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Small Modular Reactors in Italy's Energy Transition: Integrating Long-Term Planning and Hourly Weather Stress Testing

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Small Modular Reactors in Italy's Energy Transition: Integrating Long-Term Planning and Hourly Weather Stress Testing

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Highlights

- Soft-linking connects multi-year planning with 8760-hour refinement.
- Weather-year stress tests expose gaps hidden by averaged-day planning.
- Dunkelflaute makes high-VRES net-zero pathways highly storage-intensive.
- SMR cogeneration narrows the gap between planning and hourly feasibility.
- Hourly adequacy reverses the cost ranking of VRES-led and nuclear net-zero pathways.

Abstract

Energy is increasingly regarded as a strategic national asset. Long-term planning must therefore evaluate environmental sustainability, security of supply, system reliability and the affordability of system costs together. This energy trilemma becomes harder to assess when systems rely as systems rely more heavily on variable renewable energy. As a result, energy planning requires more robust modelling tools, able to connect long-term system evolution with operational performance under realistic conditions. Energy-system models used for long-term planning often simplify chronology through representative or averaged time slices. This abstraction makes large multi-year optimisation problems tractable, but it may understate the operational consequences of variable renewable energy, prolonged low-resource events and hourly adequacy requirements. This paper develops and applies a soft-linked modelling framework for Italy in which a dynamic multi-carrier energy-system optimisation model, Hypatia, defines long-term pathways across electricity, heat and hydrogen, while an hourly model, Calliope, tests selected target-year configurations under 8760-hour chronology. The coupling transfers Hypatia capacities for 2030, 2040 and 2050 to Calliope, where all non-battery technologies are fixed at their inherited levels, while additional battery capacity can be selected endogenously to meet hourly flexibility requirements.. The hourly stage is run under a Typical Meteorological Year and three critical historical weather years selected from a 45-year solar and wind dataset, including the lowest combined capacity-factor year and one-week and two-week Dunkelflaute events. Four policy-relevant cases are analysed: a conservative reference pathway, a VRES-led net-zero pathway with doubled renewable deployment limits, and two nuclear-plus-CCS sensitivities with high and low nuclear capital costs. Results show that temporal aggregation materially affects scenario interpretation. In the VRES-led net-zero case, Calliope increases 2050 battery requirements from 473 GWh in Hypatia to 26107 GWh, while the corrected system cost rises from 699 to 1866 billion EUR under the two-week Dunkelflaute case. By contrast, firm low-carbon capacity reduces the adequacy correction: in the low-costs nuclear case, 2050 battery needs remain within 161-183 GWh and the cost correction is within 10 billion EUR. The results show that operational and weather-year stress testing can fundamentally change the assessment of long-term decarbonisation pathways, highlighting the role of nuclear capacity in achieving carbon neutrality while maintaining system adequacy and limiting the cost and storage requirements associated with prolonged renewable scarcity.

Keywords

Energy system optimisation; operational adequacy; weather-year sensitivity; Dunkelflaute; Italy; long-term planning; hourly dispatch; nuclear energy

1 Introduction

Energy systems are strategic national assets, and their long-term planning must jointly address environmental sustainability, affordability, security of supply and operational reliability. This requires pathways that are credible both in their long-term system evolution and in their operational performance: the former requires coordinating investment, retirement, infrastructure expansion, technology replacement, emissions and interactions among electricity, heat and hydrogen sectors; the latter by ensuring that demand can be met hour by hour under variable renewable generation, storage constraints and limited firm capacity. This distinction becomes critical at high shares of solar and wind, when adequate annual energy balances may conceal shortages during prolonged periods of low renewable availability [1], [2].

Energy system optimisation models (ESOMs) support long-term decarbonisation planning by consistently comparing technology portfolios, policy constraints, resource limits, sector-coupling options and investment pathways [3]. To remain computationally tractable, however, they generally represent chronology through time slices, representative days or averaged profiles. These simplifications may smooth the variability governing storage operation, renewable curtailment, unmet demand and the value of firm low-carbon capacity[1]. Detailed hourly models capture chronology and adequacy more explicitly, but usually examine a single target year without endogenously reconstructing the transition pathway leading to it [5].

The methodological challenge is therefore to combine long-term and hourly models so that least-cost pathways are operationally tested before being interpreted as plausible policy options. This is especially important when reduced temporal resolution coincides with high reliance on variable renewables and short-duration storage, because operational feasibility cannot be inferred from annual or representative-day results alone [6]. It must be tested under chronological weather conditions, including both typical and adverse years [7].

Italy provides a relevant case study because its energy transition combines ambitious decarbonisation targets, high import dependence, strong but geographically uneven renewable resources, and a mismatch between resource availability and demand centres. Italy is also reconsidering firm low-carbon technologies: the 2024 Integrated National Energy and Climate Plan (PNIEC) devotes a full chapter to nuclear energy as a potential contributor to national net-zero ambitions [8]. Recent Italian nuclear studies apply long-term intertemporal, target-year hourly, multi-regional power-sector and sector-coupled models [9], [10], [11], [12], [13]. However, they generally emphasise either transition pathways or target-year adequacy.

Against this background, we assess Small Modular Reactors (SMRs) in Italy, focusing on their cogeneration potential. By supplying firm low-carbon electricity and industrial heat, SMRs affect both the generation mix and interactions between the electricity and heat sectors. The Italian case therefore provides a policy-relevant application and a methodological test of whether long-term decarbonisation pathways remain robust under hourly variability, sector coupling and meteorological stress.

To this end, we develop a milestone-year soft-link between two optimisation models. A multi-carrier planning model identifies least-cost pathways for the Italian energy system across electricity, heat and hydrogen over 2025–2060. For selected milestone years, the resulting capacities are transferred to an hourly model and tested over 8760 chronological hours. Most capacities are fixed, preserving the long-term system design, while hourly dispatch and cross-carrier interactions remain endogenous. Battery storage is the principal exception: its long-term capacity becomes a lower bound that the hourly model may expand to meet demand in every hour. The framework is therefore

[1] By firm low-carbon capacity we mean low-emission generation that can be called upon whenever needed, regardless of weather and without the energy limits of storage, such as nuclear power or natural gas with carbon capture and storage (CCS) [4].

both diagnostic and corrective, testing the operational feasibility of long-term pathways and quantifying any additional battery investment required once full chronology is restored.

A second methodological contribution concerns meteorological variability. Selected milestone-year configurations are tested under a Typical Meteorological Year (TMY) and three stress years. The TMY is constructed, and the stress years selected, from 45 years of hourly solar and wind data: 2018 has the lowest combined annual availability; 2020 contains the most severe one-week Dunkelflaute; and 2014 contains the most severe two-week Dunkelflaute. In each case, the hourly model requires demand to be met in every hour and may add battery capacity where necessary, distinguishing typical-resource adequacy from resilience under adverse conditions.

This paper assesses how hourly operational verification changes the interpretation of Italian decarbonisation pathways. It examines the adequacy of capacity-expansion pathways at key milestones, quantifies the resulting battery and cost corrections across weather cases, and interprets these findings through the Energy Trilemma dimensions of environmental sustainability, affordability and security of supply [14]. By integrating sector coupling, chronology and weather stress, the framework shows how operational verification changes the value of SMR cogeneration and competing technologies.

2 Literature review and contribution

2.1 Italian nuclear modelling efforts and the unresolved temporal-resolution problem

Recent Italian nuclear studies span complementary modelling scales but generally prioritise either long-term pathway consistency or target-year operational detail. This leaves unresolved how transition pathways perform under full hourly chronology and adverse meteorological conditions.

The policy-oriented TIMES_RSE exercise developed for the Piattaforma Nazionale per un Nucleare Sostenibile [13], using the same model family underpinning the 2024 PNIEC [8], represents a net-zero pathway in which nuclear enters from 2035 and reaches 8 GW by 2050, including cogeneration for industrial heat. PNNS complements this pathway with an operational assessment of the 2050 system [15], but does not integrate the hourly correction into pathway costs or test multiple weather stresses. Conversely, Agostini et al. [9] use the hourly Comese model [16], [17], to compare renewables-only and nuclear-containing electricity systems in 2040. Nuclear lowers total system costs despite its higher assumed generation cost, but the single-year formulation does not capture the investment and replacement dynamics leading to that configuration.

Other studies broaden the analysis in different directions. Catania et al. [10] use the multi-year FENICE model to assess 120 scenarios varying nuclear cost, construction time, network expansion and discount rate, but do not test the resulting configurations across adverse weather years. Mastrantuono et al. [11] apply a long-term TEMOA model [18] with discrete reactor investments, finding nuclear competitiveness particularly sensitive to capital cost and financing. Zacconi and Colombo [12] represent SMRs as flexible cogeneration with thermal storage in a long-term model coupling electricity, heat and hydrogen, but do not subject the pathways to hourly meteorological stress testing.

Together, these studies demonstrate that nuclear outcomes depend on techno-economic, temporal and sector-coupling assumptions, and that system value cannot be inferred from generation costs alone. None, however, combines intertemporal pathway construction, multi-energy hourly verification, cost correction and explicit testing across adverse weather conditions—the gap addressed here.

2.2 Model coupling and operational feasibility

Intertemporal energy-system models represent investment timing, technology replacement, policy constraints and cumulative costs, but commonly simplify chronology through time slices or representative periods. Conversely, hourly target-year models capture adequacy, storage operation and renewable variability in greater detail without reconstructing the transition pathway leading to the configuration. Soft-linking combines these complementary functions by transferring long-term system designs to an operational model for chronological verification.

Pavičević et al. [19] link JRC-EU-TIMES [20] to Dispa-SET, translating whole-system long-term capacities and demands into a detailed power-only unit-commitment and dispatch model. Their analysis shows the importance of operational verification in pathways with high renewable penetration and sector coupling. Fernandez Vazquez et al. [21] instead iteratively couple EnergyScope Pathway-BO and PyPSA-BO until convergence, demonstrating that capacities selected by an aggregated model may produce unmet demand when assessed at higher temporal resolution.

The present study adopts a directed milestone-year soft-link between Hypatia [22] and Calliope [23]. Hypatia determines the intertemporal pathway, after which selected configurations are tested hourly with inherited capacities fixed except for battery storage, which may expand to restore adequacy. The resulting investment requirement is used to correct pathway costs ex post instead of being returned iteratively to the planning model as in [21]. The framework further exposes each configuration to a Typical Meteorological Year and three stress cases representing low annual renewable availability and persistent one- and two-week Dunkelflaute events, a test that neither [19] nor [21] performs. Its contribution therefore lies in combining multi-energy pathway construction, hourly adequacy correction, cost adjustment and meteorological stress testing to determine whether alternative Italian decarbonisation pathways retain their relative affordability and security-of-supply performance once full chronology is restored.

3 Methods

3.1 Overview of the integrated modelling framework

The framework sequentially soft-links the intertemporal model Hypatia and the hourly model Calliope (Figure 1). Hypatia determines the least-cost evolution of the Italian electricity, heat and hydrogen system under alternative technology and policy assumptions. Installed capacities and carrier demands for 2030, 2040 and 2050 are then transferred to Calliope for 8760-hour operational verification under each meteorological case. In Calliope, inherited capacities remain fixed except for battery storage, for which the Hypatia capacity becomes a lower bound (Section 3.3). Dispatch and cross-carrier operation—including CHP production, industrial heat-pump consumption, and hydrogen production and storage—remain endogenous. Any additional battery capacity required for hourly adequacy is valued and added ex post to the Hypatia net present cost.

Electricity, heat and hydrogen demands remain separate throughout the coupling rather than being aggregated into a single electricity load. Because independently resolved hourly heat and hydrogen profiles are unavailable, their annual demands are distributed using the national hourly electricity-demand profile. Heat represents purchased (derived) heat as defined in the Italian energy balance and is projected following the PNIEC methodology; its sectoral composition is not resolved. Since the proxy profile peaks in summer, it may understate winter-concentrated heat demand and therefore the associated storage correction. Two exploratory sensitivities assess this representation: a flat repeating average-day profile tests sensitivity to intraday demand shape, while omission of the heat and hydrogen layers in selected VRES cases quantifies their contribution to the adequacy requirement. These sensitivities support interpretation of the coupling but are not included in the comparative scenario design.

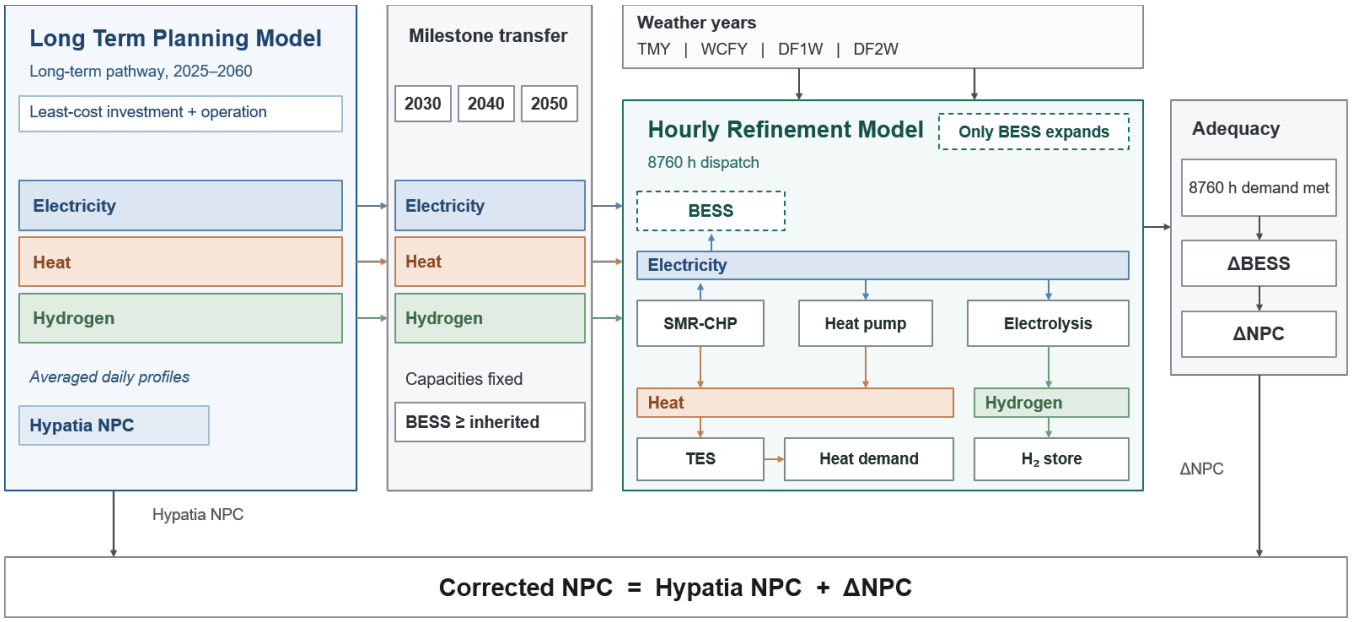

Figure 1. Sequential Hypatia–Calliope soft-link for milestone-year operational refinement and adequacy correction.

The soft-link thus provides a post-optimisation diagnostic, identifying adequacy gaps and quantifying the additional battery capacity and cost attributable to restoring full hourly chronology.

3.2 Long-term planning model: Hypatia

Hypatia [22] is a dynamic multi-year energy-system optimisation model, that minimizes Net Present Cost of the modelled system over the modeling horizon. It has been previously applied to national multi-sector transition planning [24]. Here, it represents Italian electricity, heat and hydrogen supply through power-only generation, CHP, storage, hydrogen production and flexible multi-product technologies, using the sector-coupled structure and SMR cogeneration formulation developed by Zacconi and Colombo [12].

Hypatia minimises net present system cost over 2025–2060, including investment and operating costs, subject to energy balances, technology limits, policy constraints and deployment rates. Extending the horizon beyond 2050 mitigates end effects and captures replacement and repowering of shorter-lived technologies.

For computational tractability, the model represents time through a single average 24-hour profile and Italy as one node. The profile preserves average intraday variation but omits inter-day, seasonal and multi-day chronology, while imports follow scenario-specific assumptions. These simplifications support multi-decade pathway optimisation but motivate the subsequent hourly refinement.

3.3 Hourly refinement model: Calliope

Calliope [23], widely applied in national and regional energy-transition studies [25], [26], provides the target-year operational refinement. For each scenario, Hypatia capacities for 2030, 2040 and 2050 are simulated over 8760 hours under four meteorological cases. Full chronology captures renewable variability, storage cycling and persistent low-output events omitted by Hypatia's average-day representation.

Calliope retains separate electricity, heat and hydrogen demands and the corresponding generation, conversion and storage technologies. As in Hypatia, Italy is represented as a single node; internal transmission constraints, congestion and regional resource heterogeneity are therefore excluded. Almost all inherited capacities are fixed, so Calliope tests rather than redesigns the long-term configuration. Battery energy capacity is the exception: the Hypatia value provides a lower bound that Calliope may expand, while dispatch, carrier conversion and storage operation remain endogenous.

Calliope minimises target-year Equivalent Annual Cost, including annualised investment, fixed and variable operating costs, and unmet-demand penalties. In the prescriptive adequacy setting, the penalty is sufficiently high to make unmet demand effectively prohibitive whenever additional battery capacity can restore feasibility. The optimisation

therefore measures the battery requirement needed for the inherited configuration to satisfy demand throughout each meteorological case.

The additional battery investment is used to correct the Hypatia Net Present Cost ex post:

$$NPC_{CORR} = NPC_{Hypatia} + \Delta NPC_{BESS} \quad (1)$$

$$\Delta NPC_{BESS} = \Sigma_y \left(E_y^{hourly} - E_y^{long-term}\right) \cdot c_y \cdot (1 + r)^{-(y - 2025)}, y \in \{2030, 2040, 2050\} \quad (2)$$

where E_y^{hourly} and $E_y^{long\text{-}term}$ are the installed battery energy capacities [GWh] in milestone year y resulting from the hourly and the long-term model, respectively, c_y the corresponding unit investment cost (138, 114 and 90 M€/GWh in 2030, 2040 and 2050, reflecting assumed cost decline) and r = 3% the social discount rate. Because E_y^{hourly} depends on the meteorological case, so does the corrected NPC.

3.4 Representation of SMR cogeneration across the coupled models

SMR cogeneration is represented in both models at different levels of operational detail. In Hypatia, following Zacconi and Colombo [12], reactor capacity is defined by thermal output, which is allocated between electricity and useful heat with an electrical penalty for heat extraction. Cogeneration reactors operate at rated thermal power, while endogenously sized thermal storage partially decouples heat production from demand.

Calliope represents each transferred SMR-CHP unit at its maximum-heat-extraction point, using a fixed electricity-to-heat ratio instead of Hypatia's variable extraction region. Reactor dispatch remains hourly, while inherited thermal-storage capacity is fixed. The formulation therefore preserves interactions among nuclear electricity, heat, thermal storage and competing heat technologies while simplifying cogeneration flexibility.

3.5 Meteorological data and weather-year stress tests

Hourly Italian solar PV and wind capacity factors for 1980–2024 are obtained from Renewables.ninja. The wind series uses bias-corrected MERRA-2 simulations of the current national fleet, aggregating site-level output according to the location and capacity of existing onshore and offshore installations [27], [28].

The Typical Meteorological Year is constructed month by month using the Finkelstein–Schafer (FS) statistic [29]. For each calendar month, historical candidates are compared separately with the long-term solar and wind distributions. The resource-specific distances are combined using national PV and wind capacity weights derived from Italian TSO assumptions [30]:

$$Score_m = 0.74 \cdot FS_{solar,m} + 0.26 \cdot FS_{wind,m} \quad (3)$$

The candidate with the lowest weighted score is selected for each calendar month, and the resulting months are concatenated while preserving their original hourly chronology. Annual mean solar and wind capacity factors in the resulting TMY differ from their 1980–2024 climatological means by less than 1%.

Historical stress years are selected by screening the same record using the combined annual capacity factor, minimum monthly mean, rolling 7- and 14-day minima, and persistence of prolonged low-output conditions. These indicators distinguish years with broadly unfavourable renewable availability from those containing severe sustained events, since the lowest annual resource level need not produce the greatest adequacy stress. Three historical years are retained alongside the TMY; their selection criteria and analytical roles are reported in Table 1.

Table 1. Meteorological cases used in the hourly operational refinement.

Weather case	Label	Selection criterion	Role in the analysis
Typical Meteorological Year	TMY	Month-selection from 1980-2024 hourly solar and wind profiles	Reference average weather condition
Lower capacity-factor year	WCFY 2018	Lowest overall combined VRE capacity factor	Broad renewable-resource stress
One-week Dunkelflaute year	DF1W 2020	Most severe 7-day low-output event	Short sustained scarcity stress
Two-week Dunkelflaute year	DF2W 2014	Most severe 14-day low-output event, considering depth and persistence	Multi-week adequacy stress

4 Scenario definition

The scenario architecture separates three analytical dimensions: the system's technology portfolio, which defines the available transition options; the climate-policy environment, which determines the required emissions trajectory; and targeted sensitivities, which test pathway robustness to uncertain or implementation-dependent assumptions.

Three structural configurations define the available technology portfolios. The reference configuration includes mature technologies already deployed or readily deployable in Italy. The renewables-led configuration restricts new low-carbon expansion to variable renewables, storage and hydrogen-related technologies. The nuclear-enabled configuration adds CCS, power-only SMRs and SMR cogeneration with dedicated thermal storage, allowing the optimisation to determine their deployment. These configurations define technological envelopes rather than policy scenarios.

Structural configurations are combined with either an exploratory or normative climate-policy environment. The exploratory setting imposes no explicit CO_2 trajectory, whereas the normative setting applies PNIEC-aligned transition milestones and net-zero emissions by 2050. This distinguishes cost-optimal configurations under unconstrained emissions from those compatible with the prescribed decarbonisation pathway.

Targeted sensitivities address three uncertainties: renewable deployment capability through annual PV and wind limits; nuclear competitiveness through alternative SMR techno-economic assumptions; and operational robustness through hourly testing of selected milestone-year configurations across meteorological conditions.

Four cases are evaluated through the Hypatia–Calliope framework: REF, the reference configuration without an explicit emissions constraint; VRES, a net-zero renewables-led case with doubled renewable deployment limits; and NUC-High and NUC-Low, net-zero nuclear-enabled cases with alternative SMR techno-economic assumptions. Table 2 summarises their main characteristics.

REF combines mature technologies and historically observed deployment limits without an explicit emissions constraint (Table 2), providing a BAU-like counterfactual. Its portfolio comprises gas-fired power and CHP, PV, onshore wind, batteries, bioenergy and imports, with oil progressively phased out and no new offshore wind. Because this conservative technology and deployment envelope cannot meet the PNIEC-oriented trajectory and 2050 net-zero target, REF serves as an unconstrained benchmark for assessing the additional requirements of decarbonisation.

VRES applies the net-zero policy environment to a renewables-led portfolio comprising PV, onshore and offshore wind, batteries and hydrogen technologies, while excluding nuclear and CCS-based generation. To represent favourable but finite industrial, permitting and supply-chain conditions, annual PV and onshore wind limits are doubled relative to historical maxima, while the offshore wind limit is set at twice the rate required to reach the PNIEC projection; battery expansion remains unconstrained (Table 2). The case tests the feasibility and operational implications of accelerated VRES deployment supported by storage.

NUC-High and NUC-Low apply the net-zero policy environment to a nuclear-enabled portfolio, adding CCS and both power-only and cogeneration SMRs to the renewable and flexibility options. CCS costs and deployment assumptions are calibrated to the national ministerial study [31] with national CO_2 injection capacity increasing from the Ravenna Hub pilot phase to 16 $MtCO_2$/year from 2040. SMR cogeneration is modelled at rated reactor output and coupled with dedicated thermal storage sized endogenously by Hypatia. The optimisation determines the resulting balance between power-only and cogeneration capacity. In this paper, firm low-carbon capacity refers to the SMRs (power-only and cogeneration) and the gas generation with CCS that this portfolio adds.

SMR capacity is selected endogenously from 2036, one year after the 2035 entry assumed in the PNNS/TIMES_RSE national scenario exercise [13]. Unlike PV and wind, subsequent deployment is not subject to an annual expansion limit. The resulting nuclear trajectories therefore represent cost-optimal configurations under the assumed technology availability and other system constraints, rather than forecasts of achievable construction rates or supply-chain expansion.

NUC-High and NUC-Low apply alternative SMR assumptions for overnight investment, operation, fuel and construction time (Table 2). Because Hypatia defines cogeneration capacity on a reactor-thermal basis, its overnight cost is

expressed per kWth; Table 2 also reports the equivalent cost per unit of electrical capacity at the maximum-heat-extraction operating point.

These assumptions draw on recent Idaho National Laboratory estimates [32] and bracket favourable and conservative SMR outlooks rather than predict a specific future cost. The low case is also broadly consistent with recent Italian studies, which assume overnight costs of €5,700/kWe for NOAK SMRs by 2045 and €6,250/kW for third-generation nuclear capacity in 2040 [9], [12]. Comparing NUC-High and NUC-Low tests the sensitivity of long-term system configuration and subsequent hourly adequacy to alternative SMR techno-economic conditions.

Table 2. Scenario architecture and principal assumptions.

Case	Structural Configuration	Climate Policies	Deployment assumption	SMR CAPEX	Operational Stress Test
REF	Reference / mature technologies	No explicit CO2 constraint	Historical Maxima: PV: 9 GW/year Wind onshore: 1.5 GW/year Wind offshore: 0 GW/year Batteries: 8.5 GWh/year	-	TMY, WCFY, DF1W, DF2W
VRES	Renewables-led	PNIEC + Net Zero 2050	Double of Historical Maxima: PV: 18 GW/year Wind onshore: 3 GW/year Wind offshore: 0.8 GW/year Batteries: unconstrained	-	TMY, WCFY, DF1W, DF2W
NUC-High	Nuclear-enabled: CCS + power-only and cogeneration SMRs	PNIEC + Net Zero 2050	Historical Maxima: PV: 9 GW/year Wind onshore: 1.5 GW/year Wind offshore: 0.4 GW/year Batteries: 8.5 GWh/year	CHP: €2,720/kWth (~€9,480/kWe); PP: €8,500/kWe	TMY, WCFY, DF1W, DF2W
NUC-Low	Nuclear-enabled: CCS + power-only and cogeneration SMRs	PNIEC + Net Zero 2050	Historical Maxima: PV: 9 GW/year Wind onshore: 1.5 GW/year Wind offshore: 0.4 GW/year Batteries: 8.5 GWh/year	CHP: €1,360/kWth (~€4,740/kWe); PP: €4,250/kWe	TMY, WCFY, DF1W, DF2W

Annual deployment constraints apply to gross capacity additions. Once installed capacity reaches the end of its technical lifetime, replacement uses part or all of the same allowance, reducing net additions. A technology that continuously reaches its deployment ceiling therefore eventually plateaus at a capacity determined by the annual limit and technical lifetime.

5 Results

5.1 Long-term pathways and deployment feasibility

5.1.1 Deployment constraints, replacement dynamics and the REF benchmark

REF retains the established technology portfolio and historically observed deployment limits. The PNIEC-aligned emissions trajectory and 2050 net-zero constraint are not imposed because they render this technology and deployment envelope infeasible; REF therefore provides the unconstrained benchmark for the decarbonisation pathways.

Battery additions repeatedly reach their annual ceiling, yet installed capacity eventually plateaus at 127.5 GWh. Because deployment limits apply to gross additions, substitution of retiring investment vintages increasingly absorb the new capacity annual limit. Net expansion ceases once replacement requirements equal the maximum installation rate, despite continued investment.

This mechanism applies to any finite-lived technology operating at a binding deployment ceiling: long-term expansion depends on the capacity to replace existing assets while adding new ones. It is therefore visible only in an intertemporal pathway, not in an isolated target-year capacity comparison. The result shows that historically observed deployment

capabilities are insufficient for the prescribed decarbonisation trajectory, while the resulting 2050 configuration provides the operational benchmark for the subsequent hourly assessment.

5.1.2 Accelerated renewable deployment enables net zero but increases capacity, storage and electrification requirements

VRES raises the annual PV and onshore-wind limits to 18 and 3 GW/year, respectively, and introduces offshore wind. This expanded portfolio and deployment envelope allows Hypatia to satisfy the prescribed emissions trajectory and reach net zero by 2050. REF infeasibility therefore reflects the combination of available technologies and deployment rates rather than an inability of renewables to support deep decarbonisation.

The resulting system requires rapid renewable expansion and 473 GWh of battery storage by 2050. An auxiliary run using the same technology and deployment assumptions without the net-zero constraint selects 253 GWh; the binding emissions trajectory therefore increases storage by approximately 87%. Because battery deployment is unconstrained in VRES, this difference is a result of the optimization and not an imposed by a capacity ceiling.

Part of this requirement arises from sector coupling. Electricity increasingly supplies industrial heat directly and hydrogen production through electrolysis. The heat-pump limit—representing the share of heat demand technically accessible to this technology—is binding at approximately 34%, while hydrogen-based conversion supplies a further 39%. Renewable generation and storage must consequently support both conventional electricity demand and the electrification of heat and hydrogen services, particularly as residual fossil-fuel use is eliminated around 2050.

Doubling renewable deployment rates relaxes but does not eliminate the replacement constraint observed in REF: ageing capacity must still be replaced alongside new construction. VRES therefore demonstrates long-term net-zero feasibility under accelerated deployment.

5.1.3 Firm low-carbon availability and the emergence of nuclear

NUC-High and NUC-Low introduce SMRs from 2036 within the same net-zero technology portfolio but apply different techno-economic assumptions, producing markedly different investment responses.

In NUC-High, nuclear enters gradually. SMR-CHP capacity reaches 1.22 GWth in 2040, equivalent to approximately 0.35 GWe at maximum heat extraction, and 31.65 GWth by 2050, equivalent to 9.09 GWe. No power-only SMRs are selected. Battery capacity reaches 127.5 GWh in 2050, substantially below the 473 GWh selected in VRES.

NUC-Low produces much faster deployment. By 2040, the model selects 46.05 GWth of SMR-CHP capacity—approximately 13.2 GWe—together with 3.48 GWe of power-only SMRs, giving 16.7 GWe in total. By 2050, SMR-CHP capacity reaches 58.61 GWth, equivalent to 16.82 GWe; with power-only capacity unchanged, total nuclear capacity reaches approximately 20.3 GWe. Battery capacity falls to 53.1 GWh. Because SMR additions face no annual limit after 2036, these trajectories represent cost-optimal selection rather than physically validated construction rates.

Renewable capacity remains substantial in both cases, while gas generation with CCS reaches 3.58 GW in NUC-High and 3.80 GW in NUC-Low by 2050. The introduction of nuclear therefore diversifies rather than replaces the low-carbon portfolio, shifting part of the burden from variable generation and batteries to firm capacity. The associated changes in industrial heat supply are examined in Section 5.4.

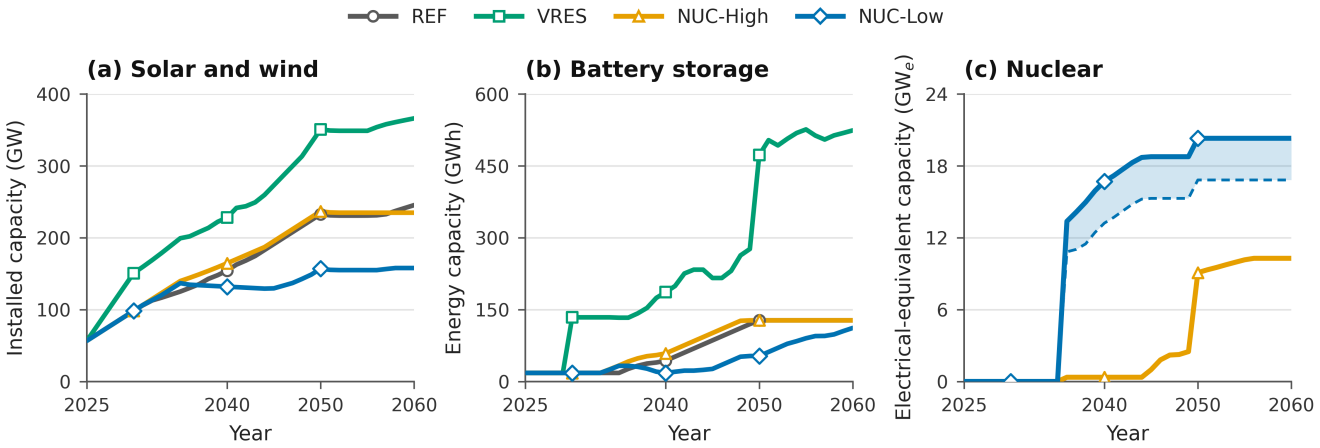

Figure 2. Long-term Hypatia capacity pathways by scenario: (a) solar and wind, (b) battery storage, and (c) nuclear capacity in electrical-equivalent terms. Markers denote the 2030, 2040 and 2050 coupling years; in panel (c), solid lines show total nuclear capacity, dashed lines SMR-CHP, and shading power-only SMRs.

5.2 Hourly refinement changes storage requirements and cost estimates

The second result concerns the effect of restoring full hourly chronology in typical meteorological year conditions, hence, independently of the additional weather-year stress tests. To provide a common reference, the comparison in this subsection considers the Typical Meteorological Year. Across all four scenarios, the hourly refinement model requires more battery capacity than the intertemporal model in 2050, but the magnitude of the correction differs markedly with the technology mix.

This correction scales with each scenario's reliance on variable renewables and batteries (Table 3): small and broadly comparable for the two nuclear cases, moderate for REF, and an order of magnitude larger for VRES, where the 2050 requirement rises more than thirty-fold, from 473 to 15,642 GWh, even though storage is already sized endogenously and without an annual deployment ceiling in the intertemporal model. This confirms that the gap reflects temporal aggregation itself, and is not the result of an exogenous constraint on storage deployment.

Table 3. Results for 2050: battery storage requirements after TMY hourly refinement and associated cost correction.

Scenario	Hypatia 2050 BESS (GWh)	Calliope TMY BESS (GWh)	ΔBESS (GWh)	NPC before -> after correction (billion EUR)
REF	127.5	1439	1312	679 -> 755
VRES	473	15642	15169	699 -> 1393
NUC-High	127.5	286	158	703 -> 715
NUC-Low	53	161	108	640 -> 649

Taken together, these cases show that the discrepancy between the long-term and hourly models is not a uniform correction, but depends strongly on the technology mix. It is largest when adequacy relies predominantly on variable renewable generation and storage, and narrows as firm low-carbon capacity reduces exposure to chronological mismatches between generation and demand. The correction also reverses the cost ranking of VRES and NUC-High: in the long-term model VRES (699 billion EUR) is slightly cheaper than NUC-High (703 billion EUR), but it becomes the most expensive net-zero case once hourly adequacy is imposed (1393 billion EUR), whereas NUC-Low remains the least-cost case overall (649 billion EUR).

5.3 Weather-year sensitivity

Weather-year sensitivity shows that low annual renewable availability does not necessarily correspond to the most demanding condition for system adequacy. Despite being selected as the year with the lowest combined annual solar and wind capacity factor, WCFY requires less battery capacity than the TMY in both REF and VRES. Annual renewable scarcity is therefore not a sufficient indicator of operational stress: the timing and persistence of low-output periods are more consequential for storage requirements.

This becomes evident under the two-week Dunkelflaute case, which is the most demanding meteorological condition across all scenarios. In 2050, BESS requirements rise to 3.16 TWh in REF and 26.11 TWh in VRES, compared with 1.44

and 15.64 TWh under the TMY, respectively. The corresponding corrected NPC reaches €861 billion and €1,866 billion. By contrast, the nuclear configurations remain substantially less sensitive in absolute and cost terms: DF2W requires 663 GWh in NUC-High and 183 GWh in NUC-Low, with corrected NPCs of €741 billion and €650 billion, respectively.

Figure 3 therefore shows that meteorological uncertainty affects transition pathways asymmetrically. Systems relying more heavily on variable renewable generation and battery storage are particularly exposed to persistent renewable-resource scarcity, whereas firm low-carbon configurations substantially reduce both the absolute storage correction and its cost sensitivity.

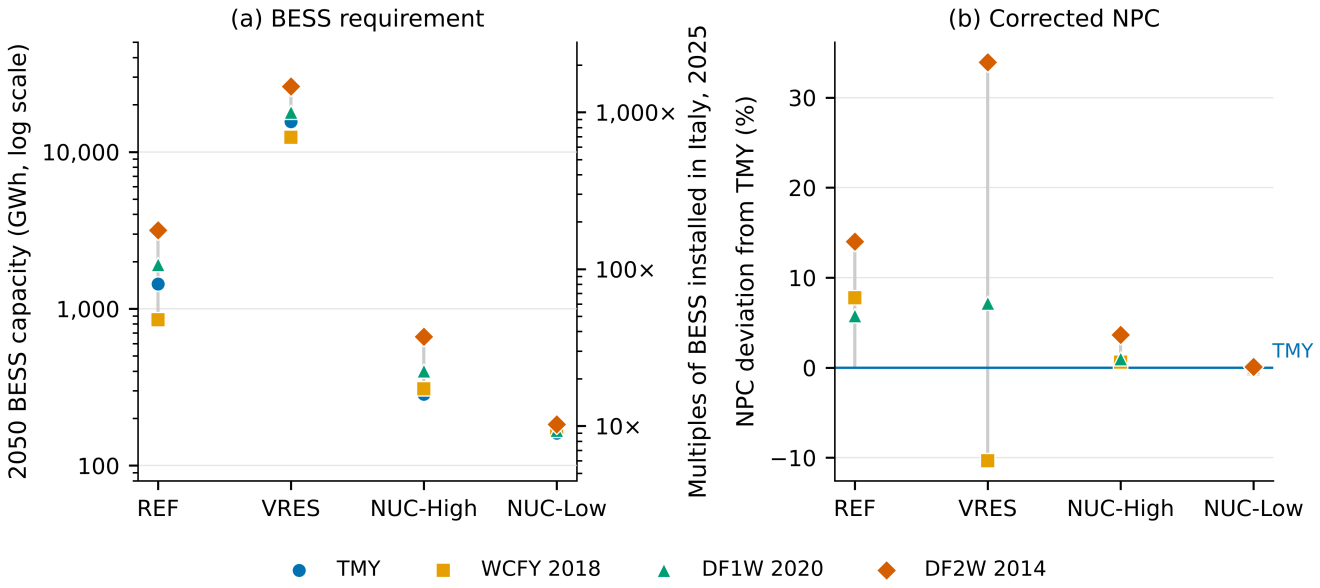

Figure 3. Sensitivity of the 2050 results to the meteorological case. (a) BESS capacity after hourly refinement, on a logarithmic scale; the right axis gives the same values as multiples of the electrochemical storage installed in Italy at the end of 2025. (b) Corrected NPC as deviation from the TMY case (horizontal line). Markers show the individual cases and grey bars their range; the four cases are designed stress tests, not a statistical sample.

Overall, the weather-year analysis shows that adequacy implications cannot be inferred from annual renewable availability alone. Persistent low-output events are more consequential than broadly unfavourable annual conditions, and their impact depends strongly on the technology mix. Meteorological stress testing therefore assesses exposure to the chronology and persistence of renewable scarcity, rather than simply applying a more conservative renewable-resource assumption.

5.4 Sector-coupling effects of SMR cogeneration

SMR cogeneration contributes to the nuclear pathways through both firm electricity and direct heat supply. By 2050, it provides 25.2 TWh of heat in NUC-High, equivalent to 34.6% of modelled heat supply, while industrial high-temperature heat pumps provide 15.2 TWh. In NUC-Low, nuclear heat increases to 46.3 TWh, or 63.7%, and heat-pump output falls to 5.7 TWh. The additional nuclear heat therefore displaces both electrically supplied heat and part of the production from biomass- and biogas-based CHP.

Hypatia also selects 16.3 GWh of dedicated SMR thermal storage in NUC-High and 27.5 GWh in NUC-Low, allowing heat recovery to be shifted relative to demand. This interaction is retained in Calliope, where heat demand remains separate and industrial heat pumps compete endogenously with nuclear and other heat technologies. Under the 2050 TMY, heat-pump electricity consumption is approximately 4.3 TWh in NUC-High and zero in NUC-Low.

A broader VRES sensitivity confirms the importance of retaining sectoral demands: removing the heat and hydrogen layers reduces required battery capacity by approximately 78% under both TMY and DF2W. By contrast, replacing the electricity-based proxy with a flat average-day profile produces materially similar requirements. Because these tests cover selected cases only, they are treated as robustness checks rather than comparative scenario results.

6 Discussion

6.1 Why model integration changes the policy message

Model integration changes the policy interpretation because each stage tests a different condition of feasibility. The long-term model captures the investment and replacement dynamics required to reach a target configuration, including capacity plateaus when gross annual deployment limits become binding. The hourly model then tests whether that configuration can meet demand under full chronology. Reduced temporal representations may smooth prolonged sequences of low renewable availability and understate storage requirements; restoring chronology reveals the residual deficits and quantifies the additional battery capacity and cost required to eliminate them. In the Italian cases, these corrections are sufficiently scenario-dependent to affect not only absolute capacity estimates but also the relative affordability and security-of-supply assessment of alternative pathways.

The technology comparison nevertheless contains an important asymmetry. VRES deployment is subject to empirically derived annual limits and the replacement burden arising as earlier installations retire, whereas SMR capacity faces no equivalent annual constraint after its assumed availability in 2036. The results should therefore be interpreted as showing how system configurations respond to alternative low-carbon technology portfolios under the modelled assumptions, rather than as comparing the maximum physically achievable deployment rates of renewables and nuclear technologies.

6.2 Weather-year sensitivity is integral to adequacy assessment

Hourly resolution and meteorological representativeness are distinct dimensions of adequacy assessment. Simulating all 8760 hours preserves within-year chronology, but the result remains conditional on the meteorological case represented. A Typical Meteorological Year provides a representative operational reference, yet cannot reproduce every historically observed combination of low solar and wind availability.

The results demonstrate why this distinction matters. Despite having the lowest combined annual solar and wind capacity factor, WCFY requires less battery capacity than the TMY in both REF and VRES. Conversely, the two-week Dunkelflaute produces the largest adequacy and cost corrections. Annual renewable availability is therefore an inadequate proxy for operational stress: the timing and persistence of correlated renewable scarcity are more consequential for storage requirements than the annual mean.

This exposure is greatest in storage-dependent configurations. Batteries can bridge renewable deficits only using energy charged beforehand, so the required energy capacity increases rapidly as low-output conditions persist. This explains the markedly larger correction in VRES under prolonged Dunkelflaute conditions. Firm low-carbon generation reduces this dependence on previously stored energy, limiting both the adequacy correction and its absolute sensitivity to the weather case. Meteorological stress testing should therefore be treated as an integral part of scenario assessment rather than a secondary robustness check. For highly renewable systems, the relevant planning question is not only how much renewable energy is available annually, but how long supply deficits persist and which combination of storage, sector coupling and firm capacity can bridge them.

6.3 Nuclear as a system-level option for Italy's decarbonisation

The nuclear-enabled scenarios show that firm low-carbon technologies should be assessed at the system level rather than through technology-specific generation costs alone. These pathways retain substantial wind and solar deployment but require less renewable overbuilding and battery storage to maintain adequacy. Under hourly verification, configurations with greater firm low-carbon capacity consequently require smaller battery and cost corrections and are less sensitive, in absolute terms, to adverse weather conditions. The portfolio therefore affects not only the generation mix, but also the scale and composition of the flexibility required to make it operationally robust.

These results indicate complementarity rather than simple substitution between nuclear and renewables. Firm generation reduces the residual balancing burden during prolonged periods of low wind and solar availability, increasing its system value when hourly adequacy and meteorological resilience are considered. This interpretation is consistent with recent Italian studies in which nuclear coexists with substantial renewable deployment while reducing storage requirements, curtailment or total system costs [10], [11].

The multi-energy formulation extends this system-level interpretation beyond electricity. Electrification and carrier conversion couple power-system adequacy to developments in the heat and hydrogen sectors, and the additional analyses show that these interactions materially affect battery requirements and dispatch. SMR cogeneration adds a further channel: direct industrial heat supply displaces both electricity-consuming high-temperature heat pumps and part of bioenergy-based CHP production. Its contribution is therefore broader than a simple reduction in electric heat demand, but should be interpreted as one component of the overall value of the nuclear-enabled multi-energy configuration [12], [13].

Viewed through the Energy Trilemma, the modelled nuclear-enabled portfolios improve affordability and operational security of supply without compromising the imposed environmental objective. They require smaller additional investments to achieve hourly adequacy and remain less sensitive, in absolute terms, to prolonged low-wind and low-solar conditions. These security benefits refer specifically to operational adequacy and meteorological resilience. Environmental sustainability is preserved: all net-zero cases satisfy the same emissions constraint while retaining substantial renewable deployment. The central finding is therefore not that nuclear replaces renewables, but that a diversified firm low-carbon portfolio can meet the same decarbonisation objective with a more affordable and weather-resilient balance of generation, storage and flexibility.

A further dimension, not quantified in this study, concerns the supply chains mobilised by each portfolio. Technology portfolios may differ not only in their operational characteristics and system costs, but also in the domestic value added they activate and in the import content associated with their supply chains. Photovoltaic and battery manufacturing capacity is currently located largely outside the EU [33], [34], while fossil-based pathways retain exposure to imported fuels [35]. Nuclear generation may instead activate a larger share of engineering, construction, maintenance and regulatory services, with external dependencies concentrated mainly in the fuel cycle [12], [36], [37], suggesting that technology diversification could also affect the industrial and external-dependence dimensions of energy security. The appropriate scale for this assessment is European as much as national: nuclear supply chains in the EU integrate manufacturing, fuel-cycle and technological capabilities across Member States [38], so the domestic contribution of Italian industry would depend on the segments it can occupy within these networks. An economy-wide assessment of domestic value added and import dependence would therefore be a natural extension of the present framework.

6.4 Methodological boundaries and next steps

Several modelling choices condition the interpretation of the hourly corrections. First, battery storage is the only capacity allowed to expand endogenously in Calliope. The resulting correction is therefore a battery-equivalent measure of the adequacy gap in the inherited configuration, not the least-cost flexibility portfolio that might emerge if generation, demand response, long-duration storage, electrolysers and interconnection could compete. The very large VRES storage volumes should accordingly be interpreted as diagnostic and not as deployment prescriptions. Second, storage incorporates charging and discharging losses but no standing loss, favouring the large energy inventories used to bridge prolonged renewable shortages. In addition, Calliope operates SMR cogeneration at the maximum heat-extraction point, rather than allowing the variable extraction represented in Hypatia, potentially understating its operational flexibility.

The coupling also remains sequential: Hypatia defines the pathway and Calliope measures its hourly correction, without feeding revised capacities and costs back into the planning model. Moreover, heat is represented as a single carrier without temperature differentiation, and Italy as a single node without internal network constraints or regional resource variation. Future work should therefore close the feedback loop, distinguish heat-temperature levels, implement variable-extraction cogeneration and resolve the Italian bidding zones. These extensions would test the robustness of both the estimated hourly corrections and the resulting pathway rankings.

7 Conclusions

This paper develops a soft-linked modelling framework for evaluating Italian decarbonisation pathways by combining long-term transition planning with hourly operational stress testing. Hypatia determines intertemporal multi-carrier pathways, capturing investment timing, technology lifetimes, retirements, replacement dynamics and interactions

across electricity, heat and hydrogen. Calliope then tests selected milestone-year configurations under 8760-hour chronology and alternative meteorological years. The results show how these two perspectives are complementary: long-term optimisation is required to represent how the system evolves, while hourly refinement is required to determine whether the resulting configurations remain operationally adequate once full chronology is restored.

The first methodological result is that reduced temporal representation can materially understate the flexibility required by highly renewable systems, even where broad capacity-expansion trends are captured correctly. In the VRES-led net-zero pathway, imposing full chronology raises the 2050 storage requirement from 473 GWh to 15,642 GWh and doubles the corrected system cost, with both rising further under the two-week Dunkelflaute (Table 3). Target-year adequacy therefore cannot be inferred from an intertemporal solution built on reduced chronology.

A second result is that hourly resolution alone is not sufficient to establish system robustness. Even an 8760-hour assessment remains conditional on the meteorological year selected. The Typical Meteorological Year provides a useful reference configuration, but historically adverse years reveal different forms of renewable-resource scarcity. The year with the lowest combined annual renewable availability and the one- and two-week Dunkelflaute cases expose progressively different adequacy challenges that cannot be inferred from annual generation alone.

Read through the Energy Trilemma that motivates this work, these findings lead to three conclusions. On environmental sustainability, net zero by 2050 can be reached either through accelerated renewable deployment or through a diversified portfolio including nuclear, but not within historically observed renewable deployment capabilities. Because annual deployment limits bind on gross installations, an increasing share of the available installation capability serves replacement rather than net expansion as earlier assets reach end of life; decarbonisation is therefore also an industrial-deployment problem, which only the intertemporal perspective reveals.

On security of supply and system reliability, firm low-carbon generation complements rather than displaces wind and solar within a transition that remains strongly based on renewable energy. In the low-cost nuclear case the 2050 storage correction is roughly two orders of magnitude smaller than in the VRES-led pathway, and both storage and corrected cost are almost unchanged between the Typical Meteorological Year and the two-week Dunkelflaute (Table 3). Firm capacity therefore narrows the gap between the intertemporal pathway and its hourly operational representation and reduces the exposure of adequacy to persistent renewable scarcity.

The multi-energy representation further shows that this comparison cannot be reduced to the electricity sector alone. Electrification of heat and hydrogen production transfers flexibility requirements between energy carriers and can materially affect electricity demand and battery requirements. Where nuclear cogeneration is selected, direct industrial heat supply provides an additional sector-coupling channel by reducing part of the electricity demand otherwise associated with heat production.

On affordability, discounted system cost is informative only once corrected for hourly adequacy. The VRES-led pathway is cheaper than the high-cost nuclear case in the long-term model but the most expensive net-zero option once full adequacy is imposed, whereas the low-cost nuclear case remains the least-cost one (Section 5.2). The relevant policy comparison is therefore not a binary choice between renewables and nuclear. The results instead support the value of assessing diversified low-carbon portfolios through environmental performance, operational resilience and system-wide affordability simultaneously, with domestic value added and import dependence as a natural extension (Section 6.3).

Taken together, the findings show that credible long-term energy planning requires more than identifying a least-cost technology mix. Transition pathways should be evaluated in terms of how they can be built and replaced over time, whether they remain adequate under full hourly chronology, how they respond to historically adverse meteorological conditions, and what wider economic and security implications accompany the resulting technology portfolio. For Italy, the analysis indicates that firm low-carbon nuclear capacity can provide a favourable system-level contribution within such a diversified decarbonisation strategy, while substantial renewable deployment remains a central component of all net-zero pathways examined.

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