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Consulting Services

BUILDING SPAIN'S NET ZERO POWER SYSTEM

Pathways, Trade-offs and System Choices

Whitepaper

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EXECUTIVE SUMMARY

Spain's efficient transition to a reliable and resilient net zero electricity system by 2050 is achievable, but it will depend significantly on ensuring adequate flexibility resources in the system in order to maximize the value of Spain's high solar and wind potential.

Spain's power system is undergoing a significant transformation, with renewable energy at the core of the country's energy transition. Generation from wind, solar, and hydro accounted for nearly 57% of total electricity production in 2024. This share is expected to increase in the coming years, driven by the updated National Energy and Climate Plan (NECP). The NECP commits Spain to a 55% reduction in CO_2 emissions relative to 2005 levels, in line with the EU-wide target of a 62% reduction by 2030. This is further reinforced by the European Climate Law, which sets a legally binding target of net-zero emissions by 2050.

Achieving these emissions reductions relies on a rapid expansion of renewable generation, with the NECP setting a target of at least 81% of electricity production from renewable sources by 2030.

The pace of change is reshaping system dynamics and the importance of strengthening resilience was illustrated in April 2025 when a major blackout affected large parts of the Iberian Peninsula, highlighting the need to assess how high renewable operation, interconnection limits, and available dispatchable reserves may interact under stressed system conditions.

To understand the impact of these ambitious emission reduction and renewables penetration goals coupled with a projected 60% growth in demand by 2050, there is a need to explore credible pathways to achieve net zero in Spain. These pathways should investigate the role of various zero- or low-carbon electricity generation technologies as well as the impact on the electricity grid to efficiently enable this transition to net zero.

This paper explores alternative decarbonization pathways for Spain's power sector, considering the economic implications of different electricity generation technologies and capacity expansion strategies to reach net zero by 2050. The paper provides insights into the challenges and opportunities to inform industry stakeholders in order to support informed decision-making and effective planning for a stable and resilient future power system in Spain. The pathways considered are:

1. **Business-As-Usual:** represents the evolution of the power system under an unconstrained power generation capacity buildout. CO_2 emission targets are not explicitly enforced, instead, carbon prices are applied to incentivize decarbonization.
2. **Progressive:** shows the evolution of the power system under emissions constraints aligned with Spain's NECP. Maintains a technology-neutral framework, where renewables expand at historic growth rates.
3. **Pioneering:** considers stricter constraints on variable renewable deployment and incorporates emerging technologies (green hydrogen, SMRs, offshore wind). The operational lifetime of existing nuclear plants is extended until the mid-2040s.
4. **Lower Carbon:** an electricity system where demand is met exclusively by Lower Carbon technologies. Nuclear plants' lifetimes are extended as in the Pioneering scenario. It results in the highest deployment of variable renewables, battery storage, and SMRs.

In all pathways, the least-cost expansion approach is applied to determine the optimal portfolio of generating technologies to deliver net zero by 2050 as shown in Figure 1. The Pioneering and Lower Carbon pathways include a requirement for green hydrogen within the generation mix, and therefore include an estimate of the additional renewable capacity required to produce this hydrogen via electrolysis. By contrast, hydrogen plays a more limited role in the Progressive and Business-As-Usual (BAU) pathways, where the modeled flexibility requirement is met primarily by power plants equipped with carbon capture and storage (CCS).

Our analysis demonstrates that **Spain can achieve its net zero goals** through a successful transition to lower-carbon energy through a combination of technologies. The resulting generation under each scenario is shown in Figure 2. Total solar and wind capacity could potentially range from 150 GW to over 250 GW by 2050. The higher the level of wind and solar the more battery storage will be required to ensure efficient use of this generation.

However, meeting net zero targets while **ensuring system reliability will need a high level of flexibility in the system.** All scenarios require 15-20% of flexible capacity, whether that is low carbon thermal or battery storage, to ensure that there is sufficient capacity on the system to provide services that maintain frequency and voltage as renewable penetration increases.

The resulting generation under each scenario is shown in Figure 2. The requirement to maintain system reliability results in the need to maintain a level of available flexible thermal generation even in the most extreme renewable pathway.

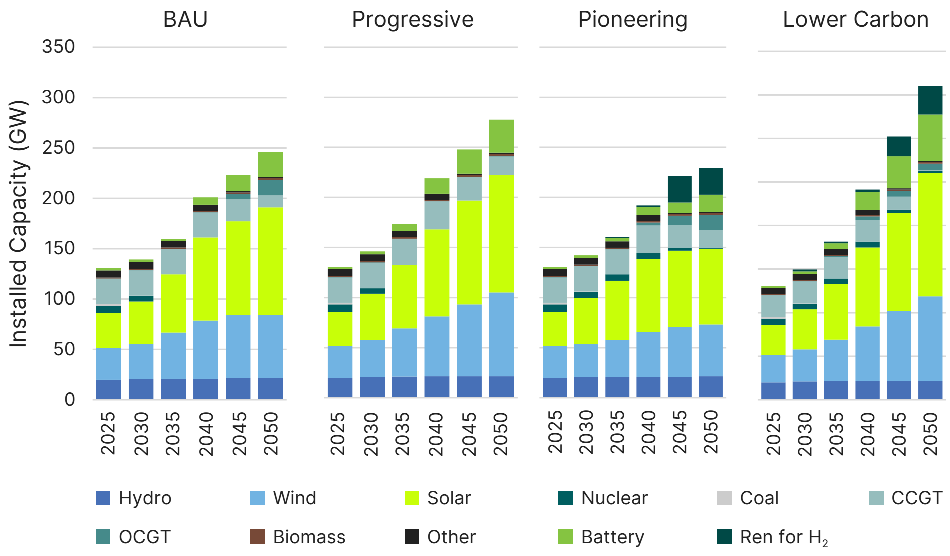


Figure 1 – Projected Capacity Summary

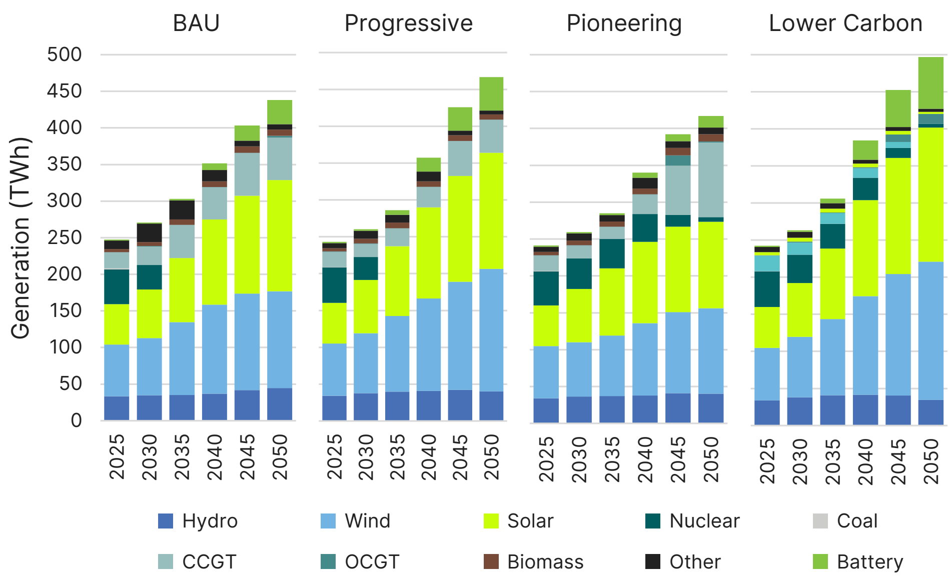


Figure 2 – Projected Generation Summary

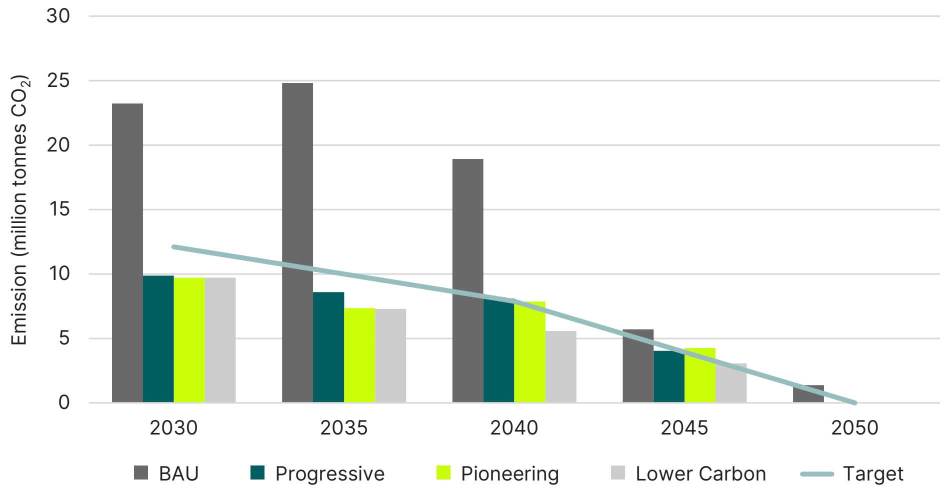


Figure 3 – Projected Carbon Emissions

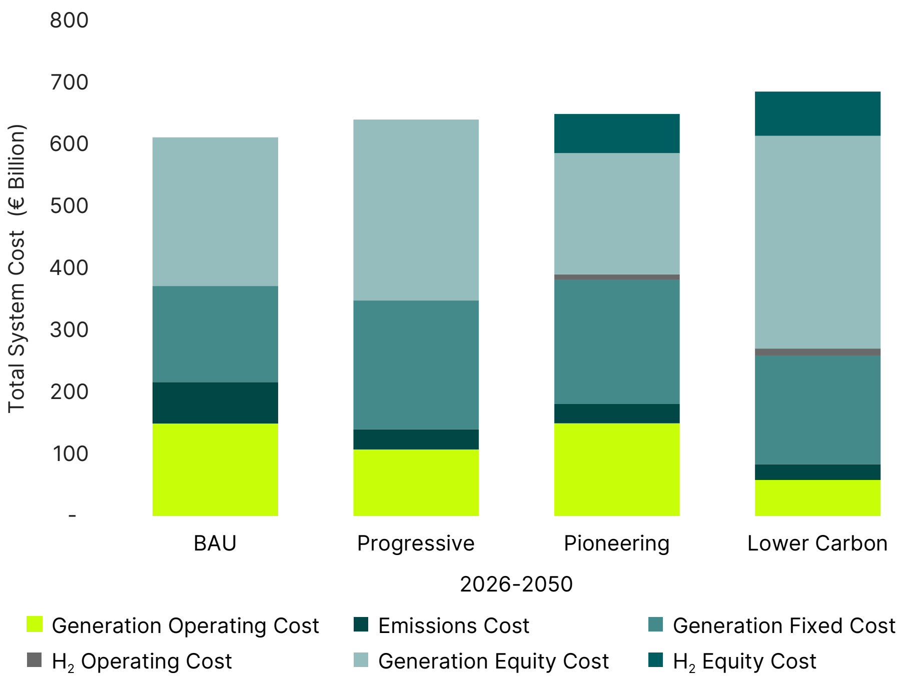
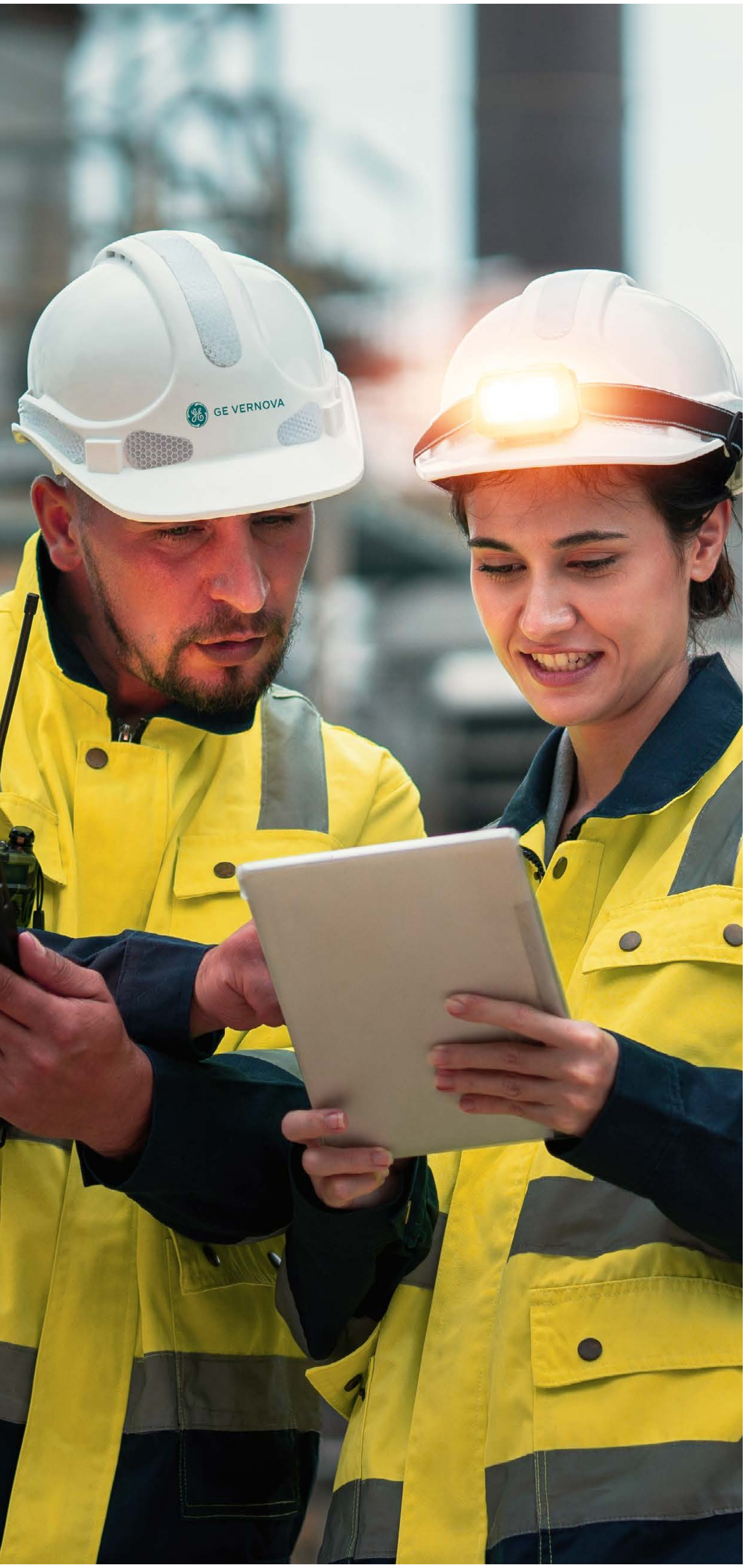


Figure 4 – Projected Total System Costs 2026-2050 (nominal)

All scenarios, except for the BAU scenario, are consistent with the decarbonization pathways to net zero, as shown in Figure 3. Even the BAU scenario, where emissions are penalized with a carbon tax – in line with the projected EU ETS emission price – is close to net zero by 2050 although misses significantly by 2030. This indicates that if the 2030 emission targets are to be met then renewable generation will need to be incentivized to ensure a significant move away from generation from existing thermal assets.

The overall cost of the transition to net zero under each scenario will be a combination of the investment and operational costs including the additional costs to produce hydrogen, presented in Figure 4. The scenarios with a more balanced mix of renewables and low-carbon technologies, such as the Progressive scenario, appear to offer a balanced trade off between cost, emissions, and investment pacing under the modeled assumptions, aligning well with realistic deployment and financing conditions. The Lower Carbon scenario illustrates the system cost implications of a larger share of variable renewables, with the generation equity cost being the highest among all scenarios, reflecting the requirement for high levels of batteries to store the excess renewable generation for use at times of peak demand as well as requiring additional Open-cycle gas turbines (OCGTs) peaking capacity operating on hydrogen to provide system security.



When considering the generation pathways to net zero, it is also important to assess the implications for the transmission network and to identify potential system constraints. If we consider, the Lower Carbon scenario as the extreme case for the deployment of renewable capacity across the network, the results indicate that the transmission system can accommodate this capacity, provided that new wind and solar installations are incentivized to locate across Spain rather than concentrating in a limited number of regions. This is a stylized but plausible assumption, given the relatively broad distribution of renewable resources nationwide; actual siting choices, however, will depend on permitting, network access, and project economics. Under these conditions, the principal transmission constraint is expected to arise on the 400 kV lines supplying the Barcelona region, which will require reinforcement to enable increased west–east power transfers.

The challenge will be to ensure this investment in capacity occurs in a timely manner which will require policy, regulatory and market support, in particular:

- Standardize and streamline of the authorization of connection procedures to ensure capacity is connected in an efficient manner.
- Evaluate whether locational price signals for new capacity, either through capacity or energy markets, could help spread new capacity more efficiently across the network.
- Consider targeted support or market reforms for battery storage projects where needed to help ensure increasing levels of wind and solar capacity can be utilized efficiently and curtailment is minimized.
- Assess closer co-optimization of the day-ahead and ancillary services markets to improve the economic and operational case for renewable generation and storage to provide synthetic inertia, frequency control, and voltage support.
- Consider whether extending the operational lifetime of existing nuclear power plants, potentially up to 60 years, could reduce overall system costs and support reliability during the transition, subject to policy, regulatory, and technical review.
- Support for grid infrastructure enhancements, specifically on the west – east 400kV lines.

In conclusion, Spain's efficient transition to a reliable and resilient net zero electricity system by 2050 is achievable, but it will depend significantly on ensuring adequate flexibility resources in the system in order to maximize the value of Spain's high solar and wind potential.

1. INTRODUCTION

1.1 Context and Objectives

Spain's power system is undergoing a significant transformation, with renewable energy at the core of the country's energy transition. In 2024, nearly 57% of all electricity generated came from wind, solar, and hydro power, a historic record that highlights the central role of renewables in the country's energy transition.

This transition is driven by European policy. The European Green Deal followed by the "Fit for 55" package, sets binding Greenhouse Gas (GHG) emissions reduction targets for each Member State of the European Union (EU) to achieve climate neutrality, or net zero, by 2050. The Climate Change and Energy Transition Act, Law 7/2021, sets a legal framework for Spain to achieve this climate neutrality by 2050. This is further reinforced by the European Climate Law which sets a legally binding target of net zero emissions by 2050. Consequently, Spain defined its recent National Energy and Climate Plan (NECP)[1] that includes a set of planned measures to reduce CO_2 emissions by 55% compared to 2005 levels, aligning with the EU's 62% reduction target for 2030. This is expected to be accomplished by setting a target of at least 81% of generation to come from renewable sources by 2030.

The transition is further shaped by the imminent phase-out of coal and by the scheduled phase-out of nuclear power between 2027 and 2035. The nuclear retirement timeline, however, remains the subject of political and technical debate, with the possibility of lifetime extensions being considered. While strategic interconnection projects such as the Bay of Biscay HVDC line are advancing, their benefits will only materialise towards the end of the decade.

Against this backdrop, and with reference to the operational lessons that may emerge from the Iberian blackout in April 2025, it is essential to undertake a comprehensive power dispatch study to provide a rigorous and operationally realistic assessment of the system's trajectory. This study has two core objectives:

- First, to compare alternative decarbonization pathways, assessing their implications for security of supply, system costs, and emissions. These pathways include scenarios with and without nuclear lifetime extensions, accelerated deployment of renewables and storage, and the integration of low-carbon dispatchable technologies (e.g. carbon capture and operation with hydrogen).
- Second, to accurately capture the dynamics of operating the power system under each of the pathways to understand the implications on system operation, cost, and security.

The results of this study will deliver critical insights for policymakers, industry stakeholders, and investors, enabling the anticipation of risks and evaluation of trade-offs, and guiding investment decisions as Spain advances towards a carbon-neutral electricity system.

1.2 Scenarios Overview

The scenarios in this study were designed to capture Spain's current dynamics and to explore alternative power dispatch pathways that align with the ambition to decarbonize by 2050:

- **Business-As-Usual:** represents the evolution of the power system under an unconstrained power generation capacity buildout. CO_2 emission targets are not explicitly enforced, instead, carbon prices are applied to incentivize decarbonization.
- **Progressive:** shows the evolution of the power system under emissions constraints aligned with Spain's NECP. Maintains a technology-neutral framework, where renewables expand at historic growth rates.
- **Pioneering:** considers stricter constraints on variable renewable deployment and incorporates emerging technologies (green hydrogen, small modular reactors (SMRs), offshore wind). The operational lifetime of existing nuclear plants is extended until the mid-2040s.
- **Lower Carbon:** an electricity system where demand is met exclusively by Lower Carbon technologies. Nuclear plants' lifetime is extended as in the Pioneering scenario. It results in the highest deployment of variable renewables, battery storage, and SMRs.

[1] Spain – Final updated NECP 2021-2030, https://commission.europa.eu/publications/spain-final-updated-necp-2021-2030-submitted-2024_en

Scenario	Approach	Highlights
BUSINESS-AS-USUAL (BAU)	Market-driven expansion, primarily relying on carbon pricing.	Lowest short-term cost; fails to reach net zero by 2050; moderate curtailment; highest emissions.
PROGRESSIVE	Aligned with the National Energy and Climate Plan (NECP); high renewable growth with gas + CCS backup.	Achieves net zero with moderate system stress; balanced cost and emissions; moderate curtailment.
PIONEERING	Combines renewables with hydrogen-ready infrastructure, CCS, extended nuclear, and SMRs.	Technologically diversified and resilient; capital-intensive; low resilient; capital-intensive; low curtailment.
LOWER-CARBON PATHWAY	Maximizes renewables, storage, hydrogen, and SMRs.	Deep decarbonization; lowest emissions; highest operational and investment complexity.

Each pathway represents a trade-off: no single option optimizes cost, emissions, and reliability simultaneously. The choice reflects priorities in ambition, affordability, and system resilience.

All pathways except for the BAU scenario, are consistent with the emissions objectives of Spain's National Energy and Climate Plan (NECP), including achieving net-zero emissions by 2050. Other common assumptions are:

- Identical electricity demand growth trajectory, capturing electrification of heat, transport, and digital sectors, reaching a peak demand of 65 GW and total electricity consumption of 383 TWh by 2050.
- A minimum capacity reserve margin of 10%.
- Cross-border interconnection expansion in line with the 2024 ENTSO-E Ten-Year Network Development Plan.
- Reserve holding requirements for hydro and thermal power plants in line with the ENTSO-E's Pan-European Market Modelling Database (PEMMDB).
- Gas power plants have the option to invest in order to continue operation as low-carbon generators: CCGTs can be retrofitted with CCS and OCGTs can be converted to operate on hydrogen.

1.3 Geographic Scope of the Analysis

This paper focuses on the Spanish electricity system. However, Spain and Portugal operate a unified electricity market. Consequently, both countries are modeled in detail at the plant level, whereas neighbouring countries are represented as aggregated plants using price points.

The model represents Spain using three different levels of aggregation: regional, zonal, and nodal. Each level of detail offers its own advantages.

- The regional model is primarily used for long-term planning.
- The zonal model is employed for unit commitment and economic dispatch to allow us to understand the impacts of decarbonization at a regional level.
- The nodal model is utilized for transmission congestion analysis.

The zonal model divides Spain into its autonomous communities, while the nodal model includes the high-voltage substations and transmission lines of 220kV and above. Figure 5 below shows the geographic scope of the analysis.

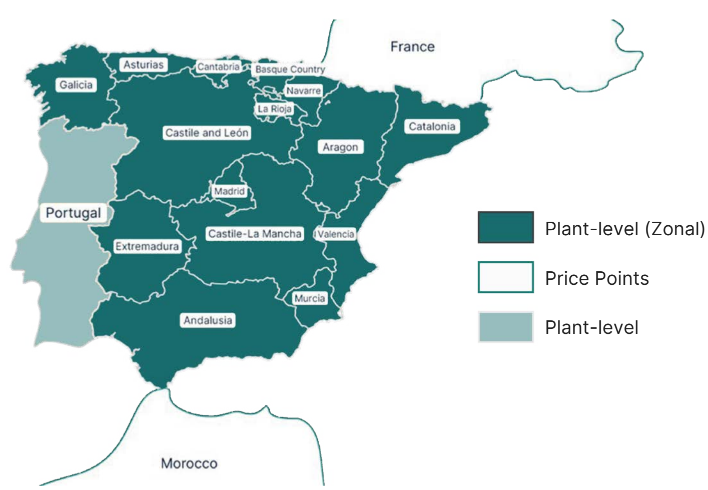


Figure 5 – Geographical Scope

Scenario	Cost	Emissions	Curtailment	Assessment
BUSINESS-AS-USUAL (BAU)	Lowest	Highest	Moderate	Economically attractive short term; fails climate targets
PROGRESSIVE	Moderate	Net zero achieved	Moderate	Balanced transition; credible and implementable
PIONEERING	Higher upfront	Net zero achieved	Lowest	Technologically diversified; capital intensive
LOWER-CARBON PATHWAY	Highest	Lowest	Highest	Deep decarbonization; operationally demanding

Insight: the cheapest pathway is not always the most efficient long-term. True efficiency comes from minimizing curtailment, aligning renewables with dispatchable resources, and controlling congestion costs.
Affordability is determined by system design, not just generation costs.

1.4 Technology Candidates

The list of candidate technologies to serve forecasted demand growth and their projected capital costs over the period to 2050, sourced from NREL[2], is shown in Figure 6. Nuclear SMRs and Offshore Wind capital costs are projected to decrease significantly over time as the technology matures.

The resulting Levelized Cost of Electricity (LCOE), shown in Figure 7, reflects the combined effect of investment cost, operating costs, efficiency, and an assumed utilization rate. Solar PV and onshore wind have the lowest LCOEs, driven by low capex and operating costs. With regards to pumped storage, this study assumes that one new reservoir is paired with an existing reservoir, hence the lower LCOE.

By contrast, offshore wind exhibits a higher LCOE, driven by the greater capital and O&M costs of floating offshore turbines — the most suitable long-term technology for Spain's deep coastal waters. Despite these higher costs, offshore wind remains a key component of Spain's government roadmap, with 3 GW targeted by 2030.

Dispatchable technologies such as hydrogen-ready OCGTs or CCS-equipped CCGTs and SMRs show higher LCOEs, but can play an important role in ensuring system reliability and flexibility. These are not yet proven at scale in Spain, but our scenarios include them to test sensitivity and system cost implications.

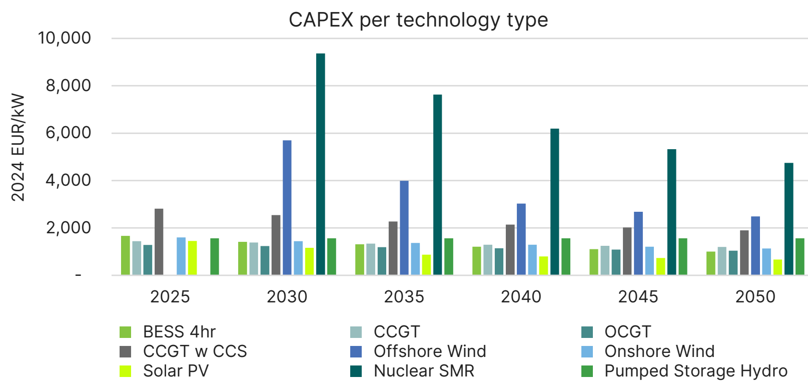


Figure 6 – Technology cost assumptions (real 2024)

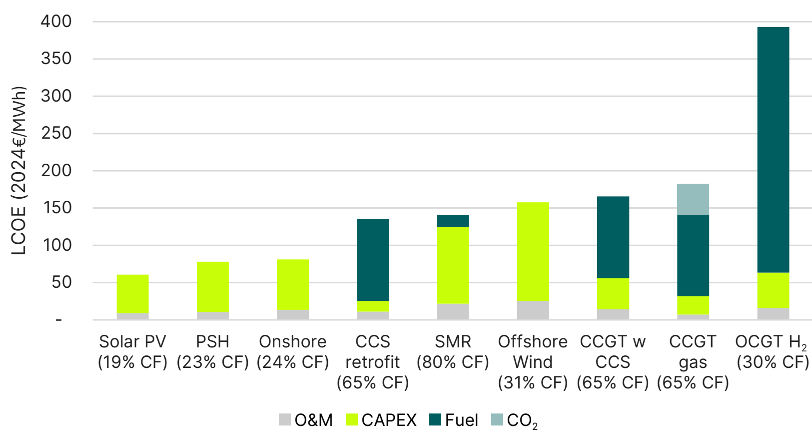


Figure 7 – LCOE (nominal) comparison for different technologies in 2035. Capacity factors used for the LCOE calculations are illustrative.

[2] National Renewable Energy Laboratory. (2024). Annual Technology Baseline (ATB) – Electricity Data [Dataset]. https://atb.nrel.gov/electricity/2024/data

2. GENERATION PATHWAYS TO NET ZERO

The four scenarios define distinct strategic directions for Spain's power system. What sets them apart is not only the scale of ambition, but how the generation mix evolves over time and how that evolution reshapes system dynamics, operational challenges, and investment needs.

1. Moving from strategic intent to operational reality requires answering four core questions:
2. How much capacity mube built to meet demand and net-zero targets?
3. What will the generation mix look like by 2050, and how will different technologies interact?
4. How will emissions decline over time, and which pathways meet climate commitments?
5. What are the implications for system costs, infrastructure stress, and operational flexibility?

This section explores how each scenario converts ambition into capacity expansion plans and operational outcomes, revealing the trade offs between cost, flexibility, and decarbonization performance.

2.1.1 Scenario Driven Pathways

Figure 8 illustrates new build capacity by technology across different scenarios in five-year blocks, excluding small solar CSP and hydro capacities for clarity. The chart also includes the additional capacity of renewables dedicated to electrolysis to produce the volume of green hydrogen required for electricity generation in the Pioneering and Lower Carbon scenarios

The significant variance in total annual capacity build-out across scenarios is primarily due to the difference in dependable capacities that are available at system peaks: variable renewables (wind, solar) have low dependable capacities because of their reliance on weather, whereas thermal technologies (CCGTs, SMRs) offer close to 100% dependable capacity, requiring less investment to meet system reserve margins.

It should be noted that the solar and wind build out are net new additions. We have assumed that the existing capacity will be repowered when required at the same capacity.

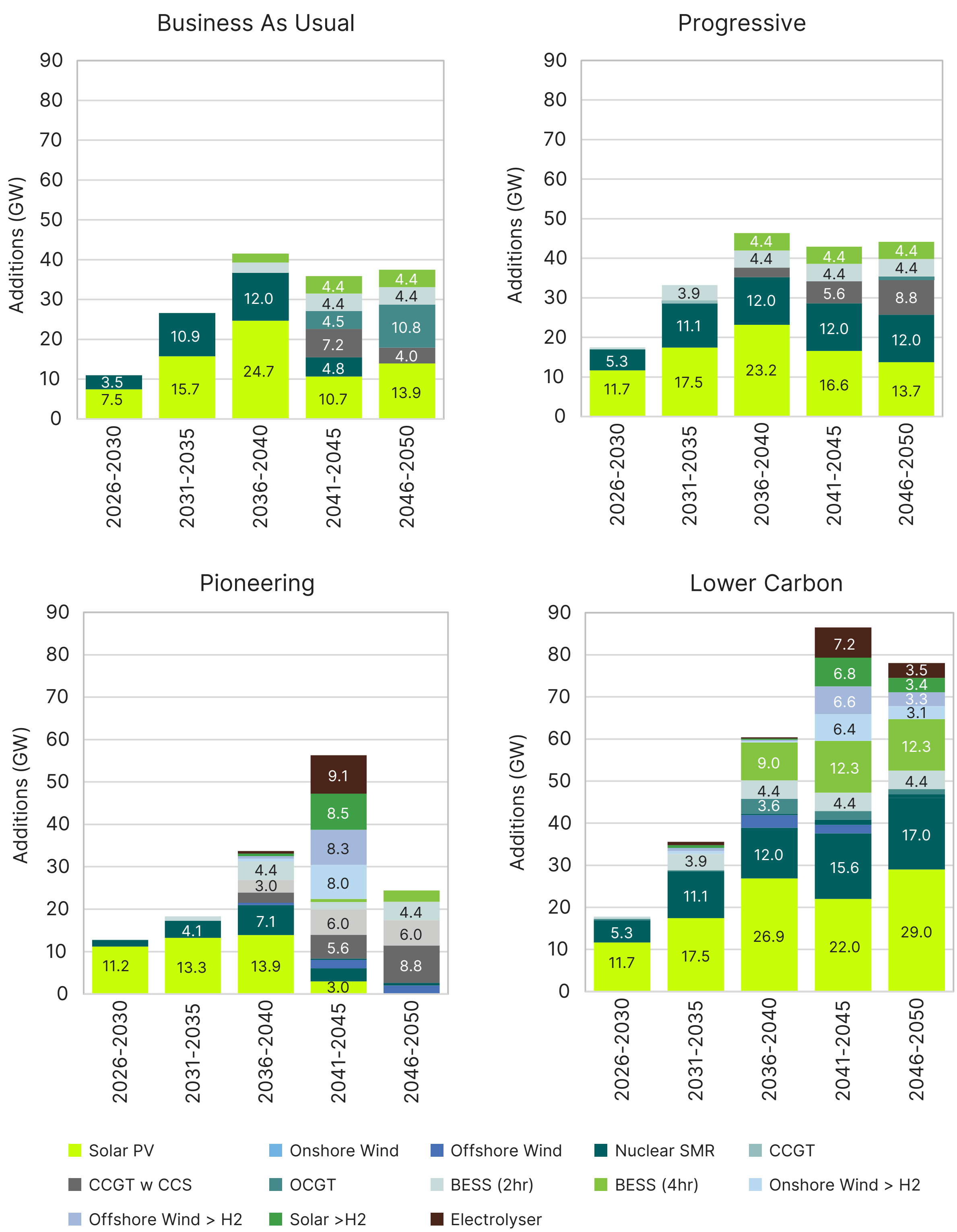


Figure 8 – Summary of capacity additions in Spain between 2025 and 2050

The model outcomes emphasize the need to maintain dispatchable thermal capacity to meet demand and reserve requirements as emissions constraints tighten. Across all scenarios, a substantial amount of thermal capacity is added. Where permitted, CCGT with CCS is consistently built, reflecting the shift toward low- or zero-carbon dispatchable options and in all scenarios, except the Lower Carbon scenario, the Algeciras CCGT is the only existing power plant that is retrofitted with CCS capability. The build of the individual technologies varies across each pathway as follows:

- **Business as Usual:** Renewable capacity expands gradually, and abated gas turbines are favored over unabated ones in the early 2040s. Open-cycle gas turbines (OCGTs) are the preferred option for meeting reserve margin requirements due to their lower capital expenditure.
- **Progressive:** Renewable capacity expands at historic growth rates. As nuclear capacity is phased out by 2035, CCGTs with CCS are deployed to meet demand while complying with emissions limits. OCGTs are constructed primarily to satisfy peaking and reserve margin requirements. Battery storage is added to enhance system flexibility, with a preference for lower-cost two-hour duration systems over more expensive four-hour configurations.
- **Pioneering:** Build-out of combined-cycle gas turbines with CCS is maintained at levels consistent with the Progressive scenario, while OCGTs are required to operate on green hydrogen from 2035 onward. Overall, this scenario results in the highest deployment of thermal generation technologies, over 32 GW by 2050, and the lowest levels of battery storage and variable renewables, excluding renewable capacity dedicated to green hydrogen production.
- **Lower Carbon:** Highest deployment of renewables, battery storage, and small modular reactors (SMRs). Over 8GW of OCGTs are deployed by 2050 primarily to provide system flexibility and reliability and are assumed to operate on green hydrogen.

2.1.2 Location of New Capacity

It is necessary to ensure the location of new capacity across Spain is practical from a resource, planning, and grid perspective. Figure 9 details the assumptions and methodology employed for this allocation.

Solar, Wind & BESS	New solar PV, onshore wind and batteries are allocated proportionally based on land area in each autonomous community.
Offshore Wind	Offshore wind capacity location is informed by the geographic distribution of currently proposed offshore wind projects in Andalusia, Galicia, and Catalonia
CCGT with CCS	CCGT with CCS is allocated to retired thermal power plants situated in historically industrial regions. The distribution across the zones is done based on the weighting of demand.
CCGT & OCGT	Other thermal technologies, such as CCGTs and OCGTs, are allocated to regions not already designated for CCGT with CCS capacity.
Nuclear SMR	Nuclear SMR deployment is targeted to regions with decommissioned nuclear facilities, with allocation based on the capacity of the retired plants.

Figure 9 – Zonal capacity allocation assumptions

2.2 Electricity Generation

By 2050, renewables supply ~70% - 80% of Spain's electricity, depending on the scenario. This substantial shift changes system dynamics: variability rises, peak management becomes more complex, and reliable backup becomes critical.

Flexible thermal technologies — particularly CCGTs with CCS and hydrogen-capable OCGTs — provide essential firm capacity during periods of low wind and solar output. In the Pioneering scenario, innovative combinations of renewables and firm low-carbon generation reduces system stress. The key insight is that a renewable-dominated system is not a renewable-only system; reliability depends on complementarity between variable and dispatchable generation.

As such, each scenario reflects a distinct generation strategy:

- **BAU:** High share of variable renewables with limited firm capacity. Flexible gas and batteries balance variability and maintain security of supply. Renewable generation reaches 68% by 2030, below Spain's NECP target of 81%.
- **Progressive:** Higher renewable share, reduced gas reliance, and a more balanced transition. Renewable generation peaks at 85% by 2035 but gradually declines to 80% by 2050 as CCGTs with CCS and batteries take on a larger share.
- **Pioneering:** Slower renewable expansion but a more diversified technology mix, including nuclear, offshore wind, and flexible gas. Renewable generation rises to 76% by 2035 and falls to 68% by 2050, reflecting reliance on firm low-carbon capacity for reliability.
- **Low Carbon:** Almost complete fossil fuel phaseout, relying on a mature hydrogen economy, extensive storage, and grid reinforcement. Renewable generation reaches 81% by 2050, illustrating a technically demanding but deeply decarbonized system.

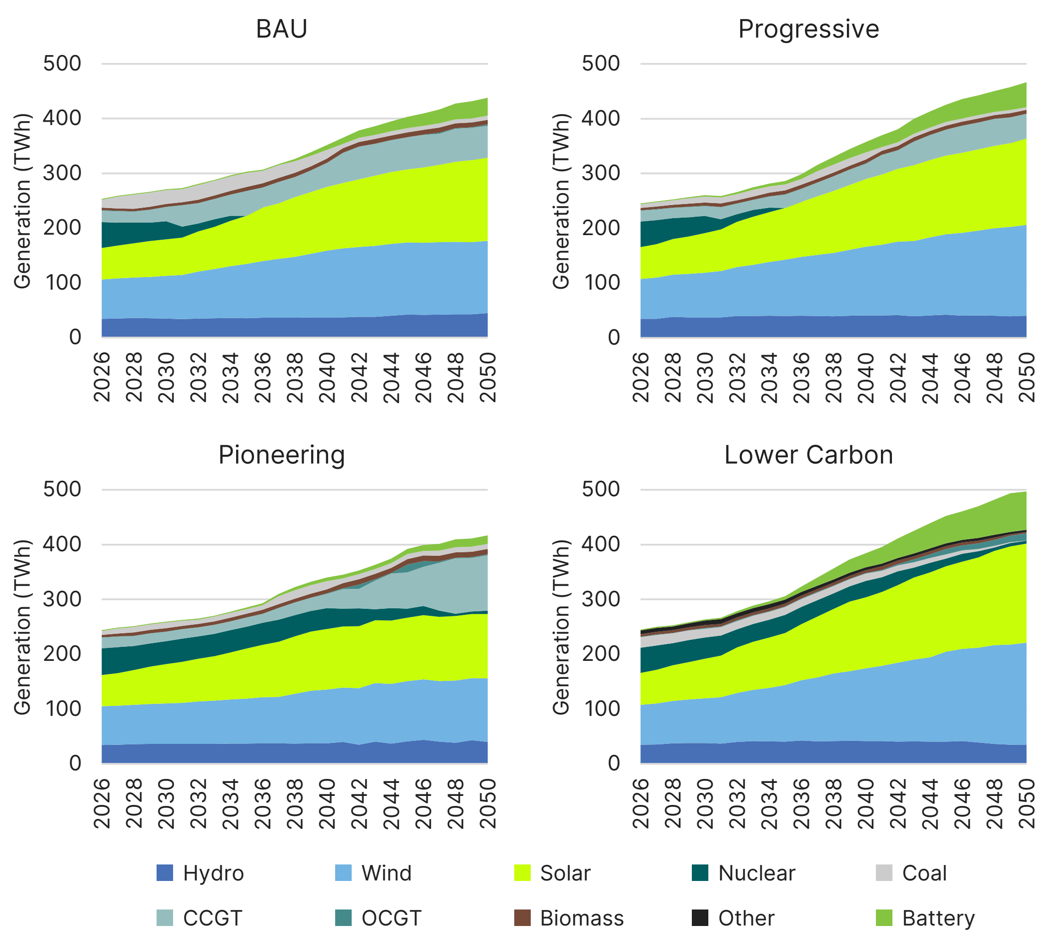


Figure 10 – Projected Generation

2.2.1 Low Carbon Generation

Across all scenarios, CCGTs with CCS and OCGTs capable of operating with hydrogen become increasingly important sources of dispatchable, flexible capacity — especially in the 2040–2050 period as fossil-based generation is phased out.

Hydrogen begins to appear as a generation fuel from 2030 onward, with a different evolution across scenarios. In the Lower Carbon scenario, which pursues full decarbonization by 2050, hydrogen penetration in OCGTs is immediate and steep - rising from 58% in 2030 to 100% by 2045. By contrast, in the Pioneering scenario, the hydrogen transition starts later but accelerates rapidly after 2037, surpassing 90% by 2041 and also reaching full substitution (100%) by 2050.

The deployment of CCGTs with CCS follows a similar decarbonization trajectory but varies across scenarios: under our technology aggressive Progressive scenario, CCS integration is modeled to begin as early as 2027, expanding steadily to reach full modeled coverage across CCGTs by 2046. The Pioneering scenario delays CCS adoption until 2037 but achieves full coverage by the mid-2040s. The BAU scenario, while slower in initial adoption, gradually increases CCS implementation after 2040, reaching around 80% of total CCGT generation by 2050.

Hydrogen-based OCGTs supply short-term balancing and peak support, while CCS-equipped CCGTs deliver mid-merit generation and stable baseload output. By 2050, both the Pioneering and Lower Carbon scenarios nearly fully decarbonize thermal generation through these complementary pathways, underscoring their essential role in a resilient, carbon-neutral power system.

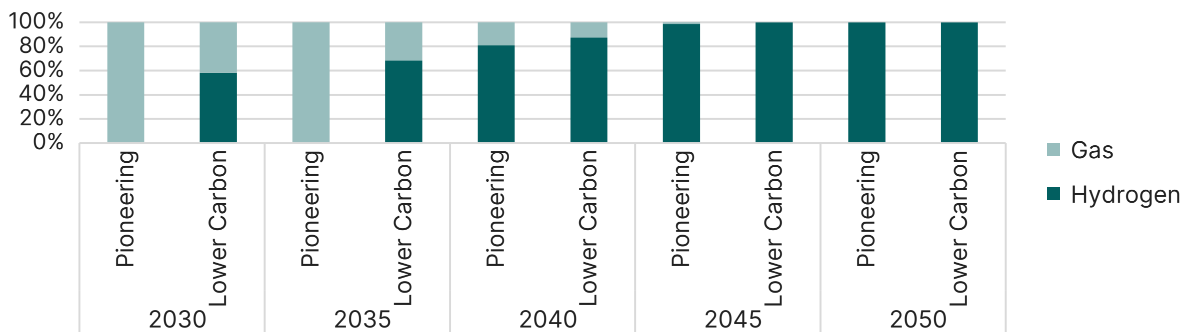


Figure 11 – Share of OCGT power generation with H_2

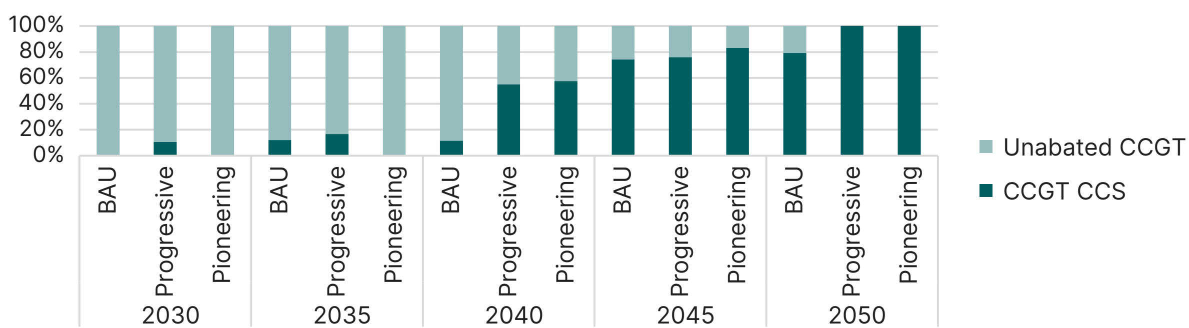


Figure 12 – Share of CCGT w/CCS power generation

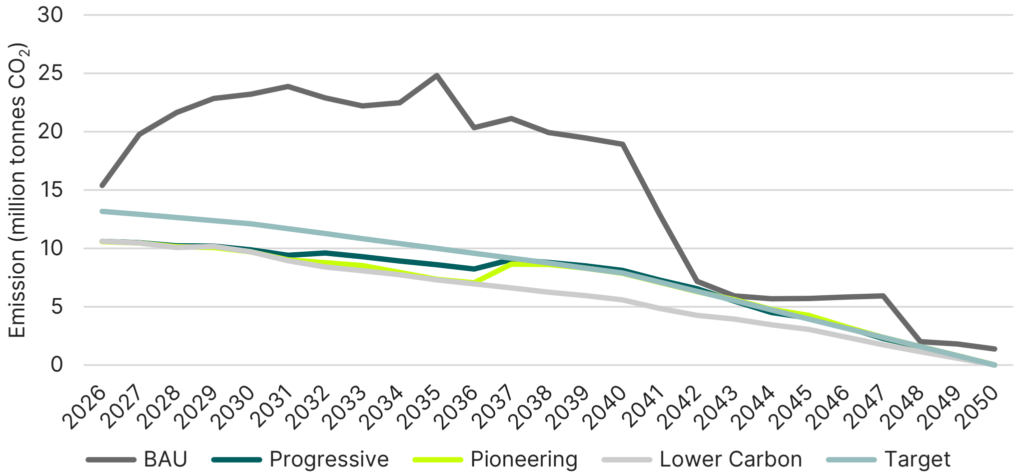


Figure 13 – Annual Carbon Emissions

2.3 Carbon Emissions

The emissions trajectory under each scenario is presented in Figure 13. The carbon targets for this analysis align with the latest Spain NECP, assuming 13.4 million tonnes CO_2 by 2030 and net zero by 2050.

All scenarios, except for the BAU scenario, are constrained to ensure compliance with the targets. However, under the BAU scenario, emissions are penalized with a carbon tax – in line with the projected EU ETS emission price – and consequently the 2030 target is missed, emitting 23 million tonnes of CO_2 by 2030. However, a steeper increase in the carbon price in the last 10 years incentivizes the increasingly rapid uptake of renewables and lower-carbon thermal technologies, leading to a significant reduction in emissions. By 2050, the system does not reach net zero but comes close, reducing emissions from approximately 27 million tonnes of CO_2 equivalent in 2024 to 1.4 million tonnes of CO_2.

2.3.1 Emissions Intensity by Zone

Emissions intensity refers to the average emissions per unit of generation, as shown in Figure 14. Madrid is the region that is most challenging to decarbonize due to its limited space, high demand, and inland location, making it difficult to deploy renewables and unsuitable for CCS. Traditional industrial regions, located in smaller autonomous communities, also face challenges due to limited potential for renewable deployment.

By 2050, the Progressive and Pioneering scenarios achieve net zero emissions. The Lower Carbon scenario has some residual emissions in Andalusia. In the BAU scenario, Navarre and Extremadura are the first to decarbonize by 2050 due to their low demand and connections to neighboring countries France and Portugal, respectively.

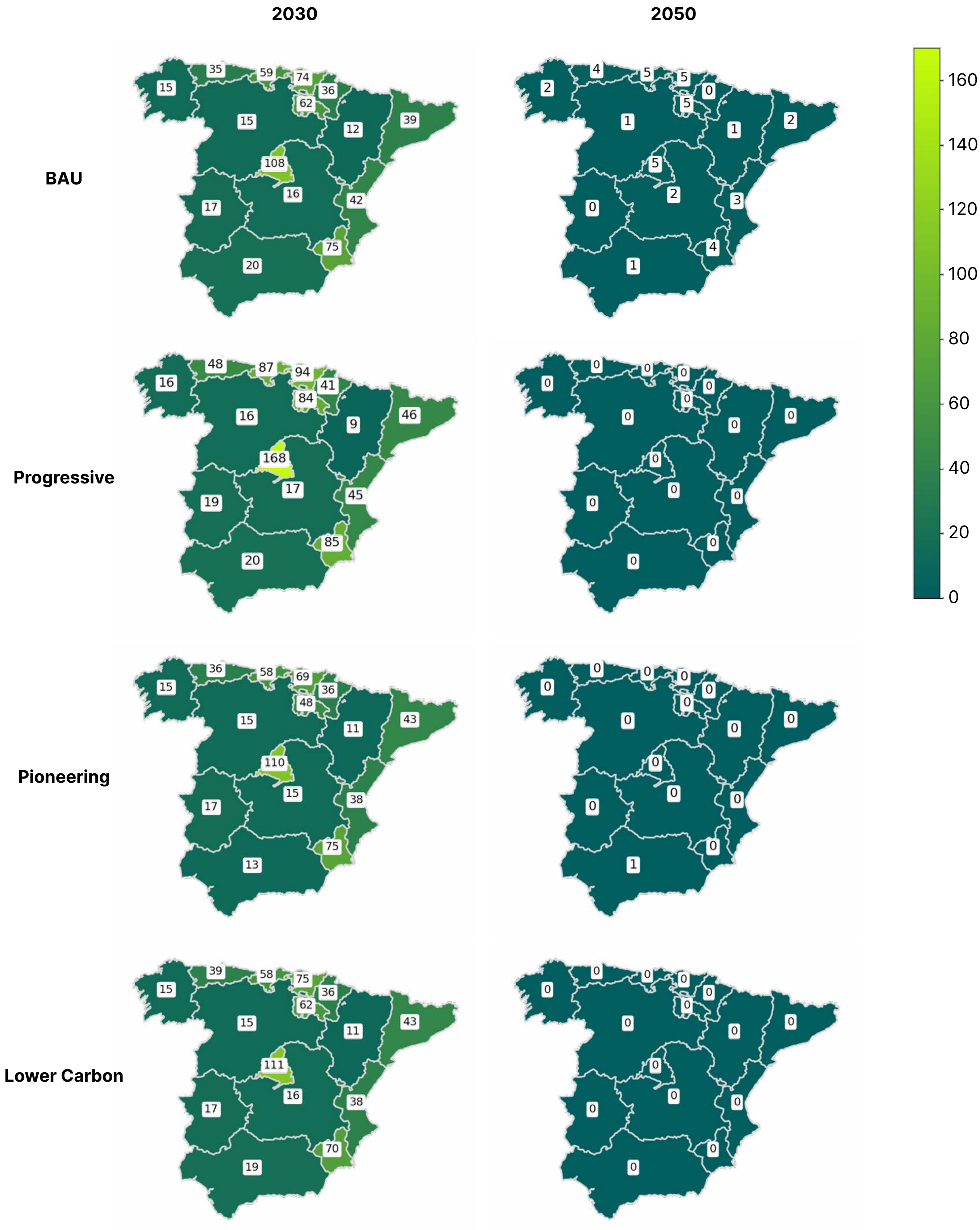


Figure 14 – Emission Intensity by Region ($kgCO_2/MWh$)

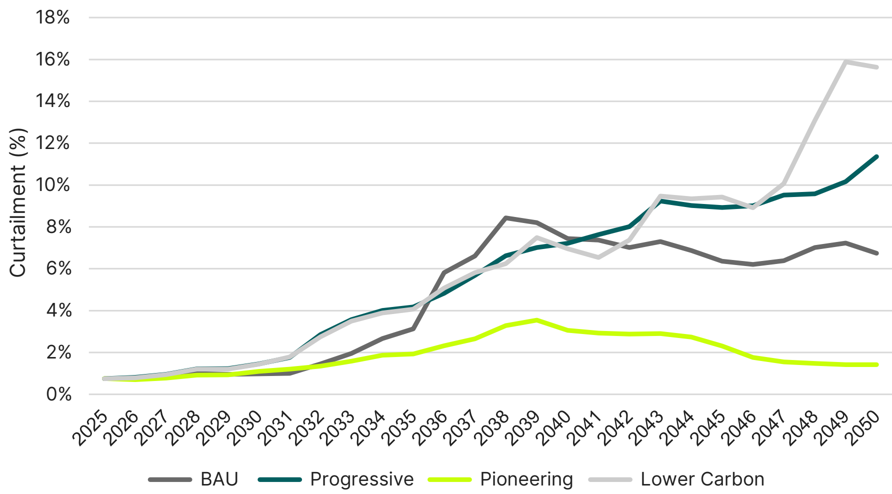


Figure 15 – Annual Curtailment of Renewable Generation

2.4 Electricity Generation Curtailment

Curtailment of renewable electricity due to excess supply over demand remains low across all scenarios until 2030, averaging around 1% of total renewable generation. This indicates sufficient system flexibility and moderate renewable penetration in the early years. After 2030, differences between scenarios begin to emerge between the scenarios with lower renewable capacity.

The Pioneering scenario results in the lowest level of curtailment across the horizon, never exceeding 4% and even declining to 1% by 2050. These results suggest that technological diversity and system flexibility are key to minimising curtailment. Scenarios incorporating dispatchable low-carbon resources (such as SMRs) and balanced renewable portfolios (as in the Pioneering case) appear to achieve greater integration efficiency under the modeled assumptions than those relying exclusively on variable renewables, as seen in the Lower Carbon scenario.

2.4.1 Curtailment by Region

Building on the national curtailment trends, regional patterns reveal where integration challenges and storage opportunities are most pronounced. Curtailment remains minimal across all regions until 2030, then rises in areas with the highest renewable penetration, reflecting growing imbalances between generation and demand at the local level.

The regional curtailment for 2050 is shown in Figure 16, overall, southern and central Spain — especially Andalucía, Castilla-La Mancha, Aragón, and Murcia — emerge as both curtailment hotspots and strategic locations for future storage and grid reinforcement.

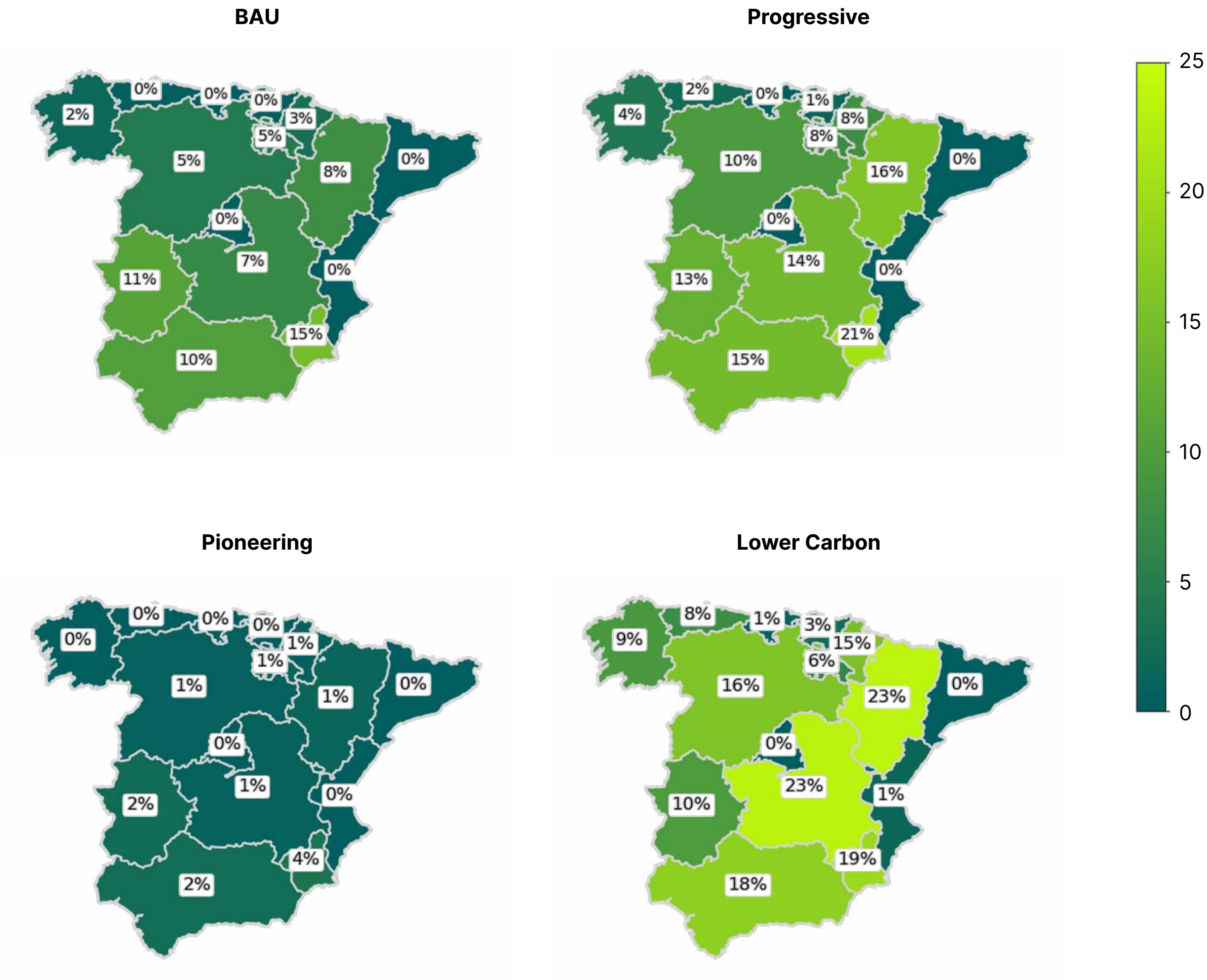


Figure 16 – Curtailment (%) by Region in 2050

2.5 Total System Cost

The total system cost, which includes capital, operational, and emissions components, evolves differently across scenarios as the system transitions from thermal-based to low-carbon generation:

- **Generation Operating Cost:** in the early years (2025-2035), the BAU scenario exhibits the highest generation costs due to sustained use of gas turbines and exposure to fossil fuel price volatility. On the contrary, in the Pioneering scenario, generation costs increase sharply toward 2045-2050, driven by high operating and fuel costs of hydrogen and CCS.
- **Emissions Cost:** they are a major differentiator. The BAU scenario faces the steepest cumulative emissions expenditure due to its fossil-fuel-intensive mix. The three remaining scenarios eliminate all emissions-related costs by 2050.
- **Generation Fixed Cost and Equity Evolution:** fixed costs follow a nearly parallel trend across all scenarios, with gradual increases due to expanding renewable and nuclear capacity. Equity, meanwhile, diverges significantly, peaking in 2040-2050 for the Lower Carbon and Pioneering cases as these systems invest heavily in green hydrogen production, storage, SMRs, and offshore wind infrastructure.
- **H_2 Operating and Equity Cost:** Costs related to the production of hydrogen for use in electricity generation through electrolysis. These only apply to the Pioneering and Lower Carbon scenarios and reach almost similar values by the period of 2046-2050.

The equity costs represent the annualized capital costs associated with equity financing of generation assets. These costs go beyond overnight CAPEX by accounting for the time value of money, investor return requirements, and asset lifetimes, thereby reflecting the full economic cost of deploying new capacity

Ultimately, evaluating the trade-off between CAPEX and OPEX distribution enables decision-makers to identify the most resilient and affordable generation mix. For Spain, this means pairing large-scale renewables with dispatchable low-carbon capacity and targeted storage investment to ensure reliability, cost-effectiveness, and full decarbonization by 2050.

2.5.1 Cost of Curtailment

The curtailed energy will have a value based on its lost sales in the energy market. Renewable generators will look to recover this lost revenue either through bidding behavior in the real-time markets. The potential annual cost of this curtailment ranges from €5m to €45m, as shown in Figure 18. The Pioneering scenario has the highest costs as marginal electricity prices will be the highest due to the increased level of thermal power plant on the system even though curtailment is at the lowest and conversely the Lower Carbon scenario has the lowest costs as marginal electricity prices are the lowest in this scenario.

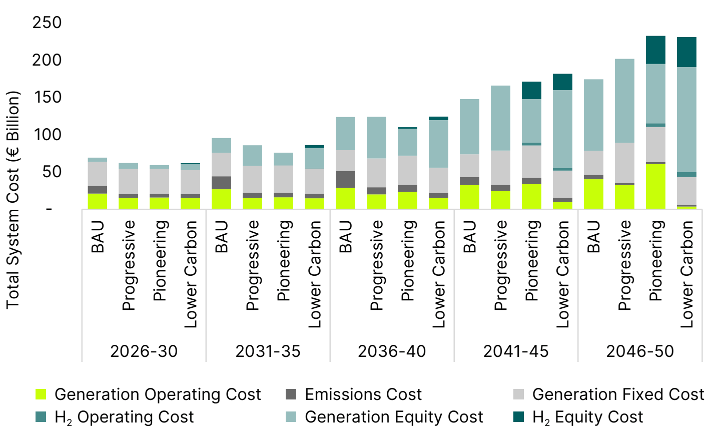


Figure 17 – Total System Cost (nominal) per five-year period

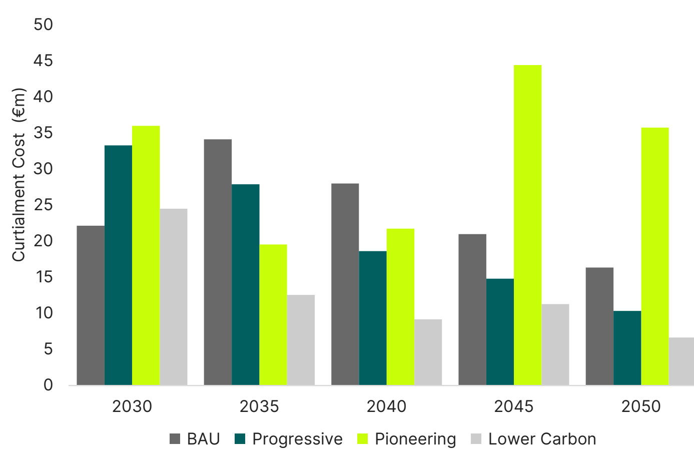


Figure 18 – Annual curtailment energy value (€m)

3. TRANSMISSION PATHWAYS TO NET ZERO

Achieving net zero in Spain will require investment in the transmission grid as well as generation. In this section, we identify the challenges that the network operators will face in the future given the previously identified generation pathways to net zero.

3.1.1 System Stability

Spain's Transmission System Operator (TSO), Red Eléctrica de España (REE), is responsible for procuring and managing ancillary services to ensure system reliability, frequency stability, and secure grid operation. As the share of variable renewable energy — including onshore wind, offshore wind, and solar PV — increases, these services become increasingly important to balance real-time supply–demand mismatches and maintain system frequency at 50 Hz.

Figure 19 illustrates the hourly penetration of renewable generation and associated curtailment for snapshot years 2035 across scenarios. Renewable generation is high across all scenarios, although it does not reach 100% in any scenario, as frequency restoration requirements necessitate a minimum level of thermal generation to remain online, providing inertia and system reserves.

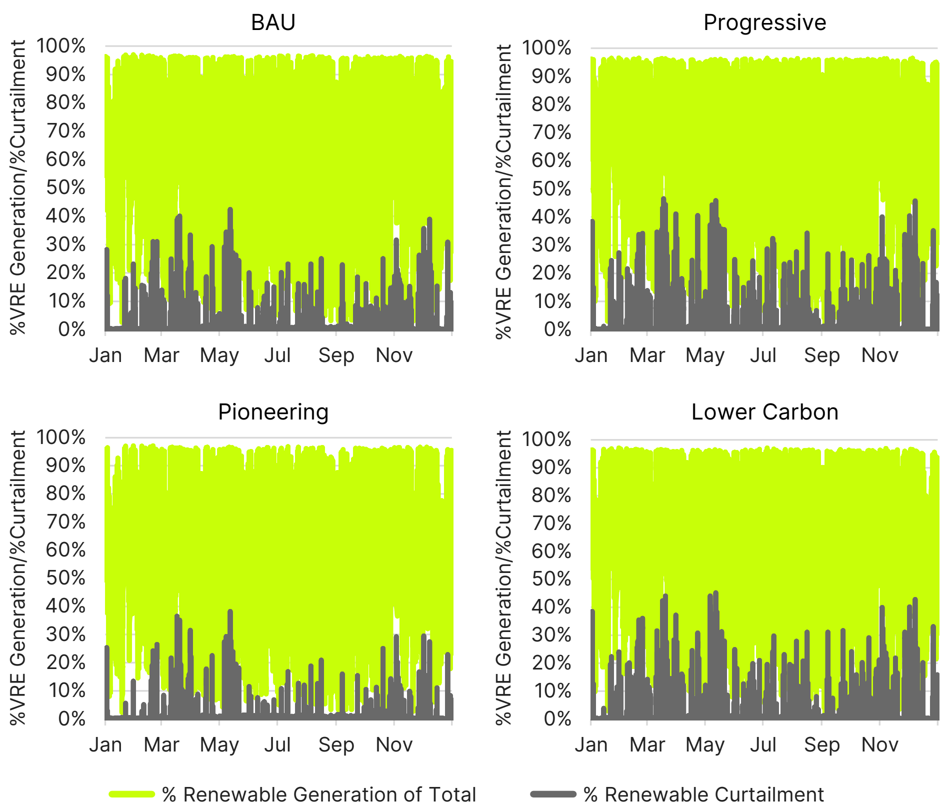


Figure 19 – Annual curtailment energy value (€m)

These results highlight the growing challenge of frequency control in a highly renewable power system. As conventional synchronous generation is progressively displaced, system inertia declines, And subsystem frequency reacts more rapidly to imbalances between supply and demand, narrowing response windows and increasing sensitivity to sudden outages or forecasting errors.

At the same time, higher shares of inverter-based generation introduce new dynamics in voltage control, fault response, and short-circuit strength. Stability challenges therefore shift from purely mechanical characteristics to digitally managed, power-electronics-dominated interactions. In this context, stability must be deliberately engineered through a coordinated set of mechanisms:

- **Fast frequency response,** capable of reacting within seconds to contain frequency deviations.
- **Voltage regulation and reactive power management,** particularly in areas with high inverter-based penetration.
- **Adequate reserve margins,** ensuring balancing capability during low-renewable or high-demand periods.
- **Advanced system control and real-time monitoring,** enabling predictive and corrective actions in increasingly dynamic operating conditions.

Different technologies contribute in complementary ways:

- Battery storage delivers rapid balancing, synthetic inertia, and frequency containment services.
- Renewable generators equipped with grid-forming capabilities or synthetic inertia increasingly support frequency and voltage stability.
- Flexible low-carbon thermal units remain critical during prolonged stress events, low-renewable periods, or large contingencies.
- Digitalisation of demand-side response for rapid system balancing.

3.1.2 Transmission Network Capacity

The decarbonization of the electricity generation fleet will result in a large amount of new capacity, particularly wind and solar, which will be distributed across the transmission (high voltage) and distribution (medium voltage) networks.

To examine the potential impact on the transmission network we have run a full DC load flow nodal model for Spain which includes all the substations and transmission lines of 220kV and above. All generators have been allocated to their closest substation in this model.

For future years, we need to make assumptions about where on the network the new capacity will be connected. For new thermal, nuclear and offshore wind power plants we have connected these to 400kV substations which are either logical due to location, e.g. offshore wind, or previously had a similar plant connected, e.g. CCGT or Nuclear. For wind and solar plants, we have ensured the capacity allocated in each region is consistent with the build and the plants are allocated uniformly across substations within each zone as a simplifying assumption for scenario analysis.

The model enables the simulation of power plant dispatch over the year while explicitly accounting for transmission network constraints. This allows the identification of heavily congested transmission lines and potential network reinforcement needs. We selected the Lower Carbon scenario as the case study, as it features the highest deployment of wind and solar generation and therefore represents the most challenging conditions for the transmission network.

In Figure 20, we show the congestion, in terms of the number of hours the lines are fully loaded, for the 220kV network. The network is significantly congested particularly around the urban areas, as would be expected. However, in 2035 the congestion pattern is relatively similar, which may reflect the fact that while generation is increasing, it is spread across the network and partially offset by rising demand.

The congestion of the 400kV network is shown in Figure 21. The network is relatively unconstrained, with only the cross-country lines towards Barcelona showing a higher level of congestion, which increases in 2035 as shown in Figure 22.

The relative limited change in network congestion over the next decade reflects Spain's broadly distributed renewable resources. As a result, solar and wind capacity does not need to be located at concentrated areas on the network, reducing the likelihood of significant additional loading on local 220kV networks, as increased generation is balanced by demand. In contrast, the 400kV network does show higher loading, driven by increased west-to-east power transfers as demand growth in the Barcelona region cannot be fully met by local generation.

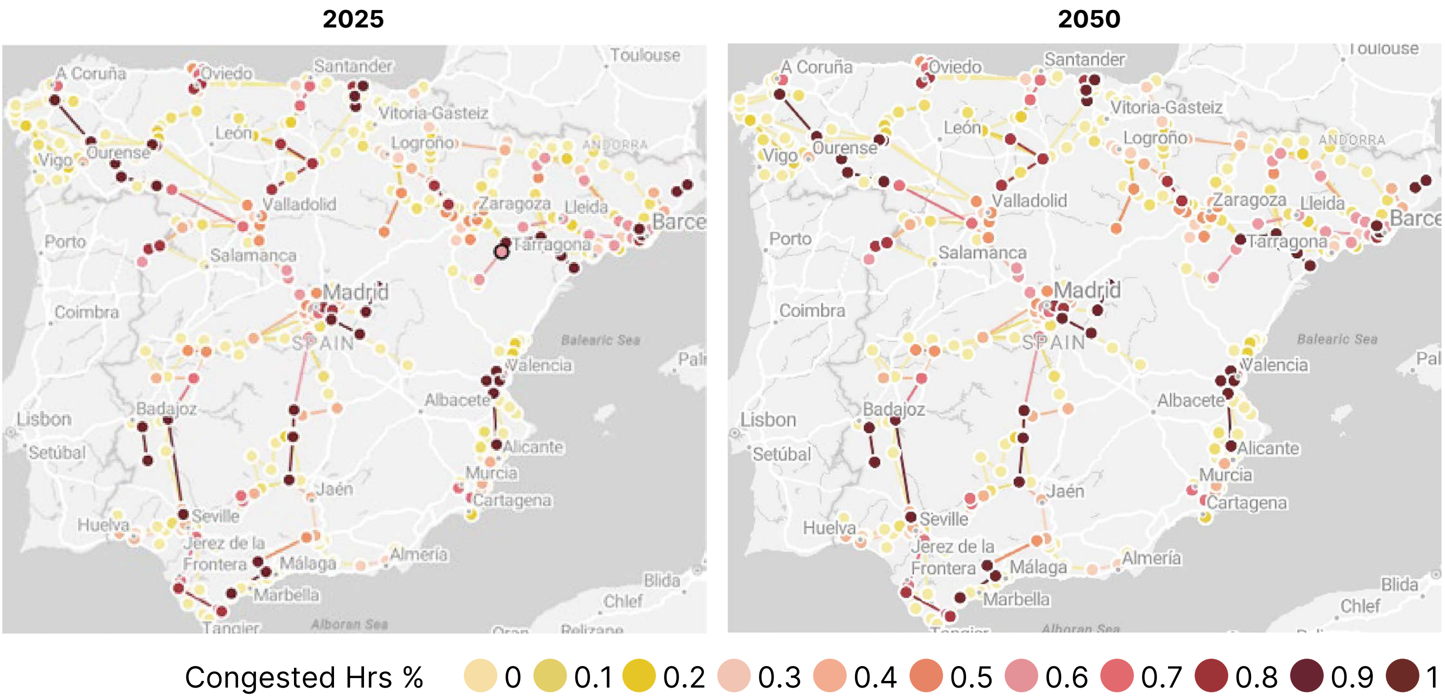


Figure 20 – 220kV Transmission Network Congestion

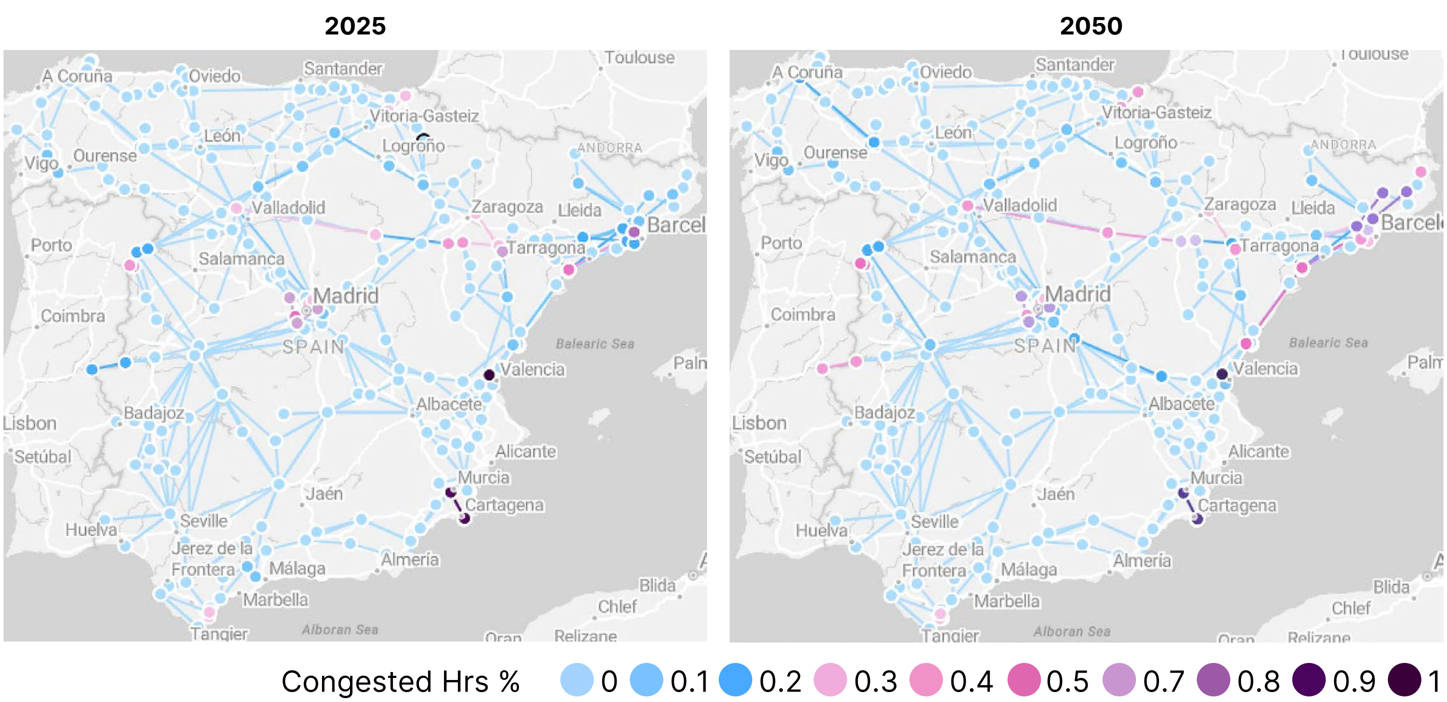


Figure 21 – 400kV Transmission Network Congestion

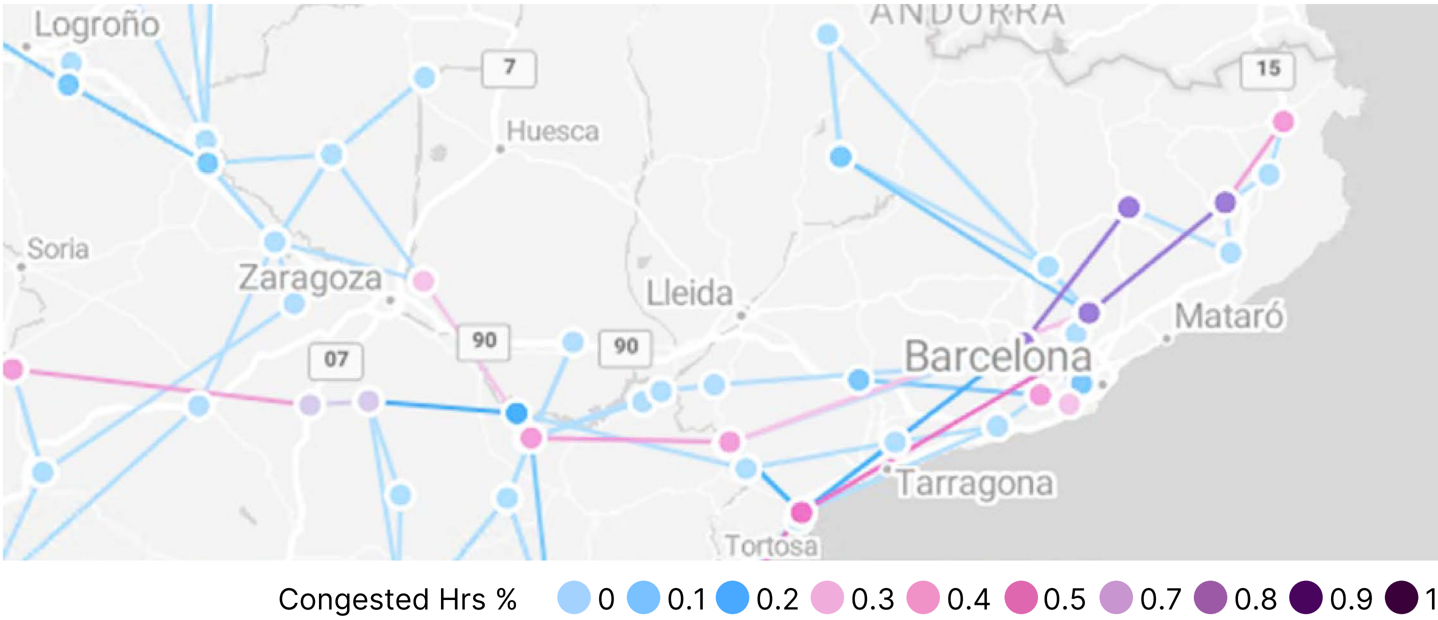
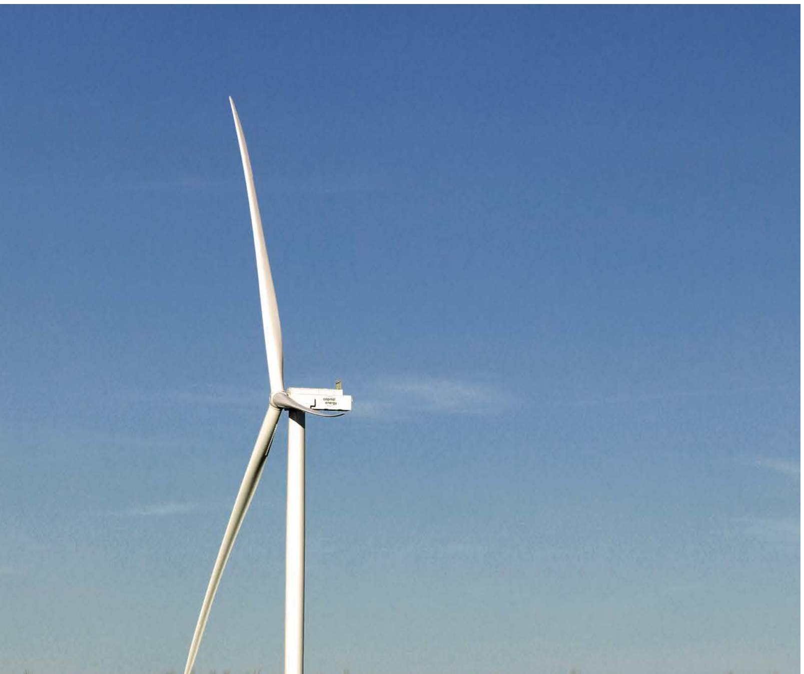


Figure 22 – 400kV Transmission Network Congestion around Barcelona in 2035

4. CONCLUSION AND RECOMMENDATIONS



The Spanish electricity system is expected to undergo a complex transition in delivering net zero by 2050 with a 60% increase in demand projected and substantial penetration of renewables generation to decarbonize the system. We draw the following insights from our detailed analysis of this transition.

4.1 Commitment to Renewable Energy

Achieving decarbonization of the Spanish electricity system requires a continued commitment to renewable energy deployment throughout the remainder of this decade. Solar PV capacity must increase by approximately 20–30% relative to 2025 levels by 2030, while onshore wind capacity needs to expand by up to 17% over the same period. These additions are consistent with recent annual deployment rates, although they remain below the capacity levels envisioned in the NECP. Delivering this volume of renewable capacity by 2030 will therefore require the continuation of existing renewable energy policies to sustain investment at the necessary pace.

Beyond 2030, the pathway to net zero is achieved through a mix of renewable and low-carbon thermal generation. Solar PV, with a relatively low capex and opex, will see the highest level of growth, followed by onshore wind. Spain's coastal waters favor floating technologies, which are associated with higher capital and operating costs.

Across the four modeled pathways, cumulative capacity additions between 2025 and 2050 range from 50% to 200% for onshore wind and from 130% to 330% for solar PV. These figures reflect renewable capacity required solely for electricity generation; scenarios characterized by lower renewable deployment and higher reliance on thermal generation operating on green hydrogen would require substantial additional renewable capacity to supply electrolysis.

Spain is well positioned to accommodate high levels of renewable generation, given its favorable wind and solar resources and extensive land availability. Historically, renewable deployment has been geographically widespread, with higher concentrations of solar PV in Extremadura and onshore wind in northern regions. Encouraging a more balanced spatial distribution of future renewable capacity could help mitigate system-level impacts, particularly on the transmission network.

Realizing this accelerated expansion of onshore wind and solar PV will require streamlined administrative processes and sustained investment incentives. Authorization procedures for higher-voltage grid connections should be simplified. In addition, the design of contracts for difference for onshore wind and solar PV may need to be revisited to better account for locational considerations, enabling deployment beyond only the highest-quality resource areas and further alleviating pressure on the transmission network.

4.2 Flexible technologies as a key enabler of delivering net zero

The increasing reliance on low-capacity-factor generation from solar PV and onshore wind, combined with limited deployment potential for higher-capacity-factor offshore wind, leads to a need for reliable and flexible generation to ensure system security. Across the modeled scenarios, differing levels of wind and solar capacity are complemented by flexible resources sized to minimize total system costs, maintain reliability during periods of low renewable output, and limit curtailment during periods of high renewable generation.

The scale and timing of this flexible capacity depend on the retirement schedule of the existing nuclear fleet. In all scenarios other than the Lower Carbon scenario, the Algeciras combined cycle power plant is retrofitted to operate with CCS, and up to 17 GW of new CCGTs with CCS are built in the model. In the Lower Carbon scenario, no new CCGTs are added; instead, over 2GW of new SMRs are deployed.

In all scenarios, system flexibility is provided by a combination of OCGTs operating on natural gas or hydrogen (in later years), and battery storage systems with both two-hour and four-hour durations. Approximately 30 GW of flexible capacity is required in the Progressive and Pioneering scenarios. In contrast, the Lower Carbon scenario, characterized by substantially higher wind and solar deployment, requires around 50 GW of battery storage to effectively integrate renewable generation.

Battery storage plays a critical role in limiting wind and solar curtailment, which remains below 10% across most scenarios. In the Lower Carbon scenario, curtailment increases modestly in the later years but remains below 16%. Lower levels of battery deployment would lead to higher curtailment and an increased risk of unmet demand.

4.3 Transmission System

The high penetration of wind and solar generation across all net-zero pathways increases the demands placed on the transmission system. System stability is challenged by the inherent variability of renewable output, requiring sufficient inertia to manage rapid frequency deviations as well as robust frequency and voltage control to maintain real-time system balance.

Ensuring system stability under these conditions will require an evolution of ancillary services markets to guarantee that adequate capacity capable of providing these services is available and committed. This includes maintaining a minimum level of synchronous thermal and hydro generation online, while also creating incentives for wind and solar plants to contribute to ancillary services provision. In addition, the development of a dedicated market for inertia would support the deployment of synthetic inertia from renewable generators, complementing the physical inertia provided by conventional synchronous units.

Compared to several other European countries, Spain benefits from relatively well-distributed renewable resources, enabling geographically dispersed deployment of wind and solar capacity and thereby moderating stress on the transmission network. While congestion is expected to increase around major demand centers, the transmission system is projected to accommodate the levels of renewable generation observed across all scenarios.

4.4 Pathway to Net Zero

Across the four net-zero pathways, total system costs are broadly comparable when accounting for both capital and operating expenditures of the electricity system, as well as the infrastructure required to produce hydrogen for power generation. The Lower Carbon scenario exhibits the highest overall cost, reflecting the substantial investment in battery storage needed to fully utilize the high levels of renewable capacity.

Overall, a balanced portfolio combining renewable generation with low-carbon thermal technologies emerges as the least-cost approach to achieving net-zero targets while maintaining system stability.

Appendix A: Key Inputs

Appendix A 1. Electricity Demand

Electricity demand for Spain's peninsula region is based on historical total electricity demand data published by the local TSO Red Eléctrica. Future projections are based on GPD forecasts and regression on historical sectorial demands sourced from Eurostat.

Demand is projected to rise significantly from current levels due to electrification of transport, heating and accelerated uptake of data centers. The EV and HP demand projection is based on the logistic function (S-shaped curve). Historical data is fitted to the function and targets where available, to estimate future growth of electric vehicles (EVs) and heat pumps (HPs). Data center demand was calculated by filling a polynomial curve to datapoints as projected by ICIS[3].

Compared to the NECP demand projections, the 2030 projections are very similar but slightly lower by 7%. This difference arises from the model focusing solely on the Spanish peninsular region, excluding Spain's islands.

Demand response and advanced control technologies, i.e. virtual power plants, are not explicitly modeled in this study. However, it is accounted for by optimizing scheduling of the additional demand from Electric Vehicles (EVs) and heat pumps – i.e. it is modeled as a uniform daily load profile, while still representing the seasonal variation which is particularly relevant for heat pumps.

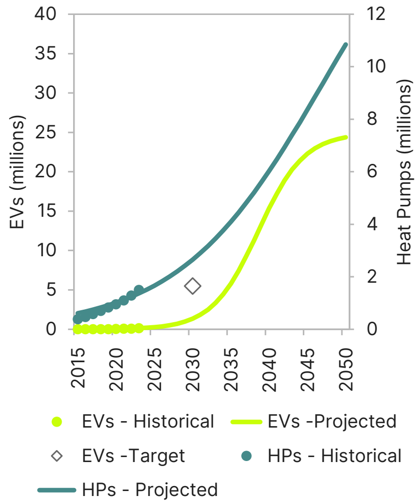


Figure 23 – Uptake of heat pumps and electric vehicles

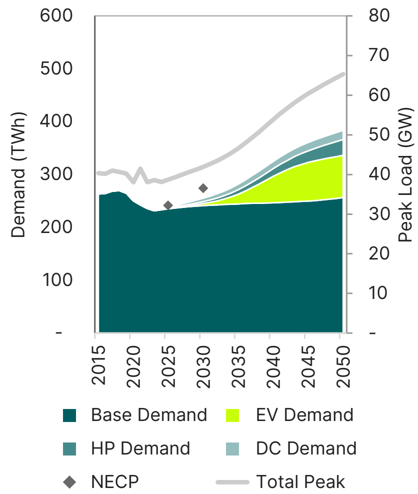


Figure 24 – Electricity demand build out in Spain Peninsula

[3] ICIS. (2024). Data centres: Hungry for power. https://www.icis.com/explore/resources/data-centres-hungry-for-power

Appendix A 2. Reserve Requirements

We model the reserve capacity holding requirements for Hydro and Thermal power plant, based on data contained within ENTSO-E's Pan-European Market Modeling Database (PEMMDB)[4]. This capacity will need to be committed at a day-ahead stage in order to be available to ramp up or down as required. Reserve requirements for thermal plant fall over time as plant retire and an increasing level of reserve is provided by batteries and renewable generators.

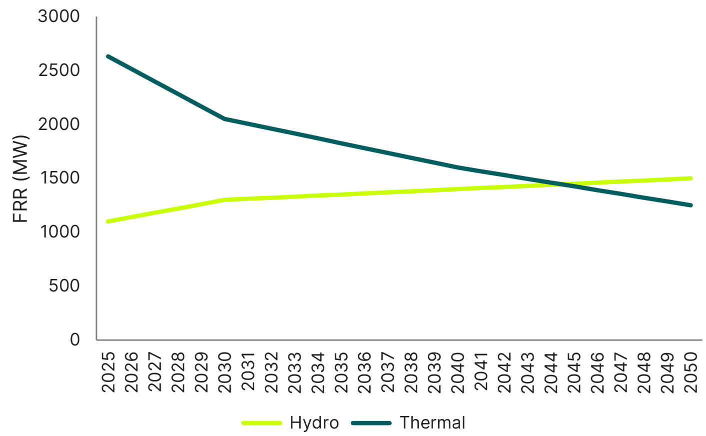


Figure 25 – Frequency restoration reserve (up and down)

Appendix A 3. Wind and Solar Representation

Renewable output profiles by zones are calculated based on hourly generation profiles for new wind and solar farms using the European Centre for Medium-Range Weather Forecasts' (ECMWF) Reanalysis v5 (ERA5) dataset[5]. This dataset provides information on wind velocity and solar irradiation across Spain, which is used along with wind turbine and PV panel configurations to calculate power generation data for each power zone. Capacity factor maps for wind farms and solar PVs are shown below, based on a historical 2021 weather year; this should be presented as a simplifying weather-year assumption rather than a full representation of interannual variability.

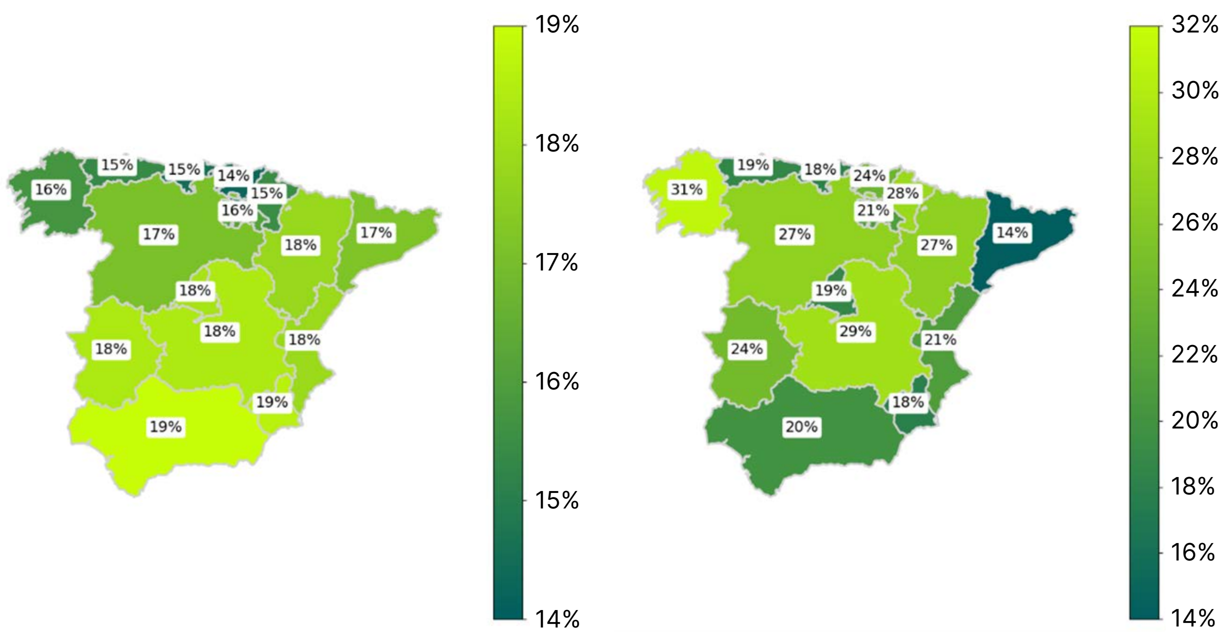


Figure 26 – Solar (Left) and Wind (Right) Regional Profiles

[4] ENTSO E, & ENTSOG. (2024). Pan European Market Modelling Database (PEMMDB2) [Dataset]. TYNDP 2024 Scenarios Input Data. https://2024-data.entsos-tyndp-scenarios.eu/files/scenarios-inputs/PEMMDB2.zip
Copernicus Climate Change Service. ERA5: ECMWF Reanalysis v5 [Dataset]. European Centre for Medium Range Weather Forecasts.

[5] ENTSO E. (2024). TYNDP 2024 Transmission Projects Map. https://tyndp2024.entsoe.eu/projects-map/transmission

Appendix A 4. Cross Border Interconnection

The 2024 ENTSO-E Ten Year Network Development Plan[6] has identified that Spain is expected to increase its interconnection capacity to enhance grid resilience and renewable integration. Red Eléctrica submitted several prospective interconnector projects, of which only those deemed sufficiently mature for inclusion in the TYNDP 2030/2035 reference grid were incorporated into our modelling framework.

Spain currently has 9.3 GW of import capacity between France, Portugal and Morocco. This is expected to increase to 13 GW by 2035 due to interconnection expansion with France as shown Table 1 below. Seasonal variations and export limits are modeled. Generally, slightly higher transmission line capacity is experienced in Winter reflecting higher thermal limits. Reduction in transfer capacities during off-peak hours is also accounted for.

Country	Current Import Capacity (MW)	Additional Import Capacity (MW)
France	3500	2200 in 2028 1500 in 2035
Portugal	5200	
Morocco	600	

Table 1 – Interconnection Capacity

Appendix B. Hydrogen Modelling

Green hydrogen represents a promising fuel source that could assist the Spanish electricity system in achieving net-zero emissions. Green hydrogen is generated through the process of electrolysis, utilizing renewable energy sources as the electricity feed. In our analysis, to ascertain the capacity of onshore wind, offshore wind and solar PV dedicated to green hydrogen production, as well as the capacity of the electrolyzers themselves, an in-house hydrogen model was developed. For simplicity, the green hydrogen system was modeled independently from the electricity system; this should be treated as a simplifying assumption when interpreting the results. This approach also complies with EU regulations, which mandate that green hydrogen produced after 2030 must originate from new renewable sources with guarantees of origin.

The hydrogen model assumed the use of PEM (Proton Exchange Membrane) electrolyzers coupled with variable renewables. The model utilizes hourly renewable output profiles that are identical to those inputted into the electricity system model. This approach allows the model to capture the impact of renewable availability on the electrolyzer capacity factor. An electrolyzer efficiency of 70%, including auxiliary use, is assumed. Additionally, the model incorporates the costs associated with the consumption of deionized water and cooling water required for the electrolysis process.

The CAPEX and OPEX assumptions are outlined in the figure below. Notably, stack replacement costs are included in the model, with replacements occurring every 15 years.

The hydrogen model is designed to determine the optimal combination of wind (onshore and offshore) and solar capacities to electrolyzer capacity that is able to meet the required hydrogen demand, which is an output of the electricity market model. The primary objective of the model is to minimize the levelized cost of hydrogen.

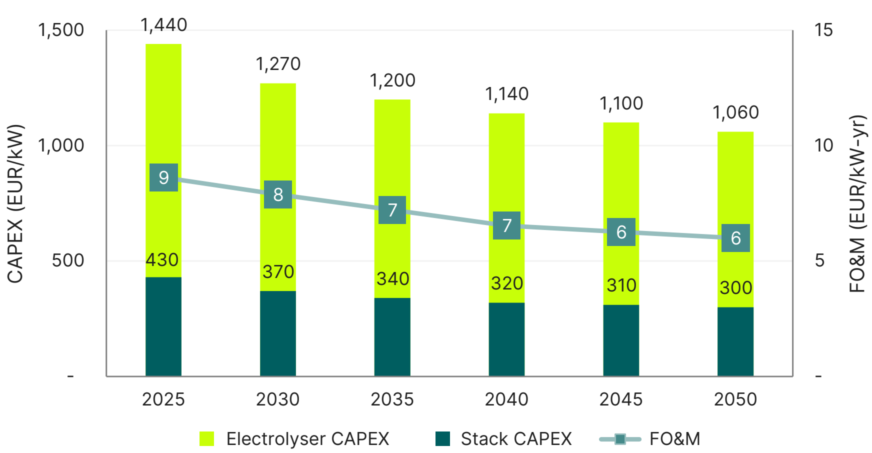


Figure 27 – PEM Electrolyzer Costs

[6] S&P Global Commodity Insights. (2025). Electrolyzer Capital Expense Model — V3.0

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