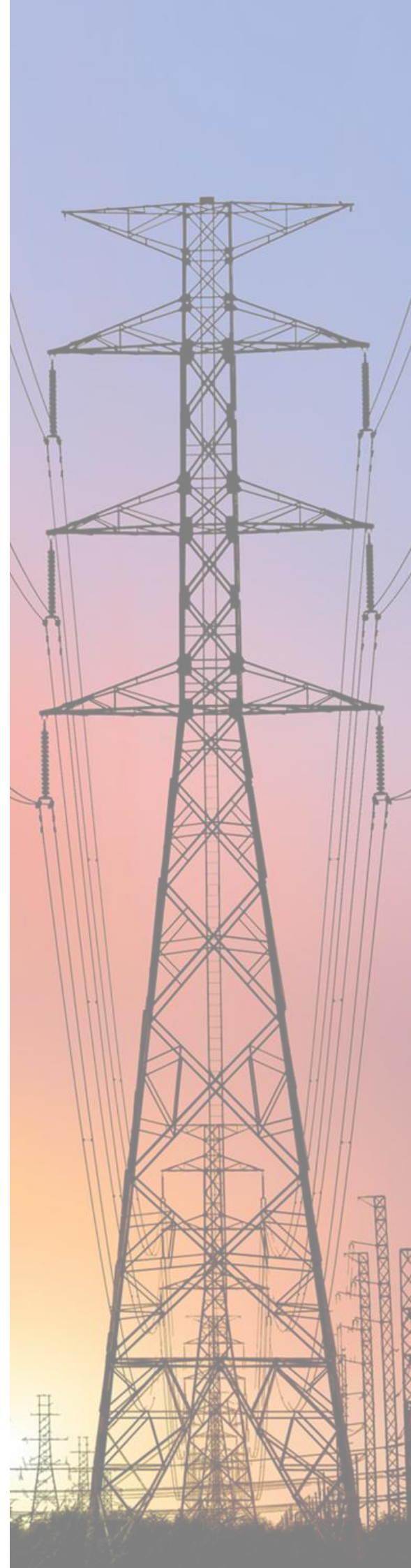


Report Commissioned by SFEN

The role of the French nuclear fleet within European integrated power markets

March 2026



Executive summary

Europe's electricity sector is undergoing structural transformations that have increased public interest in power-system economics

Since the late 1990s, successive European energy packages have liberalised electricity markets and expanded cross-border exchanges, progressively integrating national systems into a unified Internal Electricity Market. Over the same period, the generation mix has strongly decarbonised, with rapid growth in wind and solar complementing existing low-carbon technologies such as nuclear and hydropower. While this transition supports climate objectives, it also brings new operational and economic challenges, as variable renewable generation increases supply volatility and can place pressure on historical baseload technologies. At the same time, greater volatility in wholesale power prices, amplified by shocks such as the 2021–2022 gas crisis, has heightened uncertainty and revealed consumer exposure to wholesale markets. In France, the end of the regulated nuclear access scheme (ARENH) also increases nuclear volumes traded on these markets. Together, these developments have sparked growing interest in understanding France's position within the integrated European electricity market and the role of nuclear power in current market dynamics.

The study relies on Aurora's dispatch model to illustrate current market dynamics and capture the impact of key system variables

Commissioned by SFEN, the study uses Aurora's Origin model to analyse short-term system operation and day-ahead market outcomes for 2026 across sensitivities to weather conditions, commodity prices (gas and carbon), and nuclear availability. The approach is deliberately descriptive and educational: it does not capture all system contingencies or provide a full technical assessment of system security, and should not be interpreted as a prediction of 2026 outcomes, which will ultimately depend on real-world market and meteorological conditions. The analysis characterises current market dynamics in France and its neighbouring regions, quantifying the economic, environmental, and adequacy implications associated with the sensitivities explored.

In the current market design, dispatch and prices are driven by simple economic principles that shape electricity generation and cross-border flows

In the day-ahead market, two main principles determine dispatch and price formation: merit-order ranking and marginal pricing. Power plants are ranked from the cheapest to the most expensive to run, and the cheaper ones are used first. All selected generators are remunerated at the price of the last and most expensive unit needed to meet demand. Cross-border market coupling extends this logic across interconnected bidding zones. When interconnectors are not congested, generation is dispatched in a regionally optimal way and prices tend to align. When congestion occurs, price spreads emerge between countries, reflecting cost advantages and remaining opportunities to improve system efficiency. This integration brings proven benefits at European scale: it improves the use of low-cost generation,

reduces overall system costs, strengthens adequacy, supports renewable integration, and lowers carbon emissions.

France's geographic position and power mix make it a net contributor to regional affordability and decarbonisation

Its central location and extensive interconnections with neighbouring zones make it a key player in the integrated market. Because cross-border flows follow price differentials, France's low marginal cost fleet drives frequent exports to higher-priced regions. This competitiveness translates into net annual exports of 86 TWh for 2026 (compared with 92 TWh observed in practice in 2025). Given the highly decarbonised nature of the French generation mix, these exports also contribute to lowering carbon emissions in importing countries. However, this net position should not mask the hour-by-hour dynamics of economic efficiency as price spreads frequently reverse. There is strong complementarity between the French generation mix and those of its neighbours. Integration shares and amplifies the benefits of low-carbon technologies.

The nuclear fleet is central to France's competitive and low-carbon power system

When nuclear output declines, the system relies more heavily on more expensive and carbon-intensive technologies, increasing both prices and emissions. France is particularly exposed to such shocks: a drop in nuclear output similar to that observed in 2022 would raise average domestic power prices by more than 15€/MWh. But the impact extends beyond its borders, with neighbouring countries experiencing price increases of 1 to 6 €/MWh and higher emissions as fossil generation substitutes for nuclear. Overall, reduced nuclear availability, or capacity, leads to higher generation costs (+2%), consumer costs (+8%), and carbon emissions (+8%), underscoring the importance of maintaining strong nuclear generation within the current system.

Through its presence in the marginal mix, nuclear power also acts as a partial buffer against volatile commodity costs

Strong output from variable renewables and nuclear power, both located at the bottom of the merit order, reduces reliance on higher-cost fossil-fired units. However, within the market design a country's generation mix alone does not determine its power prices, what ultimately matters is which technologies set the price and how frequently they do so. Within the marginal mix, technologies higher in the merit order, such as gas-fired and storage units, are disproportionately represented relative to their share of total generation. Fossil-fuel-based technologies (mostly gas) directly set prices 36% of the time, and their influence extends to up to 66% of hours when accounting for storage technologies whose bidding strategy is linked to fuel and carbon prices. This poses a risk for power prices, as these technologies remain highly sensitive to fossil fuel volatility. A price-resilient power system is therefore one in which the marginal mix is less exposed to commodity price fluctuations. By contrast, nuclear and variable renewables have largely gas-insensitive variable costs. In France, these technologies,

predominantly nuclear, set prices roughly 25% of the time, translating into greater resilience to commodity price shocks than in most other countries studied.

Meteorological extremes tighten the supply–demand balance, driving higher prices and carbon intensity

Stress events capture system behaviour when the balance between supply and demand is most constrained. They are driven by extreme meteorological conditions, either demand-driven like cold spells leading to sustained high consumption or supply-driven like *dunkelflaute* episodes with very low wind and solar output. Their occurrence is highly seasonal, concentrated in winter, and can span several days to weeks. These events are often spatially correlated across Western Europe, limiting the ability of neighbouring systems to provide support through interconnections. Across the eleven historical weather years analysed, such events represent recurring sources of price and carbon stress, with average electricity prices typically exceeding 100 €/MWh and carbon emissions increasing by more than 50% compared to annual averages. Two representative cases are detailed: the February 2012 cold spell and the December 2006 *dunkelflaute*, both applied to the 2026 power system.

During stress events, market clearing shifts to the upper end of the merit order, with nuclear having only an indirect effect on prices

The need for dispatchable generation increases sharply during stress events, pushing market clearing further up the merit order. In France, nuclear plants operate at full available capacity and act as baseload, while higher-cost technologies, primarily fossil-fired and storage units, become price-setting, as in other regions. As a result, nuclear no longer shields prices from fuel and carbon volatility, and French prices respond to commodity shocks much like those in neighbouring countries. Even so, when supply is scarcest, nuclear power still helps contain prices by limiting the use of the most expensive units, either domestically or abroad depending on flow direction. This benefit depends heavily on nuclear available capacity: reduced output significantly amplifies price increases, especially during the cold spell event, where France shift from a net exporter to a net importer. Under reduced nuclear availability, average event prices rise by up to 67% compared with the central scenario.

Carbon intensity increases significantly during stress events, and dispatchable nuclear generation ensures regional emissions remain contained

Stress events increase emissions because additional demand is met by fossil-fired generation. Therefore, each MWh of low-carbon output directly displaces a fossil one. Nuclear capacity is especially important in these situations, providing dispatchable low-carbon electricity at high load factors when it is most needed. When nuclear output falls, emissions rise, by 8% during the *dunkelflaute* event and 11% during the cold spell across the six countries studied. The nuclear fleet ensures carbon intensity is contained in such situations.

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1. Context and objectives

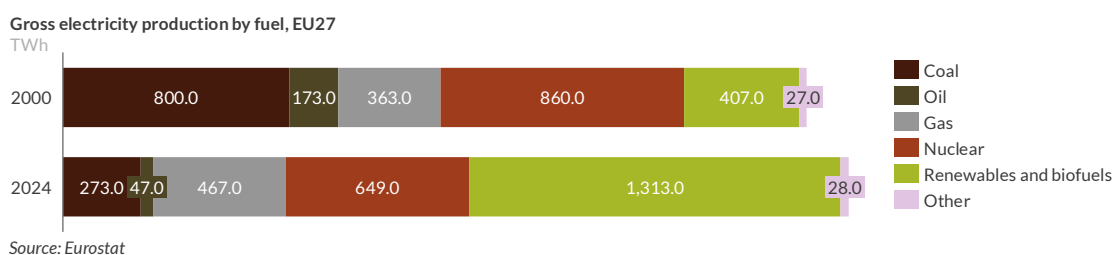
1.1. Context

Since the adoption of the First Energy Package in the late 1990s, European legislation has progressively laid the foundations for a liberalised and integrated electricity system. Successive directives and regulations have enabled multiple generators, suppliers and other market participants to operate both within and across national borders, facilitating competition, ensuring non-discriminatory network access, and promoting efficient price formation within the Internal Electricity Market¹. Integration is progressing through the incremental harmonisation of market rules, extending beyond day-ahead and intraday markets to include ancillary services and balancing².

Over the same period, the European power system has gradually evolved toward a more diversified and decarbonised generation mix. Historically, low-carbon electricity was provided by nuclear and hydropower, while fossil-fuel-based plants

supplied the rest of the generation. Over the past twenty-five years, renewable sources, particularly wind and solar, have expanded rapidly, driving the decarbonisation of the power sector alongside the progressive phase-out of coal- and oil-fired assets. As a result, the carbon intensity of electricity production has declined steadily, and the contribution of low-carbon technologies in the EU power system has increased significantly. In 2024, low-carbon sources accounted for more than 70% of gross electricity generation, while fossil fuels represented 28%, with gas-fired generation being the only fossil technology whose output has increased since 2000. With the launch of the European Green Deal and, more specifically, the revision of the Renewable Energy Directive³, the EU has reaffirmed these ambitions by establishing a binding target for renewable energy to reach at least 42.5% of final energy consumption by 2030.

Figure 1 - Strong renewable energy expansion over the past 25 years has supported the progressive phase-out of coal and oil generation



While this decarbonisation progress is positive from a climate perspective, the resulting evolution in the generation mix raises operational and economic challenges.

The growing share of **variable renewable energy (VRE) sources** introduces additional variability and forecast uncertainty in electricity supply, increasing the need for

¹ Directive 96/92/EC, Directive 2009/72/EC; Regulation (EU) 2019/943 on the Internal Electricity Market

² This process is operationalised through common European platforms, including SDAC, SIDC, PICASSO, MARI coordinated by European Transmission System Operators (TSOs) and Nominated Electricity Market Operators (NEMOs)

³ Renewable Energy Directive III, Directive (EU) 2023/2413

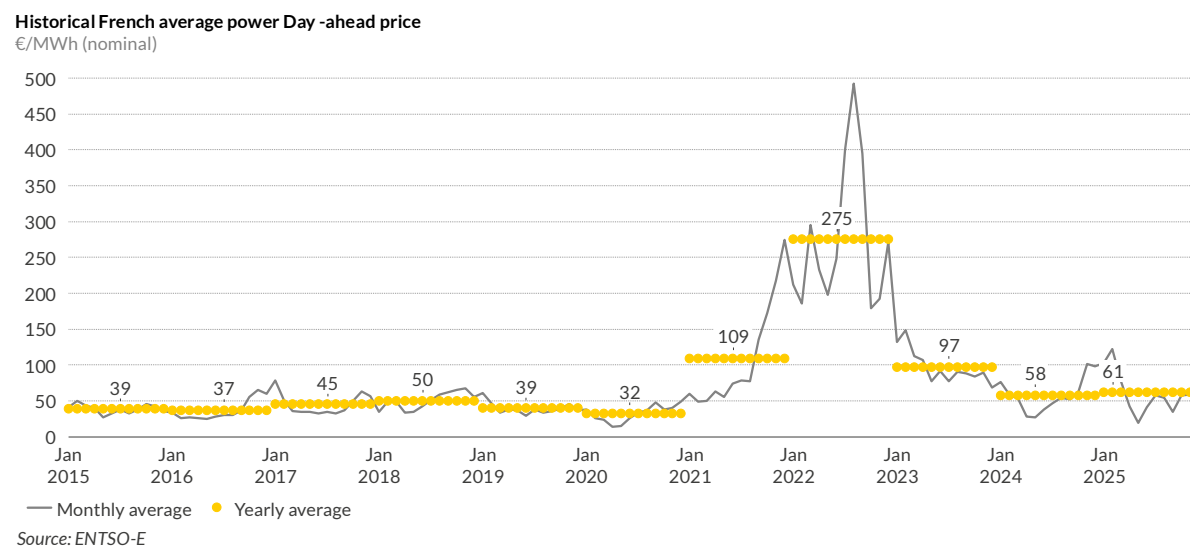
flexible resources and reinforced regional coordination to ensure continuous system balance. This coordination becomes even more critical as periods of renewable surplus generation grow more frequent. Such episodes can depress wholesale prices, place economic pressure on traditionally baseload technologies that were designed to operate at high-capacity factors and lead to curtailment⁴. These dynamics have specific implications for France’s system, given its supply structure: strong nuclear fleet, combined with expanding renewable capacity, already drive record export volumes as production growth outpaces demand⁵.

Alongside changes in market structure and generation mix, consumers have become increasingly exposed to wholesale market dynamics. External shocks have shown the sensitivity of electricity prices to fuel supply conditions and geopolitical risks. In particular, the 2021–2022 gas supply disruptions following Russia’s invasion of

Ukraine has highlighted the role of gas-fired generation in price formation. This event, together with low nuclear and hydro availability, contributed to exceptionally high wholesale prices, with French baseload⁶ reaching 275 €/MWh in 2022, with direct consequences for consumer costs⁷. In addition, the scheduled end of the *Accès Régulé à l’Électricité Nucléaire Historique* (ARENH) mechanism in 2026, together with ongoing discussions regarding frameworks for existing nuclear capacity, indicates that nuclear generation will be increasingly sold through wholesale markets, a change that should further expose French consumers to wholesale prices^{8,9}.

These combined developments have increased the importance of understanding France’s position within the integrated European electricity market and the specific role of nuclear power in current system dynamics.

Figure 2 - Evolution of the French day-ahead price over the past 10 years



⁴ Deliberate reduction or shutdown of available generation, typically VRE generation

⁵ RTE (Réseau de Transport d’Electricité). Bilan prévisionnel. Edition 2025

⁶ Simple average of hourly Day-ahead market price

⁷ ACER (Agency for the Cooperation of Energy Regulators). Electricity Wholesale Market Report. 2023

⁸ CRE (Commission de régulation de l’énergie), Évaluation des coûts complets de production de l’électricité au moyen des centrales électronucléaires historiques pour la période 2026-2028, 22 septembre 2025

⁹ Even customers under the regulated tariff (TRV), though shielded from spot-market volatility, still face indirect exposure to wholesale prices through long-term market electricity sourcing.

1.2. Study objectives

In this context, SFEN has commissioned Aurora Energy Research to conduct a study addressing the interaction between the French electricity mix, particularly nuclear generation, and the interconnected power system in Western Europe. The study focuses on three central questions:

- **What mechanisms coordinate the dispatch of generation and cross-border power flows in European electricity markets, and how do these mechanisms account for physical system constraints?**
- **What is the contribution of the French electricity mix to system security, power affordability, and CO₂ emissions reduction at the regional level, particularly in neighbouring countries?**
- **What specific role does nuclear power play during periods of supply-demand stress, such as peak demand**

1.3. Scope

The study investigates the operational contribution of the French electricity mix to the interconnected Western European power system using Aurora's Origin market model. The analysis focuses on short-term system operation and day-ahead market outcomes under current structural conditions.

The modelling is performed for the year 2026 based on Aurora's central scenario assumptions to minimise the hypotheses on structural parameters such as the power system generation units, the demand or the prices of commodities. Using a simulation approach allows the isolation of the principal drivers of market dynamics. The system is simulated under a range of weather, commodity, nuclear, and interconnector availability conditions detailed in the methodology section.

or sustained episodes of low renewable generation?

The report is designed to be educational and accessible to a wide audience, including non-specialist stakeholders. To that end, it begins with an overview of the current European electricity market design (section 3), followed by an analysis of recurring seasonal and intraday market dynamics (section 4). It then assesses system responses during supply-demand stress conditions driven by meteorological variability and operational constraints (section 5).

Aurora Energy Research applies a technology-agnostic and neutral approach, and the results presented reflect the outcomes of the modelling framework under the scenarios and assumptions defined in the following section.

The study covers France and selected neighbouring regions relevant to its cross-border market interactions (Germany, Belgium, Great Britain, Spain, and Northern Italy). However, the modelling includes a wider European perimeter as described in the modelling framework. Results are interpreted at monthly, daily, and hourly granularities.

Stress events are identified based on extremes in demand and generation. Two categories of events are examined in detail: sustained low renewable output (*Dunkeflaute*) and sustained high demand. For each case, the study analyses observed market behaviour and system response through economic, operational, and environmental indicators.

1.4. Limitations

While the analysis provides insights into system behaviour and cross-border interactions, several aspects fall outside its scope:

1. First, the study is descriptive in nature and not intended as a comprehensive literature review. It does not seek to exhaustively cover the academic research on power markets operations, nor to model all potential operational contingencies across the entire interconnected system. Doing so would require substantially broader analytical scope and computational resources and would undermine the report's clarity and educational purpose. The focus is therefore placed on illustrating key mechanisms and system behaviours using representative and transparent modelling outputs.
2. Second, the study does not address long-term investment frameworks or cost-recovery mechanisms for nuclear or any other generation technology (e.g., CfDs, regulated remuneration, fleet refurbishment costs). The analysis focuses on observed system interactions and dispatch patterns based on existing market rules and technological mix, rather than on future investment decisions. Similarly, the report the study does not estimate retail or industrial electricity bill impacts.
3. Third, the study does not seek to provide a full assessment of power system security in the technical sense. Issues such as internal grid congestion, voltage stability, inertia, and detailed frequency control are not modelled; real-time balancing and ancillary services are discussed only in a qualitative manner to contextualise their relationship to day-ahead market outcomes.
4. Fourth, although a significant share of electricity is traded through forward and long-term contracts, the day-ahead market price is used as the reference price as it remains the standard indicator of short-term power system valuation.
5. Fifth, the results should not be regarded as exact forecasts of 2026 outcomes. Realised spot prices and dispatch will inevitably differ due to changes in weather conditions, demand fluctuations, fuel and carbon price movements, and other unforeseen operational uncertainties.

2. Modelling framework

2.1. Aurora's origin model overview

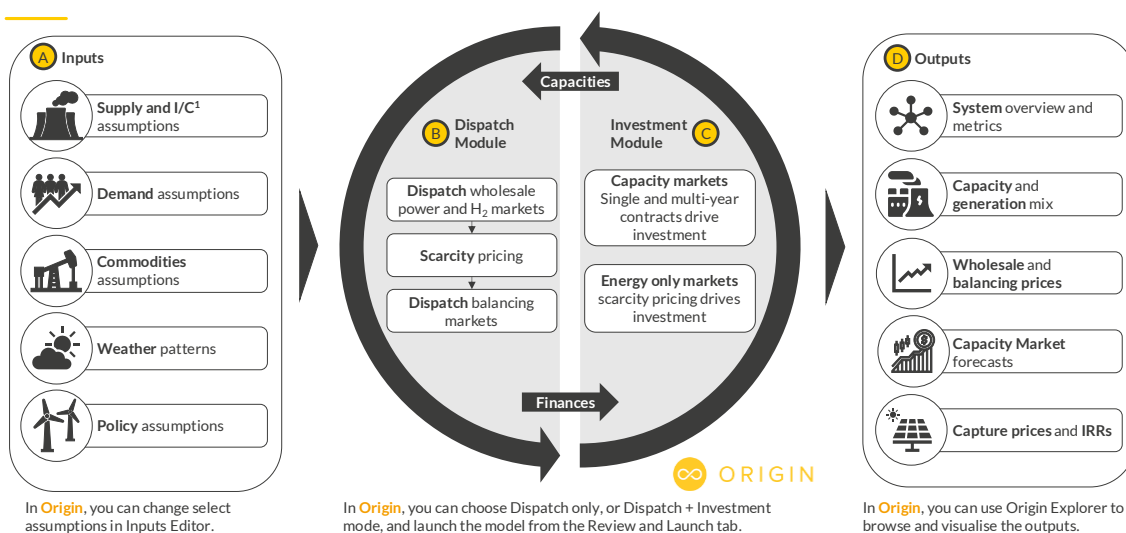
Aurora's Origin tool is an hourly dispatch and power market simulation model that represents the physical and economic operation of interconnected electricity systems. Within each bidding zone, it applies a copper-plate assumption, meaning that no internal transmission constraints are modelled and each zone clears as a single node. However, cross-border interconnections between zones are explicitly represented, with flows determined by available transfer capacities.

Although the results presented in this report focus on six price zones, the model includes the entire European power system. All interconnected countries are simulated simultaneously, ensuring that price formation, dispatch decisions, and cross-border exchanges reflect European dynamics.

The model optimises generator dispatch and cross-border flows based on a large set of technical and economic parameters including fixed and variable costs, demand, generation availability, and interconnector capacities. The model simulates day-ahead market clearing, producing price formation, generation mixes, and interregional power exchanges. It is fully calibrated and continuously updated by our local teams to reflect latest system developments.

It forms the analytical foundation of Aurora's long-term market outlooks, used across the energy sector by project developers, utilities, large consumers, financial institutions, and regulatory bodies to support investment, portfolio, and policy decisions worldwide.

Figure 3 - Display of Aurora Origin's model input and output parameters



¹ Interconnector capacity.

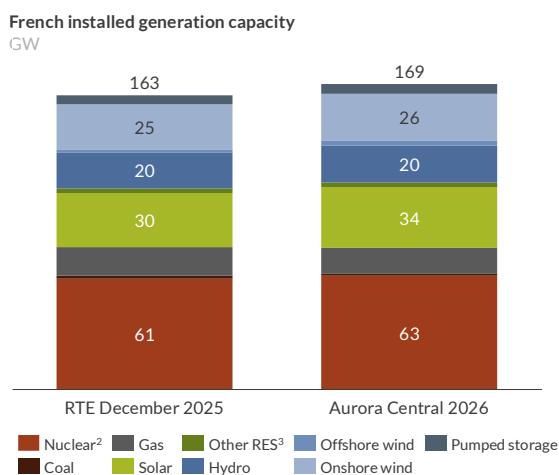
2.2. Reference assumptions

In this study, the European power system is simulated for the year 2026 using the dispatch module only, with generation capacities treated as exogenous inputs. The capacity assumptions are based on Aurora’s Central Scenario published in October 2025, which incorporates near-term developments while remaining broadly

aligned with the current system configuration.

Relative to RTE’s 2025 installed capacity inventory¹⁰, the main differences in the scenario include the inclusion of the new unit at the Flamanville nuclear power plant, the addition of 2GW of onshore wind and 5GW of solar PV capacity.

Figure 4 - Reference assumption for 2026 central simulations across demand, capacity, commodity prices and weather patterns



	Historical - 2025	Simulation - 2026
French power demand	449TWh	461TWh
Gas price	37.6€/MWh	30.3€/MWh
Carbon price	69.62€/tCO2	77.9€/tCO2
Weather patterns		Reference weather year (2013)

2.3. Scenario design

To analyse system operation under varying structural and meteorological conditions, the study applies a set of scenario variants around a central 2026 case. These scenarios are not intended to forecast long-term structural evolution; rather, they are

designed to test how power system dynamics respond to credible short-term sources of variability. The approach highlights which behaviours are robust across conditions and which are sensitive to system constraints.

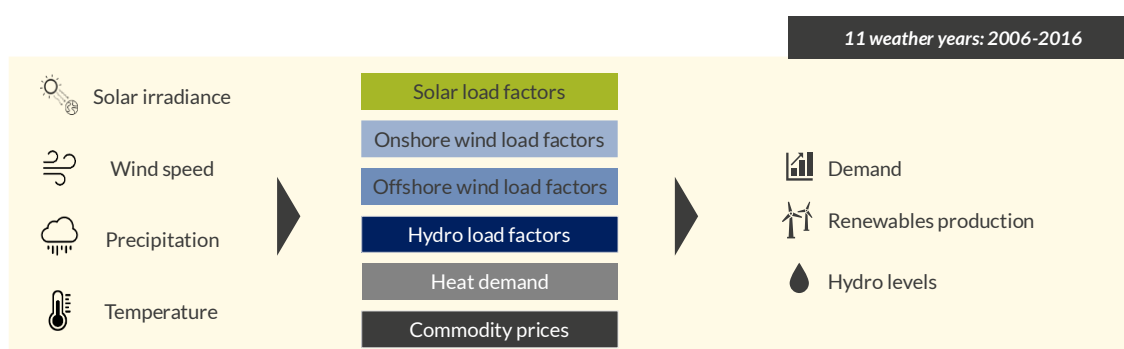
¹⁰ Installed capacity per unit of production aggregated by technology, RTE, as of 31/12/2025

Weather scenarios

Weather affects electricity systems through both renewable output (wind, solar, hydro) and temperature-driven demand. Aurora's Central scenario preserves the correlations between these weather-dependent variables by using 2013 as a reference meteorological year. This year was selected because, among the historical weather set (2006–2016), it produced baseload power price trajectories that were

closely aligned with the multi-year average, making it a neutral and representative basis for modelling. The profiles' means are then scaled to long-term averages. To capture inter-annual variability, the analysis also evaluates the *eleven historical weather years* individually, allowing observation of system behaviour under differing renewable generation and demand conditions.

Figure 5 - Eleven historical weathers years are evaluated in this analysis (2006-2016)



Source: Aurora Energy Research (2026)

Commodity price scenarios

Fuel and carbon prices influence marginal generation costs and therefore market prices. One sensitivity for this study is constructed around the central case. Commodity price assumptions are based on Aurora's High scenario, an upside case incorporating higher overall GDP growth.

The *High commodities* scenario considers gas and carbon prices approximately **+70% higher** than the central assumptions.

Nuclear availability scenarios

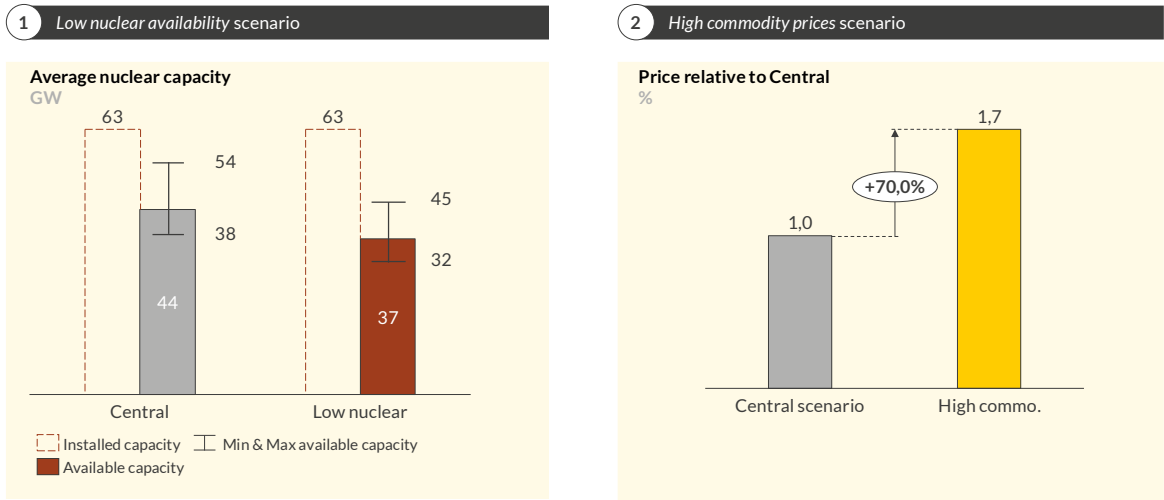
Nuclear availability is influenced by scheduled maintenance, refuelling cycles, regulatory inspections, and unforeseen technical issues, making it a meaningful

source of variability to reflect in system simulations.

- The *Central* scenario reflects typical maintenance and refuelling patterns, with availability calibrated to the average historical performance of the nuclear fleet.
- The *Reduced availability* scenario scales the same seasonal profile down to match the fleet availability observed in 2022 - the lowest in the past 25 years - due to longer maintenances to prepare life extensions of the plants, tail-end of covid disruptions and stress-corrosion cracking outages¹¹.

¹¹ OPEN Data EDF, Disponibilité du parc nucléaire d'EDF SA - Depuis 2002

Figure 6 - Two sensitivity scenarios are analysed in this report around nuclear availability and commodity prices



Source: Aurora Energy Research (2026)

3. Regionally coordinated market mechanisms ensure and optimise balance between supply and demand within physical and technological limits

This section outlines the general functioning of the European power system, describing the main market and how they interact. It then focuses on the key economic mechanisms that determine dispatch and price formation in the day-

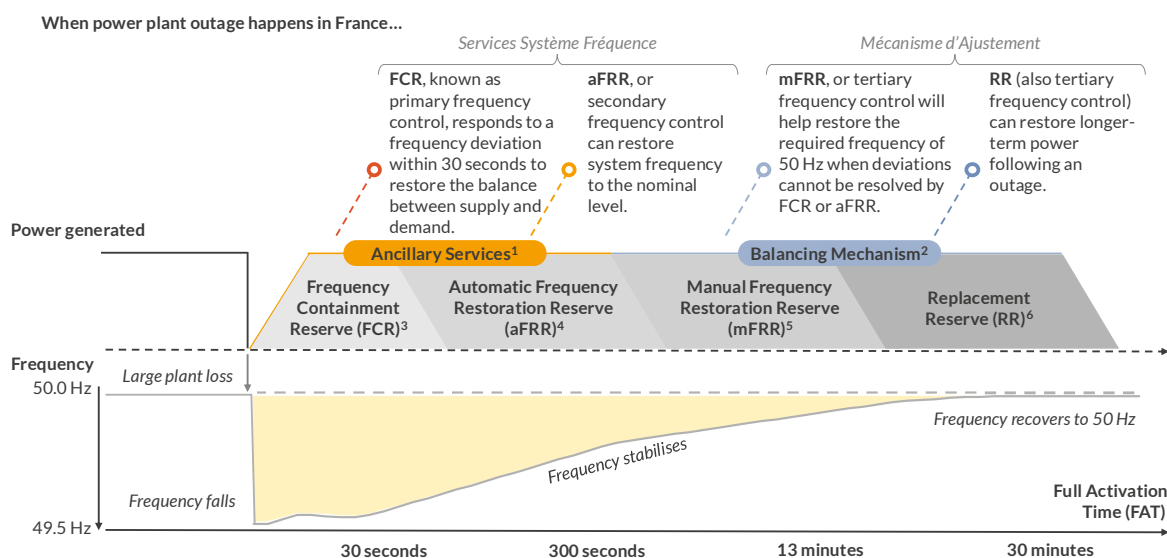
ahead market. Finally, it presents the expected and observed benefits of market integration at the European level. Readers already familiar with these concepts and wishing to focus directly on the study may proceed to Section 4.

3.1. Electricity’s instantaneous balance requirement and network physics constrain all operational decisions.

The European power system is an interconnected electrical network, and its operation is governed by physical laws. A first fundamental requirement is that electricity production and consumption must remain equal at every moment, despite forecast errors or unplanned outages. When this balance is not verified, system frequency deviates from its nominal

value. In the Continental Europe synchronous area¹², frequency must remain within 49.95–50.05 Hz under normal conditions. Deviations outside this narrow range reduce equipment performance and, if sustained or significant, can escalate into cascading failures and ultimately system collapse.

Figure 7 - System adequacy is maintained at all times by different response mechanisms



Sources: Aurora Energy Research (2026), ENTSO-E, RTE

¹² The region includes France, Germany, Spain, Italy, and most central European countries, but not Great Britain for instance.

Ensuring that this balance is continuously maintained is a core responsibility of Transmission System Operators (TSOs), such as RTE in France.

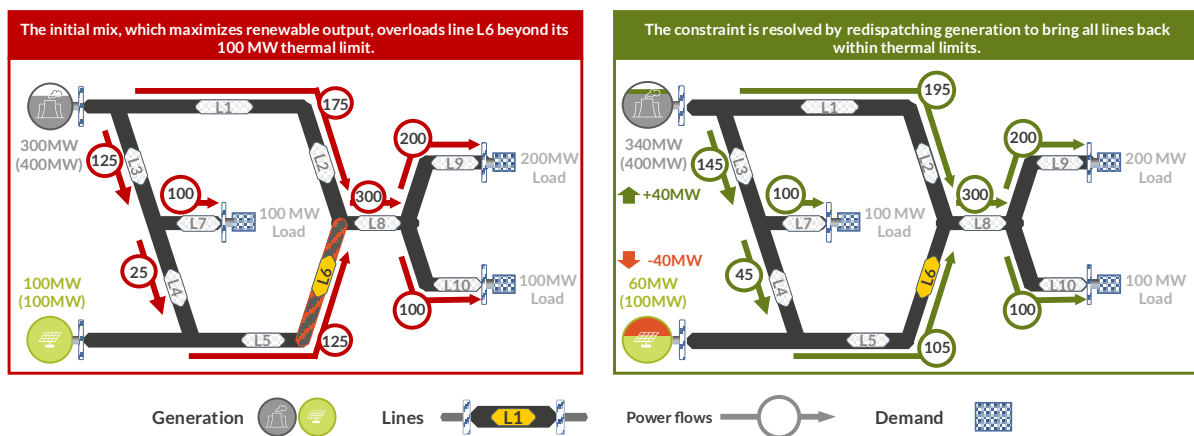
The complexity of ensuring this continuous balance is amplified by the non-storable nature of electrical energy at scale, especially on timescales above hours. To defer consumption, electricity is typically converted into another energy vector and later converted back into electricity. Pumped-storage hydropower stores energy mechanically by elevating water, whereas Li-ion batteries store it electrochemically. Similarly thermal generation can provide energy storage in the form of fuel stocks, which can be converted into electricity when needed. On the other side of the balance, demand-side response (DSR) introduces flexibility in consumption, adjusting load in response to system signals. These solutions help mitigate temporary mismatches between supply and demand, but they cannot substitute for the continuous coordination required to ensure system adequacy at all time scales.

Beyond this temporal dimension, spatial balancing is equally fundamental. Generation and consumption are rarely

located in the same areas, and electricity must travel through the transmission network to connect them. These flows do not follow contractual arrangements between participants. Once power is injected into the grid, its physical path is governed by Kirchhoff's laws: the flow automatically spreads across all nearby lines, according to the electrical characteristics of the network. In other words, the grid decides the path and operators can only influence flows indirectly through grid topology or redispatch actions (example below).

But every transmission line has technical limits, in particular thermal ratings which constrain the power allowed to flow through the asset. When flows approach these limits, the network becomes congested and system operation is therefore constrained not only by how much electricity is produced, but also by where it is produced. Cross-border interconnectors often represent the key bottlenecks of transmission networks, but internal network constraints can also be binding, restricting flows within countries or limiting the effective cross-border exchange capacities.

Figure 8 - Illustration of generation redispatch triggered by thermal transmission constraints



Frequency stability and power flows are fundamental to reliable system operation, and a reliable power system must also meet other technical requirements (inertia, voltage, reactive power requirements).

Together, these constraints define the safe operating space of the system within which there is still a wide range of possible ways for generation to meet demand. Which generators should operate, and when? At

any given moment, multiple combinations could supply the system. The “best” choice also depends on the objective: minimising generation costs, reducing greenhouse gases emissions, managing limited fuel resources, or supporting specific technologies.

Electricity markets provide coordination mechanisms which allow actors to reach a

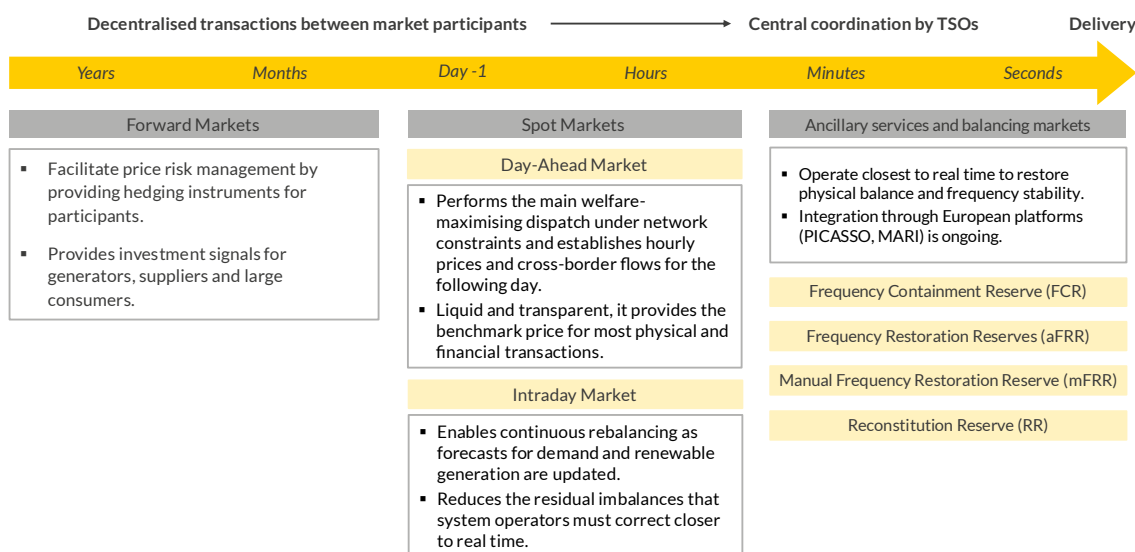
collective outcome. Markets do not override physics; they operate on top of physical constraints. They aim to translate constraints in flexible generation, network capacity and other critical resources into prices. These prices guide generators, consumers, and storage operators toward a dispatch that aims to be economically efficient and compatible with system security.

3.2. Sequential market timeframes progressively align expectations with real-time operation, ensuring both economic consistency and physical reliability

European electricity markets are structured along a chronological sequence of trading timeframes. Each timeframe helps refining the system’s expected operation towards a balanced and optimised dispatch. Together, these layers allow the system to adjust progressively while coordinating thousands of market participants. From long-term planning via forward markets to real-time

operation via ancillary services and balancing markets, each market has a distinct role. Efficient coordination among these timeframes ensures that prices across markets form a coherent signal. In a well-functioning integrated market design, each timeframe contributes to an iterative process that steers the system smoothly toward real-time balance:

Figure 9 - The system relies on markets from long-term hedging to real-time balancing



Source: Aurora Energy Research (2026)

In practice, however, several limitations reduce the efficiency of this sequence:

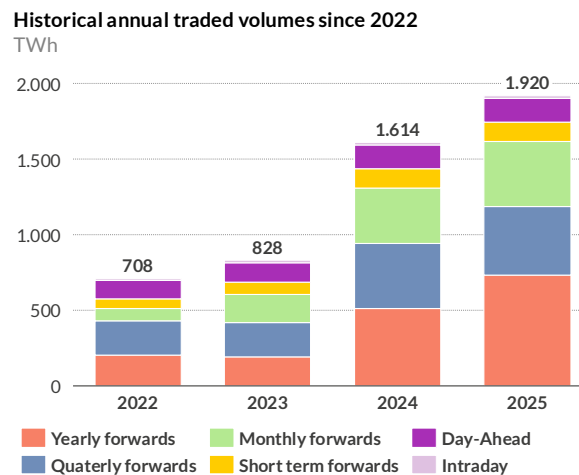
- Some constraints, such as internal grid congestions, are not captured in all markets of this sequence. These lead to redispatch actions outside the presented markets, resulting in higher system costs.
- Balancing markets are not yet fully harmonised. Procurement rules, product definitions, and activation procedures still differ across countries or are not necessarily accessible to cross-border capacities, reducing regional efficiency.
- Market performance depends on liquidity and transparency, which remain uneven across Europe despite ongoing EU efforts to improve them.

In reality, electricity traded on the day-ahead market represents only a portion of

total electricity volumes exchanged over a year. A significant share of energy is contracted in advance through forward, monthly, quarterly, or yearly products (Figure 10 – French annual traded volumes on wholesale markets by maturity). These transactions serve hedging and risk-management purposes and provide price visibility for market participants. However, forward prices generally converge toward spot-market prices as delivery approaches, and physical dispatch is ultimately determined in these short-term markets.

Because the day-ahead market establishes the reference dispatch and cross-border flows, it provides the most consistent representation of how generation technologies interact within the integrated European system. For this reason, the analysis in this study focuses primarily on day-ahead market outcomes.

Figure 10 – French annual traded volumes on wholesale markets by maturity¹³



Source: CRE, based on EEX, EPEX Spot, NordPool, Remit

¹³ Market transaction volumes can exceed annual physical production because the same unit of electricity may be traded multiple times before delivery, for example, across wholesale market stages or through portfolio adjustments. This does not imply that more energy is consumed than produced.

3.3. In the day-ahead market, two principles jointly determine generation dispatch and electricity prices: merit order ranking and marginal pricing

European power systems combine generation technologies with very different operating constraints and cost structures.

- **Variable renewable energy sources** provide low-marginal-cost, low-carbon electricity, but their output depends on meteorological conditions. Their availability is uncertain and does not necessarily align with demand patterns.
- **Baseload technologies** offer stable and dispatchable generation but are not optimised for rapid short-term flexibility, and their carbon emissions dependent on the fuel type.
- **Reservoir hydro and peaking plants** supply essential flexibility, enabling the system to respond to both rapid changes in demand as well as prolonged renewable deficits, often at high marginal costs.
- **Pumped storage, batteries and demand response** provide fast-acting flexibility but are limited by energy volumes and duration.

The day-ahead electricity market provides the primary mechanism to coordinate these diverse technologies on a quarter-hourly basis¹⁴. It determines the dispatch of power plants and sets their remuneration using two key economic principles: merit-order ranking and marginal pricing.

First, generation is selected according to a **merit order**, which ranks available generators by ascending short-run marginal cost (SRMC). This SRMC reflects the cost for a generator to produce one additional

megawatt-hour of electricity. It typically includes fuel costs, variable operation and maintenance costs, and, where relevant start-up or ramping costs.

Importantly, the SRMC does not include fixed costs such as capital expenditure or long-term maintenance. As a result, a generator is economically willing to produce whenever the market price is at least equal to its SRMC, since doing so allows it to cover the costs directly associated with production. Any price above the SRMC contributes to covering fixed costs and improving overall profitability, which explains why generators continue to operate even when market prices are relatively low.¹⁵

In Europe, additional cost components are incorporated into generators' bids. Fossil-fuel plants must account for the cost of CO₂ emissions under the EU Emissions Trading System, which is included in their marginal cost. This mechanism internalises part of the environmental cost of emissions and improves the relative competitiveness of low-carbon technologies.

For storage assets such as batteries and stock-based resources such as reservoir hydro, the concept of SRMC also includes an opportunity cost. Electricity injected into the system either reflects the cost of previously charging the asset or the use of a limited energy stock that could be sold at a later time. Operators therefore consider the expected future value of stored energy when submitting their bids, rather than only immediate operating costs.

As illustrated in Figure 11, variable renewable energy sources such as solar or

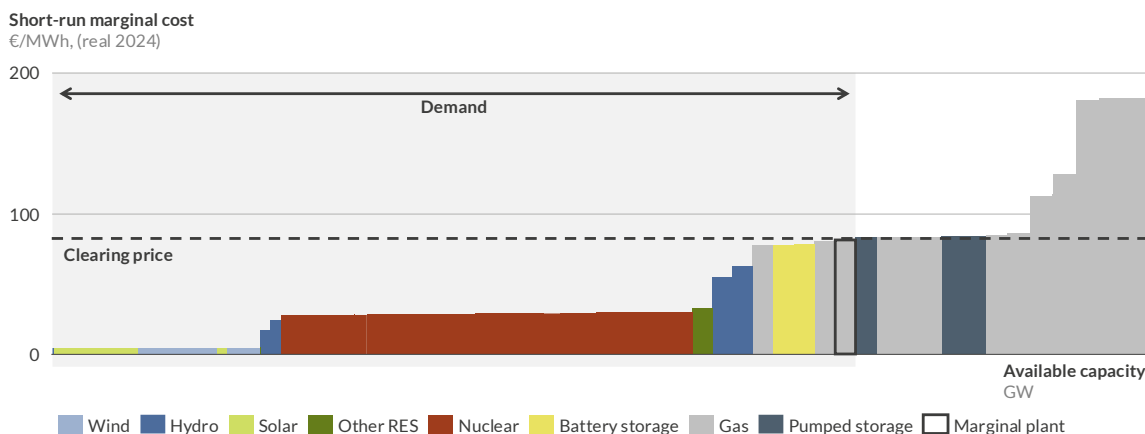
¹⁴ As of October 2025, European Day-Ahead markets switched from 60min to 15min Market Time Units.

¹⁵ In practice, bids do not always match the SRMC. For less flexible assets, they reflect intertemporal constraints (the dual value of the optimisation problem) and can be lower than marginal cost. For example, a generator may accept short-term losses in a given hour to avoid costly ramping or to maximise revenues in adjacent hours.

wind typically stand at the beginning of this merit order with marginal costs close to zero, while peaking fossil fuel plants are much more expensive and on the right side of this technology stack, with their SRMC

strongly impacted by fuel prices. Bids are accepted starting from the cheapest one until demand is met. This guarantees that the electricity mix selected corresponds to the lowest possible operating cost.

Figure 11 - Illustrative day-ahead market clearing during a high-demand hour in France: a gas unit sets the price at 90 €/MWh



Source: Aurora Energy Research (2026)

Second, the day-ahead market uses **marginal pricing**: all accepted generators are paid the same price per megawatt-hour of energy delivered. This price corresponds to the bid price of the last plant needed to meet demand. That is why the value of what is called the clearing price depends on the availability of the generators and the level of demand for each time unit. In the example above, we expect prices to be close to zero when renewable production is high and demand low and conversely when renewables and nuclear availability is limited, and demand is high to see prices above 100€/MWh. This mechanism provides transparency for all participants,

rewards offered capacity when the system is tight and at the same time allows high-capex plants with low SRMC technologies, such as nuclear and renewables, to recover part of their fixed costs over time since they are more frequently activated than other technologies.

While merit-order dispatch and marginal pricing explain generation dispatch and price formation within individual price zones, the physical interconnection of European electricity systems requires these mechanisms to be coordinated across borders to determine power flows and optimise regional system costs.

3.4. Market coupling economically coordinates resources and power flows across price zones.

No isolated system can have the optimal portfolio of resources at all times. Wind regimes differ between the North Sea and the Mediterranean, solar output is strong in

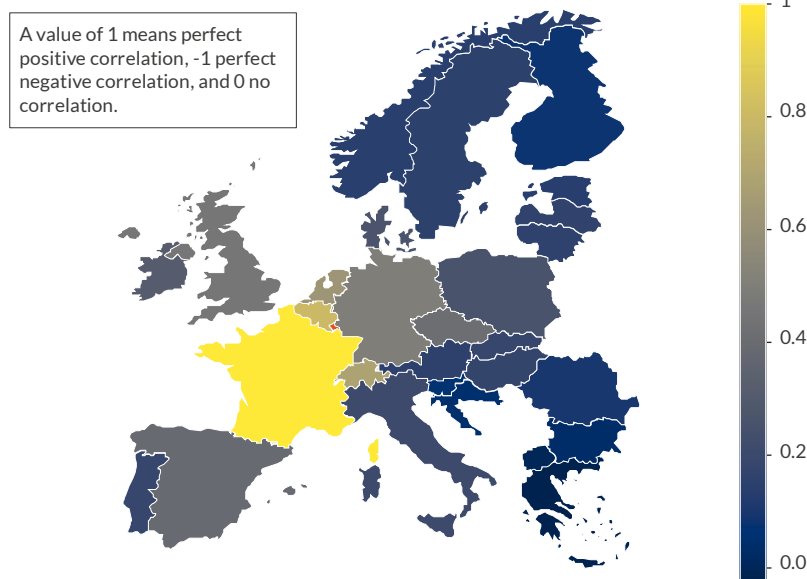
summer across most regions but provides limited contribution during winter demand peaks in continental Europe, Alpine and Nordic hydro provide storage capabilities

unavailable elsewhere, and thermal fleets vary in flexibility, fuel costs, and availability. Because meteorological patterns are only partially correlated (as illustrated for onshore wind in Figure 12) and natural

resources differ across Europe, cross-border coordination allows variability to be smoothed and flexibility to be pooled more efficiently than through domestic coordination alone.

Figure 12 - French wind production is most correlated with Belgium and Switzerland

French hourly onshore wind production correlation to other European countries (1980-2016)
Pearson correlation coefficient

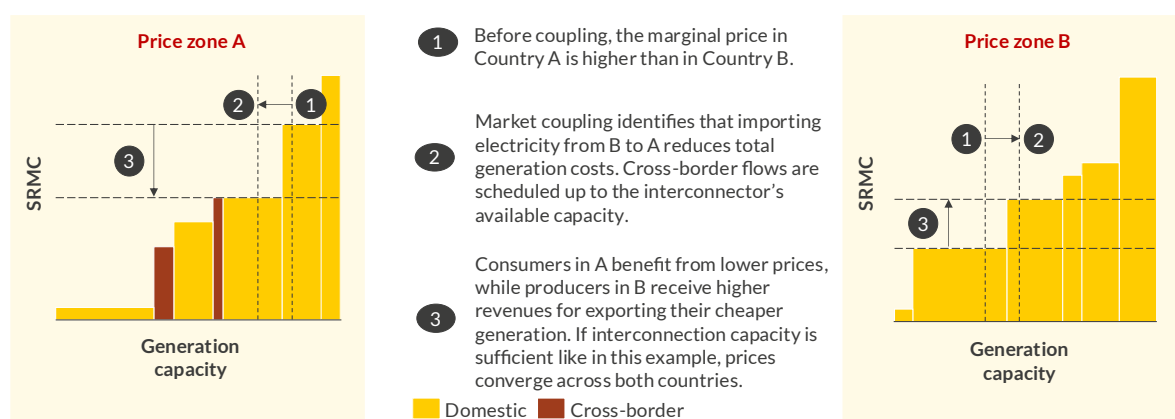


Source: Aurora Energy Research (2026)

Europe's heterogeneous generation mix creates operational complexity, but it becomes a system-wide asset when coordinated effectively. That is why the two previously mentioned principles, merit order and marginal pricing, are not applied separately in each price zone. Instead, dispatch optimisation is performed jointly across interconnected price zones. This integration is called **market coupling**. By coordinating this mechanism across price zones, the system can use the cheapest

resources wherever they are located, instead of having each country to rely on domestic generation alone, as long as exchanged are not constrained (Figure 13). When transmission capacity between two zones is sufficient, their prices converge toward a common marginal cost. This creates mutual welfare gains: consumers in high-price zones benefit from cheaper imports, while producers in low-price zones gain access to a larger market at a higher selling price.

Figure 13 - Market coupling economically coordinates generation power flows across price zones



Source: Aurora Energy Research (2026)

Because price differences vary over time, these benefits alternate in direction. A zone may be a net importer during high-demand winter periods and a net exporter during windy or sunny periods when its domestic production is high. The beneficiaries thus switch between consumers and producers depending on the flow direction, but the

gains are not necessarily evenly distributed. This potential asymmetry does not undermine the economic rationale for integration. From a regional welfare perspective, market coupling is always efficient. But it explains why concerns sometimes arise about the domestic impacts of cross-border trade.

3.5. Cross-border integration supports efficiency, reliability and decarbonisation, but its practical impact depends on coordinated implementation

Since cross-border market integration is a cornerstone of the European power system, its effects are closely monitored by institutions. Beyond the theoretical economic rationale, ACER and ENTSO-E reports confirm that integration delivers practical gains, not only improving resource use, but also strengthening system reliability, and supporting decarbonisation, although limitations in grid infrastructure and insufficient coordination still restrict its

full potential and integration cannot overcome all local challenges.

Efficiency and price convergence

Market coupling allows the least cost generation resources to serve demand across borders, reducing total system costs and increasing overall welfare¹⁶. In its assessment of the wholesale market design, ACER estimated that **cross border trade generated 34 billion euros in welfare benefits in 2021 at EU-level¹⁷**.

¹⁶ In this study, we assimilate generation cost minimisation and economic surplus maximisation. Although this equivalence does not strictly hold in the presence of non-convex bids, elastic demand, or deviations between bids and true marginal costs, it is generally regarded as a good approximation in European market-coupling analyses and is commonly adopted in the literature.

¹⁷ ACER, April 2022, Final assessment of the EU wholesale electricity market design.

Over the past four years, European market integration has deepened, contributing to greater price convergence, particularly within the Core¹⁸ region. Nonetheless, divergence remains frequent: price differences persist a substantial share of the time, and spreads of over 200 €/MWh were observed on several borders during periods of tight supply in 2024 (notably Austria–Hungary and multiple South Eastern Europe borders)¹⁹.

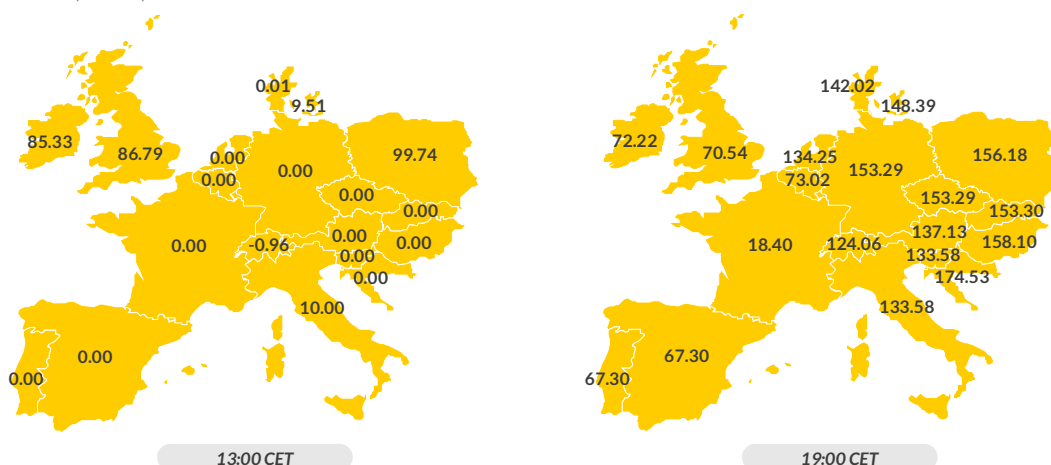
While cross border integration is already economically beneficial, ACER finds that a better use of existing grids would unlock

even larger benefits. Under EU law, at least 70% of physical capacity on critical network elements must be made available for cross zonal trade. Yet, according to ACER’s findings, only 40% of borders met this requirement on average in 2024. Full implementation of the 70% rule would have had substantial benefits. ACER estimates that in 2024 alone:

- 147 severe price spikes in Southeast Europe could have been avoided
- Average day-ahead price would have been 2 €/MWh lower, in particular 9 €/MWh during peak hour

Figure 14 - Day-ahead price for two hours on September 14th, illustrating price convergence

Hourly day-ahead market price on September 14th, 2025
€/MWh (nominal)



Sources: ENTSO-E, RTE

Security of supply: shared resources reduce adequacy risks

Cross-border integration also strengthens security of supply by allowing countries to rely on a larger pool of generation and flexibility resources. In adequacy assessments, security of supply is essentially evaluated by comparing the generation capacity available under

stressed conditions with expected peak demand. A larger and more diversified resource base increases the probability that sufficient capacity will be available when it is most needed. ENTSO-E’s annual ERAA assessments consistently show that adequacy outcomes improve at the regional level compared to purely national

¹⁸ The Core Capacity Calculation Region consists of bidding zone borders between the following countries’ bidding zones: Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxemburg, the Netherlands, Poland, Romania, Slovakia and Slovenia.

¹⁹ ACER. Transmission capacities for cross-zonal trade of electricity and congestion management in the EU – 2025 Monitoring Report. Sept. 2025.

assessments, confirming the risk-mitigation effect of resource sharing across borders.

Recent system stress events have demonstrated this benefit. During the winter of 2018–2019, Belgium faced a significant adequacy challenge following large, unplanned nuclear power plant outages. To compensate for the resulting generation shortfall, the Belgian TSO maximised import capacity, reaching an average hourly import level of around 2.5GW, compared with typical flows of approximately 0.85GW the previous year. This type of support is only possible in an interconnected market, where cross-zonal transmission ensures that available resources can flow to where they are most needed.

Nevertheless, the effectiveness of cross border support may be limited when scarcity is correlated across regions. Europe wide cold spells or extended *dunkelflaute* events reduce the diversification value of interconnection, as constrained supply and high demand occur simultaneously across many bidding zones. In such situations, available cross border capacity still helps smooth localised imbalances but cannot fully offset regional scarcity²⁰.

Renewable integration

Regional market integration improves renewable integration by helping the system to accommodate higher shares of variable generation with less wasted electricity and lower system costs. This occurs through two complementary mechanisms:

First, it **limits economic curtailment**. When a country produces more wind or solar power than domestic demand can absorb, interconnectors allow this surplus to be exported rather than curtailed. By expanding the effective market size, cross-border trade creates additional demand for low-marginal-cost renewable electricity. Importing countries benefit as well, since renewable imports can displace more expensive and often more carbon-intensive generation.

Second, it **reduces congestion-driven curtailment**. When internal network constraints prevent renewable output from reaching consumers, cross-border capacity can provide alternative outlets for electricity flows, relieving bottlenecks, reducing the need to curtail generation, and limiting costly redispatch actions²¹.

Cross-border integration delivers clear benefits in terms of efficiency, adequacy, and decarbonisation. Its practical impact can be further strengthened through enhanced physical infrastructure and improved operational coordination across regions. At the same time, certain situations such as correlated weather events affecting multiple regions simultaneously limit the diversification benefits of integration.

However, this does not diminish the value of integration; rather, it underscores that interconnection is a necessary but not sufficient condition for system resilience. Domestic flexibility, effective cross-border coordination, and diversified generation portfolios must operate jointly to ensure robust outcomes. The following sections illustrate these interactions through detailed modelling results.

²⁰ ENTSO E. (2025). European Resource Adequacy Assessment (ERAA) – 2025 Edition: Executive Report. European Network of Transmission System Operators for Electricity.

²¹ ACER. Transmission capacities for cross-zonal trade of electricity and congestion management in the EU – 2025 Monitoring Report. September 2025.

4. Price spreads and cross-border exchanges reflect regional synergies and highlight the french power mix contribution to Europe’s affordability and decarbonisation objectives

Merit-order, marginal pricing, and market coupling define the theoretical architecture of the European electricity market. Their impact is continuously monitored by European energy institutions, which quantify their benefits and analyse their limitations.

However, understanding the concrete behaviour they induce and how these mechanisms translate into observable system benefits can be challenging. Real-world power markets are affected by multiple sources of uncertainty: meteorological variability, unplanned outages, volatile fuel prices, and broader geopolitical events. These factors interact

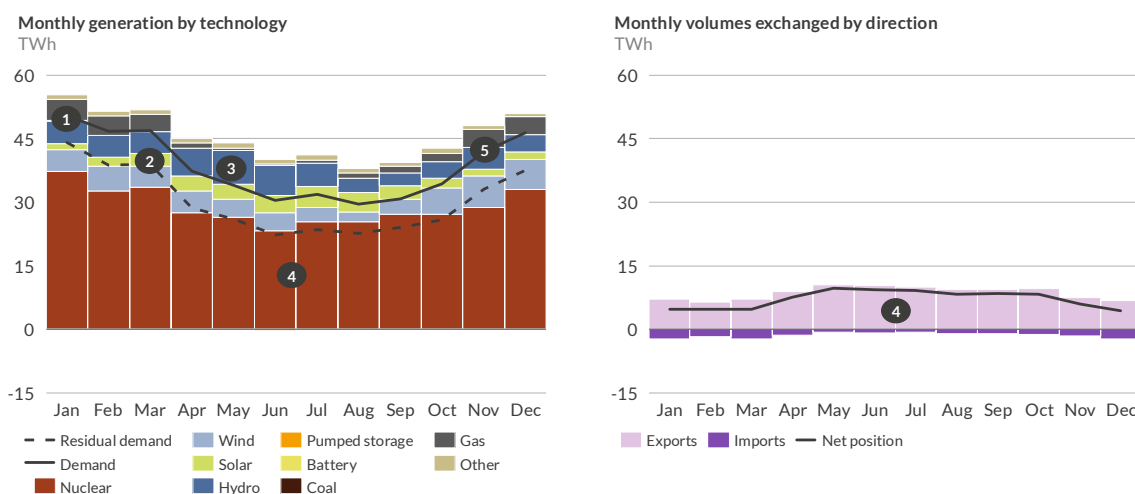
with one another creating dynamics that are not always intuitive.

The following two sections use a modelling approach in which key assumptions are stable and explicitly defined, allowing structural dynamics to be clearly described. By simulating the power system under controlled conditions, the contribution of specific drivers can be isolated and their individual impacts quantified. This section provides a reference picture of how France participates in the integrated European market, how it complements neighbouring systems, and what it gains from these interactions, while illustrating typical daily and seasonal behaviours.

4.1. Seasonal and daily patterns of renewables and demand define the system’s flexibility needs from storage and dispatchable resources

4.1.1. Thermosensitivity of demand and annual hydro cycles shape nuclear maintenance schedule and conventional capacity dispatch

Figure 15 - Seasonality of demand and annual hydro cycles shape nuclear maintenance schedule and drive conventional capacity dispatch



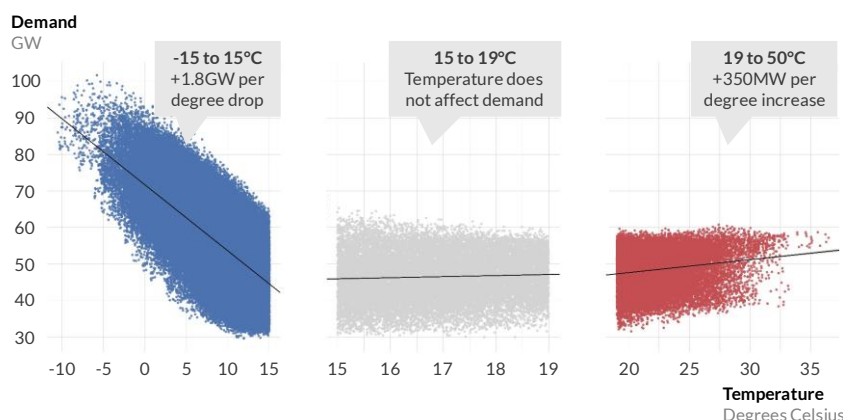
Source: Aurora Energy Research (2026)

1 Seasonal temperature variations determine the demand profile

Electricity demand shows strong seasonal fluctuations driven by temperature which affects heating and cooling needs. France is one of the most thermosensitive power systems in Europe: winter cold spells sharply increase demand due to widespread

electric heating: A 1°C drop in temperature leads on average to an additional 1.8GW in power demand²². In contrast, summer demand remains comparatively low, although the growing use of air conditioning in warmer Southern countries is increasingly pushing summer demand upward.

Figure 16 - France's energy consumption is highly sensitive to lower temperatures



Sources: Aurora Energy Research, renewables.ninja, RTE

2 Seasonal renewable availability determines the base of the supply profile

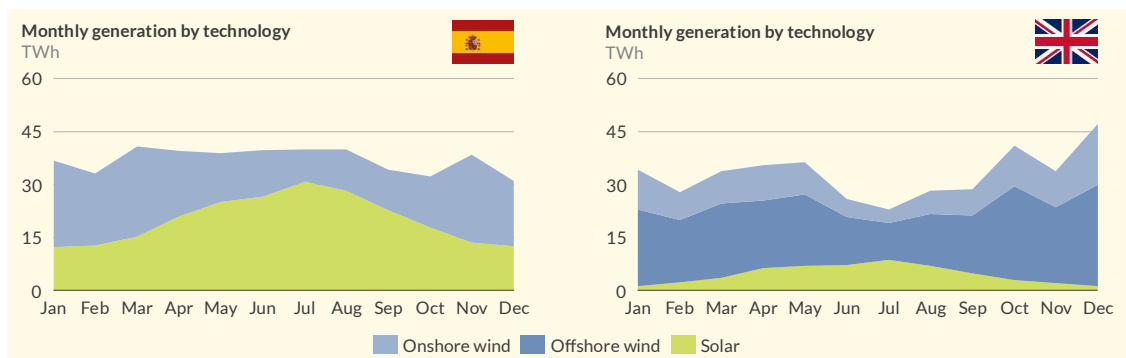
Each generation technology has a distinct seasonal pattern. Solar PV output peaks in summer when irradiance is highest, while winter production is significantly lower. Wind generation follows an opposite trend: wind speeds are generally stronger in winter, making wind a structurally winter-oriented resource. These resources are also unevenly distributed across Europe, shaping national capacity deployment strategies. Spain's renewable mix is dominated by solar, whereas Great Britain relies heavily on wind, particularly offshore

wind, supported by favourable coastal conditions. This is illustrated in Figure 17.

In the Central 2026 scenario, variable renewable energy sources cover a large share of total annual demand, 59% in Spain and 45% in Great Britain. France, with 33GW of solar and 29GW of wind, covers 21% of its demand with variable renewable energy sources. Even at lower penetration levels, these technologies strongly influence market dynamics because they sit at the bottom of the merit order: when available, they displace higher-marginal-cost technologies and compress the residual demand.

²² In countries where heating is less electrified, heating demand is met more by other energy sources, often fossil fuels.

Figure 17 - Different wind and solar capacity mixes across European countries create varying seasonal profiles of variable renewable availability



Source: Aurora Energy Research (2026)

Residual demand: the key link between consumption and dispatchable generation

Variable renewable generation does not always coincide with seasonal and daily demand patterns. Residual demand, defined here as demand minus wind and solar generation, determines how much dispatchable capacity is needed to maintain energy supply-demand balance. When renewables are plentiful, residual demand is low and few additional capacities are needed, sometimes none. When renewable output is scarce during periods of high consumption, residual demand rises and the system relies more heavily on nuclear, hydro, other thermal generation, and cross-border imports. This concept provides the bridge between demand variability and the role of dispatchable technologies.

3 Hydro reservoirs allow inter-seasonal balancing

France's hydro capacities, particularly large reservoir and pumped-storage units, provide a crucial source of seasonal flexibility. Reservoir levels are typically replenished during wetter and lower-demand periods (spring and autumn) and drawn down during winter peaks or prolonged renewable deficits. In this way, this technology acts as inter-seasonal storage, helping align consumption patterns with the variability of wind and solar generation. However, its ability to smooth seasonal imbalances remains bound by annual water inflows and reservoir storage limits.

Pumped storage units provide higher operational flexibility since they can restore their energy reserves by consuming electricity. However, an important share of these units have more limited storage capacities than large reservoirs, making them better suited to tackling multi-day or multi-week variability.

4 The French nuclear fleet provides both a stable backbone and operational flexibility

Nuclear generation forms the core of France's supply mix, covering 58% to 69% of monthly domestic generation in the modelled year. Its low marginal cost ensures high utilisation when available, significantly reducing the need for fossil-fuel generation together with renewables.

The nuclear seasonal output profile aligns closely with monthly consumption patterns.

Refuelling and maintenance are generally scheduled in spring and summer, when demand is low, enabling higher availability during winter peaks. This provides multi-week to multi-month flexibility, offering a form of inter-seasonal balancing.

The size of the French nuclear fleet also supports France's structural net export position, especially in summer when domestic demand is low and renewable output remains high. The low carbon surplus can then be further directed toward regional exports.

5 Gas-fired plants remain essential for seasonal adequacy

Fossil-fired technologies, mostly gas in the case of France, remain essential for seasonal adequacy during winter months. In the simulated year, gas plants account for up to 10.1% of monthly demand, providing the marginal capacity required to maintain system balance and avoid supply shortages during periods of high residual demand. Conversely, they operate at much lower load factors during milder months, covering as little as 1.3% of monthly demand in May²³.

Their operational flexibility, thanks to relatively fast start-up times and ramping rates, also makes them well suited for balancing variable wind and solar generation. In a system with growing shares of renewables, gas-fired generation therefore increasingly serves as a back-up and peak resource rather than a baseload technology.

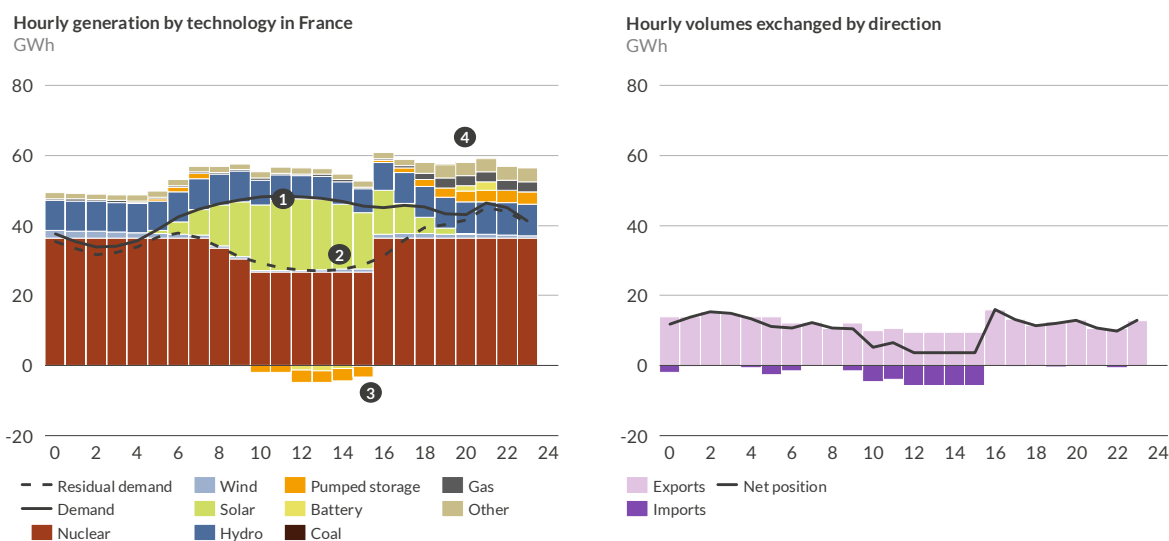
²³ This generation share does not consider the contribution of these technologies to ancillary services and balancing markets.

4.1.2. Daily dispatch patterns follow predictable daily cycles driven by solar generation and demand ramps

Daily electricity system behaviour is largely driven by recurring patterns in both consumption and renewable output. Solar production rises and falls predictably with daylight hours, while demand follows a

characteristic morning-evening profile. The interaction of these two cycles determines the magnitude and timing of residual demand, which in turn drives dispatch and cross-border flows²⁴.

Figure 18 - Flexible generation and interconnectors balance solar midday output and demand ramps in the morning and evening



Source: Aurora Energy Research (2026)

1 Consumer behaviour shapes daily demand profiles.

Electricity demand increases during the morning start-up period as households begin their daily activities and businesses resume operations. This first peak is driven by heating or cooling needs, lighting, and the start-up of equipment. After stabilising around midday, demand rises again in the early evening when households return home. This second peak is often stronger, reflecting increased residential use for cooking, lighting, entertainment, electric vehicle charging, and temperature control. These daily patterns are largely shaped by behavioural routines and are more

pronounced in winter due to higher heating needs.

2 Solar generation depresses mid-day residual demand.

Solar PV production increases sharply late in the morning, reaches its peak around midday, and declines in the afternoon. This displaces mid-merit generation, typically gas and sometimes coal in neighbouring countries, and lowers day-ahead prices during central hours. In highly solar systems, this creates the familiar “duck curve,” with steep upward ramps once solar output declines.

²⁴ A typical summer day (July 1st) is used to illustrate these dynamics. In a typical winter day, one would expect higher demand, lower PV generation, and potentially greater reliance on imports. However, the underlying operational relationships between technologies would remain broadly similar.

By contrast, other renewable sources such as wind and run-of-river hydro exhibit less pronounced daily patterns. Wind generation depends primarily on meteorological conditions rather than time of day, while run-of-river hydro follows seasonal rivers inflows, resulting in smoother or less structurally predictable daily behaviour compared with solar PV.

3 Flexible technologies and cross-border exchanges accommodate renewable variability throughout the day.

The French generation mix is primarily based on nuclear and renewable energy. When their combined output exceeds domestic demand:

- Nuclear itself can provide within-day modulation, delivering several gigawatts of upward or downward adjustment while maintaining a strong baseload contribution.
- Batteries and pumped storage can absorb part of the midday solar surplus by charging during low-price hours. However, under the 2026 assumptions considered here, the relatively limited installed battery capacity constrains the overall impact

of this technology. Demand-side flexibility such as EV charging, heat pumps, data centres, and electrolyzers is already reflected in the demand profile of the model.

- Unlike seasonal patterns, when residual demand declines around midday in this illustrative day, France's net export position narrows. This reflects increased imports from neighbouring countries with higher solar penetration, which can provide cheaper electricity than the French technology stack during these hours.

4 High merit order technologies ramp up in the evening.

As solar output decreases and demand increases in the evening, non-baseload technologies are activated. Short-duration storage discharges the energy accumulated earlier during low-price periods, for example during the midday solar peak. Thermal plants may ramp up to meet the residual demand peak or to respond to the steepest variations when other flexible sources are insufficient. During these hours, prices are typically higher and the marginal technologies more carbon intensive than during the rest of the day.

4.2. These patterns determine which technologies are dispatched and which become marginal, shaping CO₂ intensity and prices

The higher the residual demand, the more expensive, and typically more carbon-intensive, plants must be dispatched. This relationship is clearly reflected in the seasonal and hourly distribution of average day-ahead prices and carbon intensity in Figure 19.

During high-residual-demand hours, most often the morning and evening peaks, especially in winter when heating demand rises, average prices exceed 100 €/MWh and reach up to 124 €/MWh around 18:00 in November. At these times, average carbon intensity reaches 26gCO₂/kWh²⁵, only slightly below the annual maximum

²⁵ Throughout this report, carbon emissions and carbon intensity refer exclusively to direct CO₂ emissions from fuel combustion. They do not account for other greenhouse gas emissions, nor for full life-cycle assessment emissions. As a result, solar, wind, hydro, and nuclear generation for instance are treated equivalently in this framework, with their direct emissions considered zero. The value provided by RTE for 2025 accounts for all greenhouse gases and is therefore necessarily higher.

observed at 17:00 in February. These periods correspond to the activation of marginal thermal units needed to meet high residual load.

Conversely, during low-residual-demand hours, nuclear and sometimes renewable generation alone can be sufficient to meet demand from an energy balance perspective. This drives carbon intensity close to zero and results in very low prices. The minimum price averages 1.83 €/MWh for June days between 12:00 and 13:00. These periods correspond to the dominance of technologies that are both low-carbon and low marginal-cost in the retained merit order.

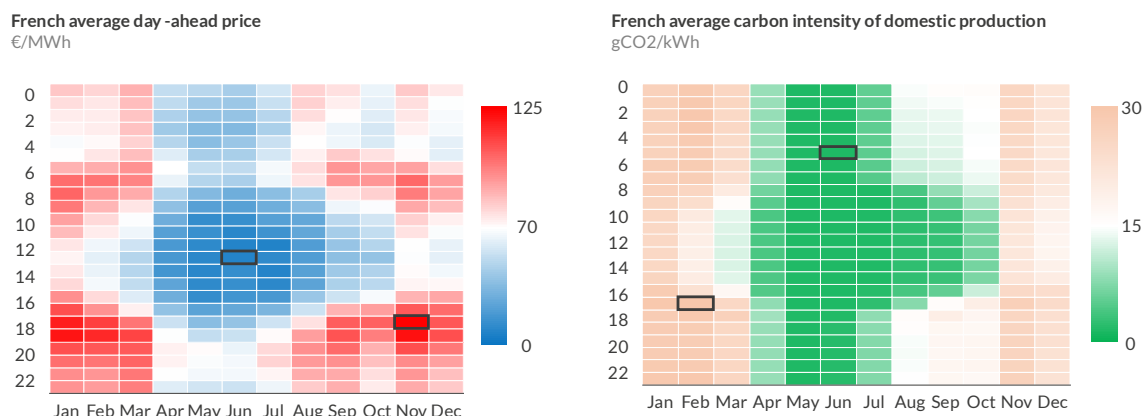
Over the entire modelled year, the combined effects of these dynamics result in an average wholesale price of 66 €/MWh and a carbon intensity of 14.2gCO₂/kWh. For comparison, in 2024 the historical average day-ahead price in France was 58€/MWh, while the direct greenhouse gas

intensity of electricity generation was 21.7gCO₂eq/kWh.

While in France these two characteristics are largely correlated, this relationship is not universal. Electricity prices are determined by the marginal technology in the dispatch stack, whereas carbon intensity reflects the emissions associated with the entire dispatch mix at a given moment. In systems that rely on relatively inexpensive fossil baseload capacity, even hours with low residual demand may remain carbon intensive. This is why carbon pricing is implemented in practice: by internalising emissions into production costs, it helps align economic signals with carbon performance.

It is also important to note that this calculation does not account for the additional costs and emissions associated with real-time system balancing, where flexible thermal generation units are typically dispatched more intensively.

Figure 19 - Residual demand patterns determine which technologies become marginal, shaping price formation and CO2 intensity across the year



Source: Aurora Energy Research (2026)

These dynamics also appear in neighbouring countries. In all systems, dispatch is driven by the need to cover residual demand. The intensity of these patterns and the technologies involved differ by country, reflecting structural differences in demand profiles and generation mixes. These divergences are precisely why cross-border exchanges are valuable: when coordinated, they allow national systems to complement one another and improve overall regional economic efficiency.

4.3. Structural differences in generation mixes create persistent price spreads across zones reflected in cross-border exchanges

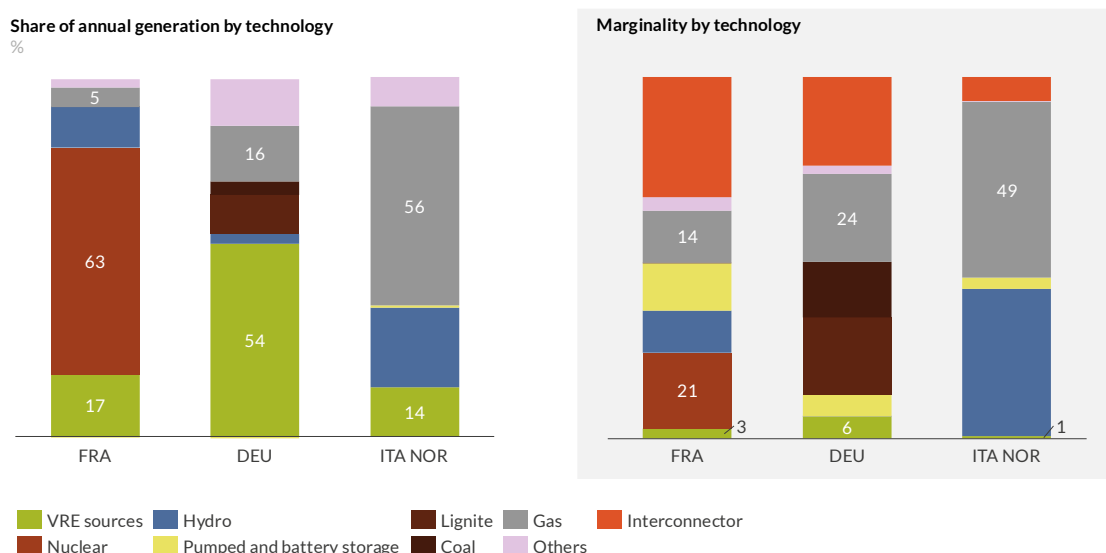
National generation portfolios reflect policy decisions, historical investment cycles, and domestic resource constraints. These factors explain why geographically close countries may display structurally different generation mixes, as illustrated in Figure 20. French generation relies predominantly on nuclear power, complemented by hydro and renewables. Germany, by contrast, sources more than half of its electricity from wind and solar, supported by conventional thermal units. Northern Italy relies heavily on gas-fired generation, with hydro and VRE playing a secondary role.

However, day-ahead prices and cross-border flows are determined not by the overall generation mix, but by the production cost of the marginal plant. When focusing on the marginality of each technology, defined as the percentage of

hours during which a given technology sets the market price, the marginal mix differs completely from the production mix.

A technology may account for a large share of total generation while playing only a limited role in price formation. This is the case for French nuclear power, which sets the price in only around 21% of hours despite dominating total output. This effect is inherent to marginal pricing and becomes more pronounced the lower a technology sits in the merit order. In Germany, VRE set the price in only 6% of hours, despite representing 54% of total generation over the modelled year. Conversely, mid-merit technologies such as gas and flexible resources such as pumped hydro set prices in a disproportionately high share of hours relative to their annual generation.

Figure 20 - Zonal prices cannot be inferred from generation mixes alone; what ultimately matters is which technologies are marginal



Source: Aurora Energy Research (2026)

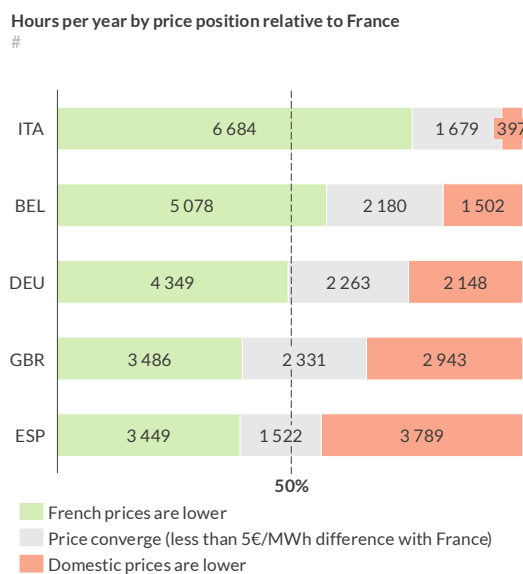
Furthermore, Figure 20 shows that cross-border capacity frequently determines a zone's price: the marginal unit is not necessarily located domestically. When interconnectors are not congested, the price in each bidding zone is determined by the most expensive plant dispatched anywhere in the coupled region. If France exports electricity but the marginal cost of increasing domestic production exceeds the marginal cost of the price-setting unit elsewhere in the coupled area, the foreign marginal unit will set the price across all fully coupled zones.

This mechanism is particularly visible in France, where close to one-third of hourly prices are set by foreign units. This reflects France's strong interconnection with

neighbouring systems, which increases its exposure to regional price-setting dynamics. Considering the five neighbouring zones analysed, price convergence within ± 5 €/MWh with at least one neighbouring zone is observed in close to 70% of hours.

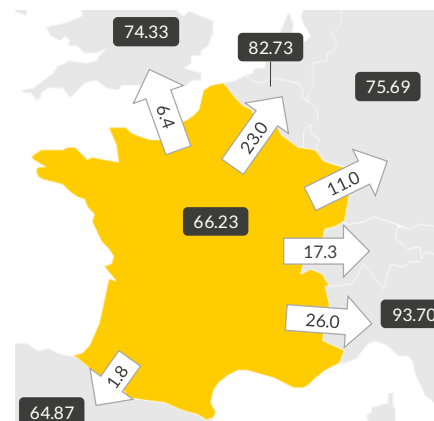
However, these convergence episodes do not necessarily occur simultaneously across all borders. France may converge with Germany while maintaining a price spread with Spain, and bilateral price convergence occurs only between 17% and 27% of the time with each individual neighbouring zone. These persistent price gaps reflect the combined effect of limited interconnection capacity and structural differences in marginal costs across generation mixes.

Figure 21 - Cross-border flows typically follow marginal-cost differences between bidding zones, and price convergence signals effective market coupling



Source: Aurora Energy Research (2026)

Cross-border flows resulting from market integration
Net position (arrows) - TWh, average price (boxes) - €/MWh



And these spreads guide cross-border flows: when interconnection capacity is available, electricity moves from lower-price to higher-price areas. In practice, France often records lower marginal prices than its neighbours (Figure 21), resulting in a high number of hours during which it is expected to export. This dynamic is particularly visible in exchanges with Northern Italy. In the simulated year, Italian

prices were higher than French prices in more than 6,000 hours, with an average spread of 27 €/MWh in France's favour. This sustained price difference translates into net annual exports of 26 TWh from France to Northern Italy.

More broadly, there is a positive relationship between economic competitiveness and net trade position. In France's case, exports are supported by

substantial volumes of low-marginal-cost generation, which at times exceed domestic demand and can therefore be directed toward neighbouring markets.

Still, the annual net position should not mask that economic efficiency is determined hour by hour, with price

spreads alternating in direction over time. Throughout the year, France is cheaper than all its neighbours in only 32% of hours. During the remaining hours, at least one neighbouring country has a marginal cost at least 5 €/MWh lower than France's, underlining the complementarities between national generation mixes.

4.4. France and its nuclear fleet play a central role in lowering regional electricity prices and reducing carbon intensity

4.4.1. As one of Europe's most interconnected country, France acts as a hub for resource sharing and contributes to reduce regional price levels

France is one of the most interconnected power systems in Europe. Total cross-border transfer capacity has roughly doubled since 2010 to reach 23GW of export capacity and 18GW of import capacity. The country sits at the crossroads of the Iberian Peninsula, the British Isles, the Benelux region, Central Europe and Italy. These neighbouring systems rely on different generation technologies and experience distinct weather patterns, leading to diversified renewable generation profiles across the region.

Such diversity creates opportunities for complementarity between national power systems. A high level of interconnection facilitates the exchange and transit of low-carbon, low-cost electricity across the region, for example from Spanish solar generation or British offshore wind during

periods of high renewable output. From a geographical perspective, France is well positioned to enable synergies in Western Europe.

Beyond simply facilitating complementarities between neighbouring systems, the French power system contributes directly to lower regional wholesale prices, as evidenced by its structural position as a net exporter. In the Central scenario, annual exports amount to 102.7TWh, compared with 17.2TWh of imports. This result is in line with the export record observed by RTE in 2025, when France's net export position reached 92.3TWh. By supplying neighbouring markets with competitive, low-carbon electricity, the French mix supports European decarbonisation and electricity affordability objectives.

4.4.2. The French nuclear fleet is central to this contribution: ensuring a high level of availability from the fleet helps maintain low electricity prices and carbon emissions

When nuclear output declines, the French generation stack loses a large volume of low-marginal-cost capacity at the bottom of the merit order. Given the typically high load factor of nuclear plants, this translates into considerable loss of electricity

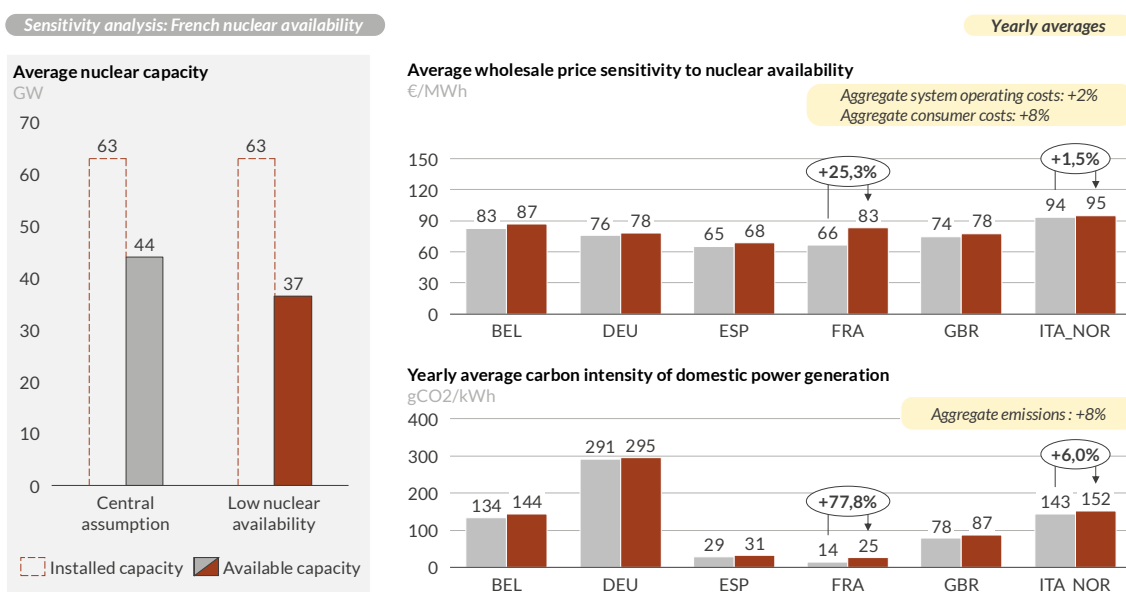
production compared with most other technologies in France. As a result, the system relies more frequently on higher-cost and fossil-based units.

France is naturally the most exposed to such a situation. A drop in nuclear availability

similar to the one observed in 2022, corresponding under the chosen assumptions to an average available capacity of 37GW over the year out of 63GW installed (instead of 44GW in the Central case), increases average power prices in France by approximately 25%. This underlines the sensitivity of French electricity prices to the operational level of

the nuclear fleet. Maintaining sufficient available capacity is therefore essential to keeping wholesale prices low and, by extension, limiting consumer bills. The impact on neighbouring countries is also significant, with prices rising by 1 to 4 €/MWh across all considered zones. Overall, total production costs rise by 2%.

Figure 22 - The French nuclear fleet is central to the country’s contribution to regional decarbonisation and electricity affordability



Source: Aurora Energy Research (2026)

The implications for carbon intensity are immediate. Reduced nuclear generation is compensated by fossil generation. Domestically, France activates its thermal fleet more frequently, leading to an increase in the carbon intensity of its production by around 11gCO₂/kWh, a 78% increase compared to the 14gCO₂/kWh observed under the Central scenario. At the same time, lower volumes of low-carbon electricity available for export lead to greater activation of fossil units in

neighbouring systems. As a result, their carbon intensity increases as well and total emissions increase by 19 MtCO₂, an 8% rise.

These results highlight the importance of the French nuclear fleet, not only for domestic affordability and decarbonisation, but also for the region as a whole. While the entire French generation mix contributes to achieving European energy objectives, maintaining high nuclear output is a key element of France’s contribution.

4.4.3. In addition, French nuclear capacity provides a partial buffer against volatile fossil fuel costs

When gas or carbon prices rise, they increase the short-run marginal cost of fossil-fired plants, which in turn raises the price at which these units offer their generation. Storage and reservoir technologies, for their part, typically bid based on opportunity cost. Because they have a limited stock of stored energy, they must allocate it carefully over time. To maximise their value, they usually bid slightly below conventional thermal units to displace them in the merit order, but close enough to capture a high market price. As a result, their bidding behaviour is also indirectly influenced by gas and carbon price movements. So, whenever fossil or storage plants are marginal, day-ahead electricity prices rise under a high-commodity-price scenario.

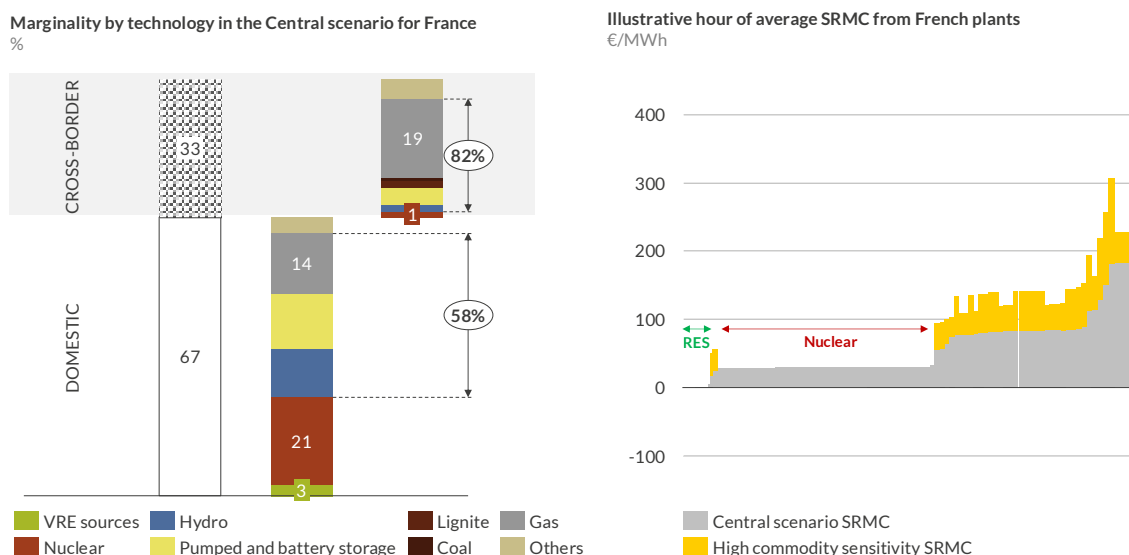
Together, these technologies in France account for around 58% of the domestic marginal mix and up to 82% of the non-domestic marginal mix. Overall, they set the

price in approximately 66% of hours over the year in the Central scenario. Since gas is the dominant fuel among price-setting fossil technologies, this explains the origin of the commonly cited, though somewhat misleading, notion that electricity prices are “indexed” to gas prices.

By contrast, nuclear and renewable technologies have marginal costs that are insensitive to gas and carbon price fluctuations. As shown in Figure 23, the segments of the merit order corresponding to these technologies remain unchanged when commodity prices rise. When they are marginal, electricity prices are therefore not directly affected by fossil fuel costs increases. In this way, they help stabilise price levels during commodity shocks.

However, this buffering effect is limited in practice because it only applies when nuclear or renewables set the price, roughly 25% of hours in France in this study.

Figure 23 - French nuclear capacity also serves as a partial buffer against volatile fossil marginal cost



Source: Aurora Energy Research (2026)

Nevertheless, their influence is still reflected in the relative price increases observed across the region under the high

commodity price scenario. While all analysed countries experience a sharp price increase, with average prices reaching close

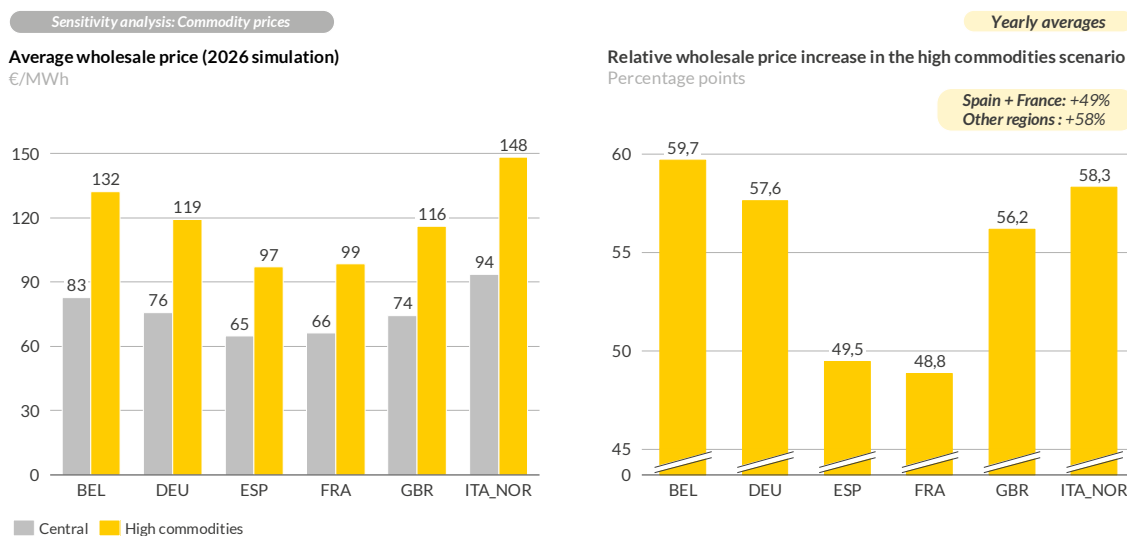
to or above 100 €/MWh, differences in marginal mixes lead to noticeable divergences between power systems (Figure 24).

Spain and France see average price increases of around 49%, approximately 9 percentage points lower than in other price zones. This lower sensitivity is driven by the

20–30% share of fossil-price-insensitive technologies setting the marginal price.

Overall, power systems whose marginal mix includes a significant share of low-carbon technologies demonstrate greater resilience to commodity price shocks, and the nuclear fleet is the main direct contributor in France²⁶.

Figure 24 - Marginal mixes with lower exposure to gas and CO₂ prices contain price increases when these commodity prices surge



Source: Aurora Energy Research

²⁶ In Spain, these price-insensitive technology are largely solar and wind.

5. Stress events reveal how meteorological extremes challenge system adequacy and demonstrate the value of dispatchable resources and interconnections

The previous sections described average system patterns, providing an understanding of typical dispatch dynamics and the resulting average electricity prices and carbon dioxide emissions. These patterns provide a useful reference point, but conditions at a given hour, day or week may deviate significantly from these average values. Even within a modelling framework, already less volatile than real-world operation, the system showcases high variability.

This section therefore focuses on periods of tighter adequacy margins, that is, when the system has fewer resources available to maintain energy balance. The objective is to present how generation dispatch and cross-

border exchanges adjust under such conditions, and to quantify the associated impacts on electricity prices and carbon emissions.

The analysis focuses on extreme meteorological conditions affecting both supply and demand. Meteorological variability is assessed by applying 11 historical weather years (2006–2016) to the 2026 generation mix, demand levels and price assumptions. Weather conditions influence electricity demand through heating and cooling needs, variable renewable generation profiles and load factors, and hydro resource availability²⁷. Two specific events are selected to illustrate the observed dynamics.

5.1. Stress events result from correlated meteorological extremes across western Europe

5.1.1. Key meteorological drivers are cold spells and *Dunkeflaute* events

Stress events are identified on both sides of the energy balance: they can be demand-driven, when electricity consumption is exceptionally high, or supply-driven, when available generation is unusually low. These situations may also occur simultaneously and reinforce their impact. In this study, the two categories are analysed separately. Events are identified across the 11 weather sensitivities for each price zone using quantitative thresholds.

1. **Peak Demand events** are defined as a prolonged period of high electricity demand. In Western Europe, such events typically correspond to cold spells, during

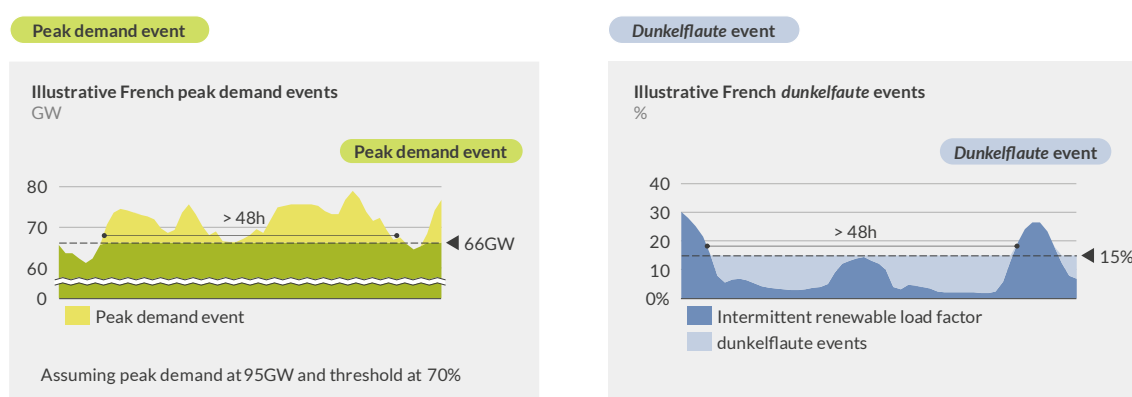
which heating needs maintain demand at high levels. In this report, a peak demand event is characterised by demand exceeding 70% of the maximum demand observed across all weather sensitivities in that price zone, for at least 48 consecutive hours. For France, where maximum demand reaches up to 95GW under the 2026 demand assumptions, this corresponds to at least two consecutive days with demand continuously above 66GW.

²⁷ See section 2 for further details on weather year significations.

2. **Dunkelflaute**²⁸ events are defined as a period of sustained low VRE output. With limited solar and wind generation available, the supply stack becomes narrower, and the system must rely more heavily on available technologies higher in the merit order. In this report, a *Dunkelflaute* event corresponds to

at least 48 consecutive hours during which VRE combined load factor is below 15%. For Germany, considering an installed capacity of 200GW in 2026, this implies that hourly wind and solar total output would remain below 30GW for more than 48 hours.

Figure 25 - Thresholds allow systematic identification of stress events across the eleven weather sensitivities (2006–2016)



Source: Aurora Energy Research (2026)

Across the eleven sensitivities under which the 2026 power system is simulated, a total of 454 stress events are identified across the six focus regions²⁹:

- **118 peak-demand events**, including **26 in France**
- **336 Dunkelflaute events**, including **22 in France**

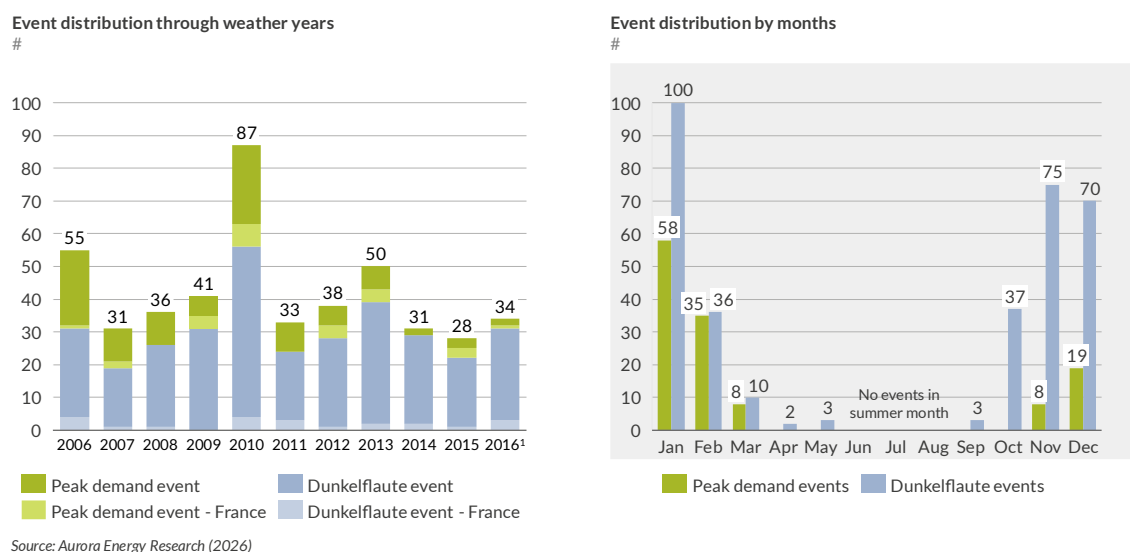
These events tend to last well beyond the 48-hour threshold. *Dunkelflaute* events have an average duration of **91 hours (3.8 days)**, while *Peak Demand* events last on average

111 hours (4.6 days). Their occurrence is highly seasonal, with most events for both categories concentrated around Winter months between October and March. Furthermore, strong interannual variability is observed. Under 2015 weather conditions, 28 events are identified, compared with 87 events under 2010 conditions, with no clear trend across years. This distribution shows that these events represent recurring seasonal risks for the power system whose frequency remains uncertain from year to year.

²⁸ *Dunkelflaute*, German for 'dark lull' (darkness and calm), is a period of very low wind and solar energy generation.

²⁹ If a peak-demand event occurs simultaneously in two countries, it is counted as two distinct events, and it is very likely that their exact timing and duration will differ.

Figure 26 - Extreme meteorological stress is highly seasonal, concentrated in winter with a strong inter-annual variability³⁰



5.1.2. These meteorological events translate into system stress characterised by high costs, emissions and adequacy risks

Although they affect different sides of the energy balance, peak-demand and *Dunkelflaute* events lead to similar market outcomes. In a peak-demand event, the demand curve shifts to the right³¹. In a *Dunkelflaute* event, low wind and solar output removes low marginal cost generation from at the left end of the supply stack. Given a constant demand, this produces an equivalent effect: technologies located further to the right of the merit order are activated. In both situations, this implies that higher marginal costs units are activated. As these events typically occur in winter, when demand is already high, the remaining available capacity often consists of fossil-fired plants, particularly peaking gas and oil units.

- Electricity prices increase sharply. In France, wholesale day-ahead prices during stress events are on average 71% higher than the annual average, reaching 111 €/MWh compared with

65 €/MWh over the year. A similar pattern is observed across other countries, where average prices exceed 100 €/MWh during both types of events.

- Carbon emissions rise even more strongly. Direct CO₂ emissions increase by more than 50% across all countries, including France, compared to yearly average. The largest absolute increase occurs during *Dunkelflaute* events in Germany, where carbon intensity rises by 152gCO₂/kWh to reach 443gCO₂/kWh. That is roughly ten times higher than the average level observed during similar events in France, illustrating how strongly stress-event emissions depend on the underlying generation mix and, in particular, the relative weight of fossil capacity in the system.

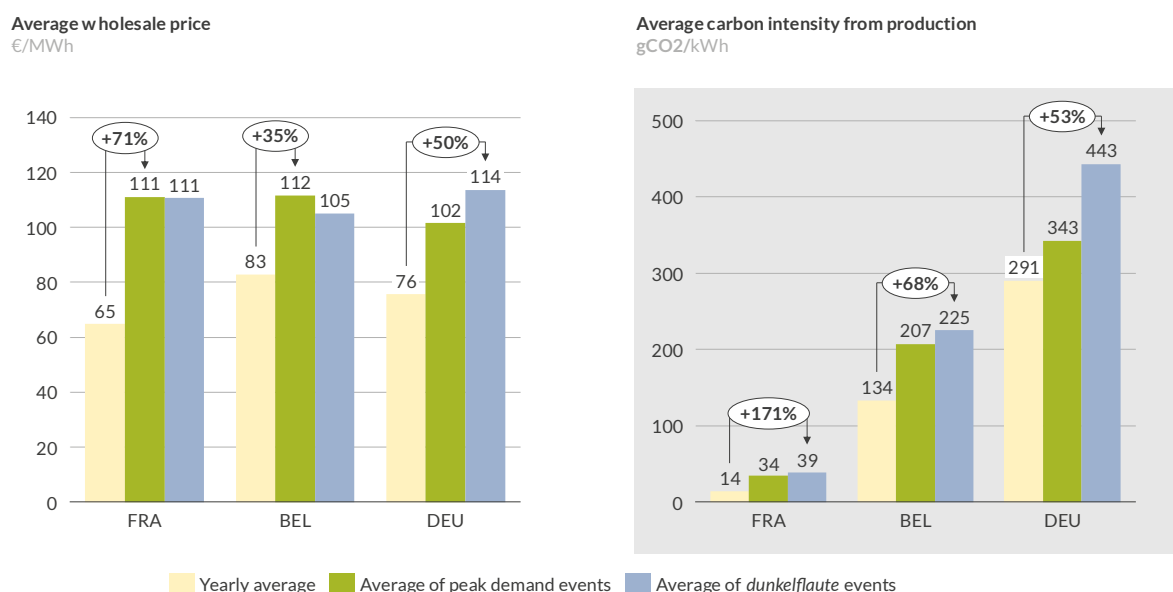
³⁰ The events are identified independently for each bidding zone, therefore an event occurring over several geographies will be recorded once for each of them.

³¹ See market clearing mechanism figure in section 3.3

Weather-driven stress events place electricity systems under strain, raising power prices and slowing progress toward

European decarbonisation objectives. That is why understanding these episodes is key to strengthen system resilience.

Figure 27 - Stress events raise power prices and increase carbon emissions



5.1.3. Spatial correlation of weather regimes amplifies system-wide adequacy challenges

This study places a particular attention to **cross-zonal interactions in electricity markets and on the role of interconnections during system stress**. Hence, when a stress event occurs in one region, the study looks at how a neighbour region can support the system stress by importing or exporting energy. However, meteorological events rarely happen in regional isolation, with cold spells or periods of low wind often impacting multiple regions at once. This can result in an

amplified system stress, as countries cannot rely as much on their neighbour's flexibility to cover domestic system tightness.

To measure whether a stress event occurs in isolation or across several regions, a synchronicity index is defined. For a given event occurring in a host country (zone A), and for a neighbouring country (zone B), the index measures the share of hours during which zone B also reaches the predefined stress threshold.

$$Synchronicity(event, B) = \frac{\text{Number of stress hours observed in zone B during the event in zone A}}{\text{Number of hours of the event observed in zone A}}$$

For example, if a 60-hour *Dunkelflaute* event is observed in France and the exact same event is observed in Germany, the

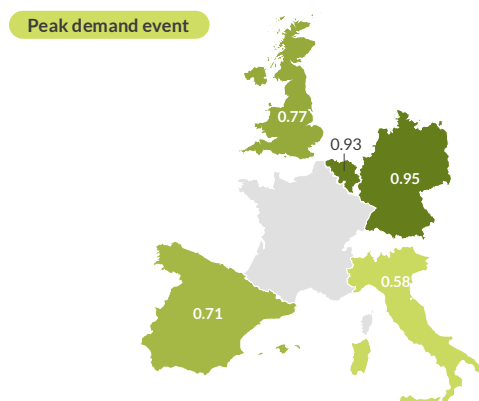
synchronicity index will be 1. Even if the event in Germany lasts 10 hours longer, it will still result in a synchronicity index of 1

from the perspective of the French event. Conversely, if this stress event is confined to France and the considered neighbour has a combined solar and wind load factor consistently above 15%, the synchronicity index will be 0. The closer the synchronicity index is to 1, the more the stress event occurring in one region is simultaneously experienced in the neighbouring region.

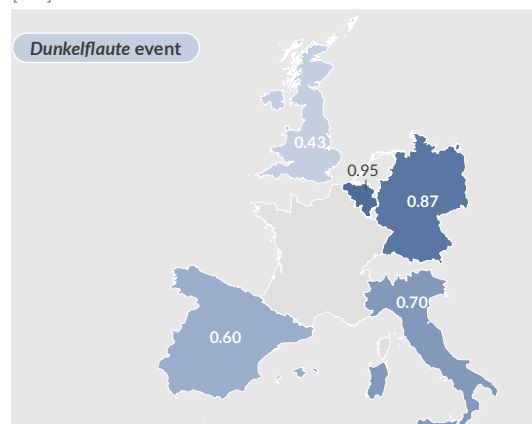
Considering all French stress events, the average of the synchronicity index across the five studied neighbours reaches 0.63 for peak-demand events and 0.65 for *Dunkelflaute* events, with particularly high values for Germany. Both categories of events tend to coincide with high levels of synchronicity across Western Europe.

Figure 28 - Average synchronicity across stress events is high, with events hitting France being highly correlated with Germany and Belgium notably

French Peak demand event average synchronicity [0-1]



French *Dunkelflaute* event average synchronicity [0-1]



Source: Aurora Energy Research (2026)

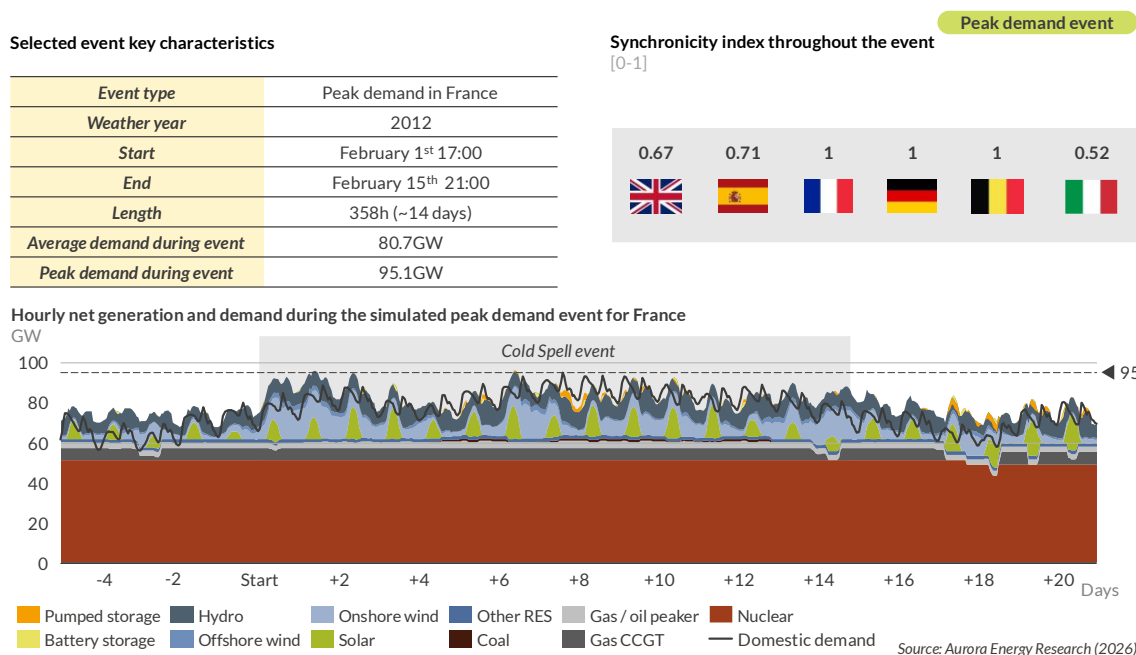
5.1.4. Stress event dynamics are illustrated through two selected case studies

To further understand system response and its economic and environmental consequences during stress events, two specific cases are selected. These case studies serve as concrete examples that allow system behaviour, interdependence, and vulnerabilities to be analysed more closely.

The selected peak-demand event corresponds to the major cold spell that affected France and Western Europe in February 2012, during which French electricity consumption reached an all-time

record of 102GW. When applied to the 2026 power system assumptions, this episode still results in particularly high electricity demand. Over the event 358 hours (approximately 14 days), demand remains above 70% of the simulated annual maximum. Average demand over the period reaches 80.7GW, corresponding to 83% of the simulated annual peak demand of 95.1GW. The lower peak observed under the 2026 assumptions compared to the actual event reflects the structural decline and following stagnation of electricity demand over the past 15 years.

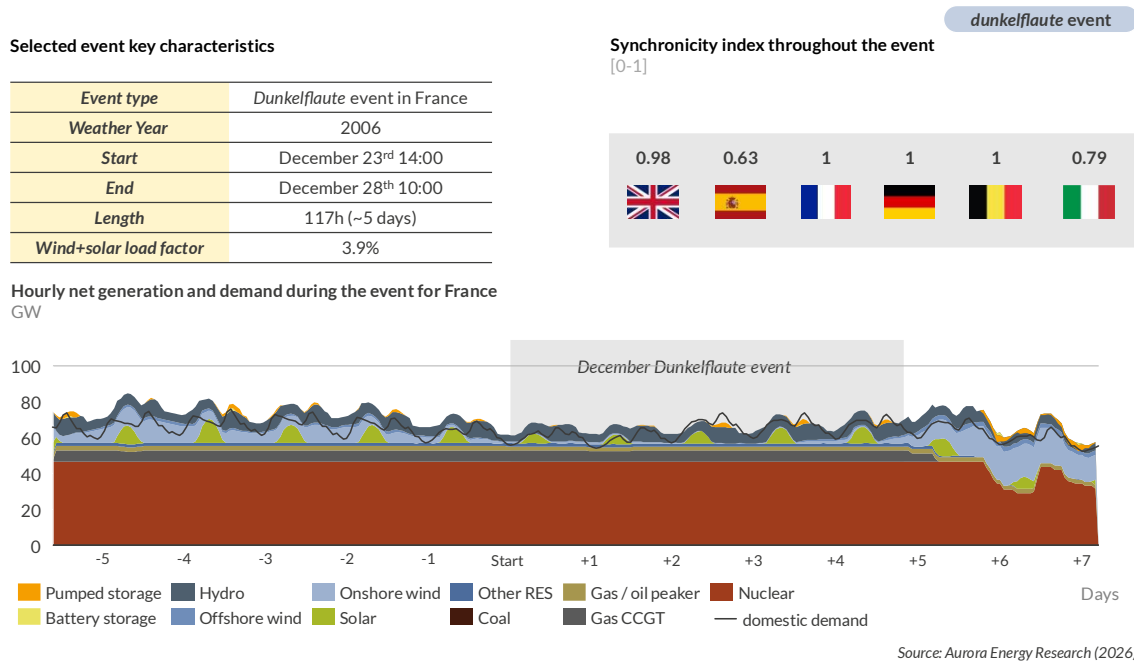
Figure 29 - The selected peak-demand is a simulation of the 2012 cold spell applied to the 2026 power system



The selected *Dunkelflaute* event corresponds to a **prolonged period of very low wind and solar generation observed from 23 December to 28 December 2006**. When applied to the 2026 power system assumptions, this episode results in a sustained variable renewables production deficit. The event lasts 117 hours, or nearly five days. During this period, France

experiences a combined wind and solar load factor of 3.9%, illustrating the severity of the conditions and the resulting stress on the energy system. Neighbouring countries are also affected, with an average synchronicity index of 0.78. In the following sections of the report, this episode is referred to as the “*Dunkelflaute* event”.

Figure 30 - The selected *Dunkelflaute* event is a simulation from 2006 Christmas week applied to the 2026 power system.



5.2. These events demonstrate the importance of dispatchable capacity and cross-border integration

In section 4.1.1 of this report, residual demand is presented as a highly relevant indicator for assessing dispatchable capacity needs. Analysing residual demand during the selected events helps quantify the scale of system stress compared with annual or even winter averages:

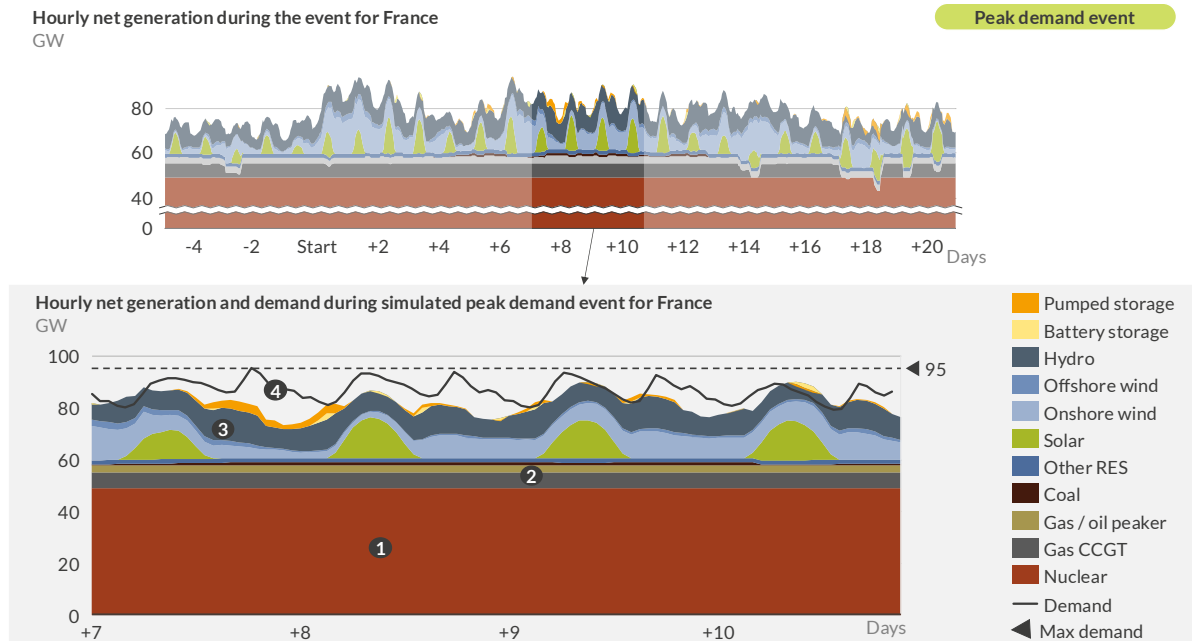
- For the peak-demand event, average residual demand reaches 69GW, significantly above the winter average

residual demand of 50GW in the Central scenario.

- For the December *Dunkelflaute* event, residual demand reaches 60GW, still well above winter average levels. Even though demand is lower than in the peak demand event, only 6% of generation is met by renewables during this event, far below the 21% annual average projected for 2026 in the Central scenario.

5.2.1. In the peak demand event, peaking units ramp up and France turns net importer

Figure 31 - Domestic response in France in a peak demand event results in heightened use of storage solutions and some coal activation



Source: Aurora Energy Research (2026)

Looking at the generation stack before, during and after the cold spell gives insights as to how the French power system adapts its mix to the stress event.

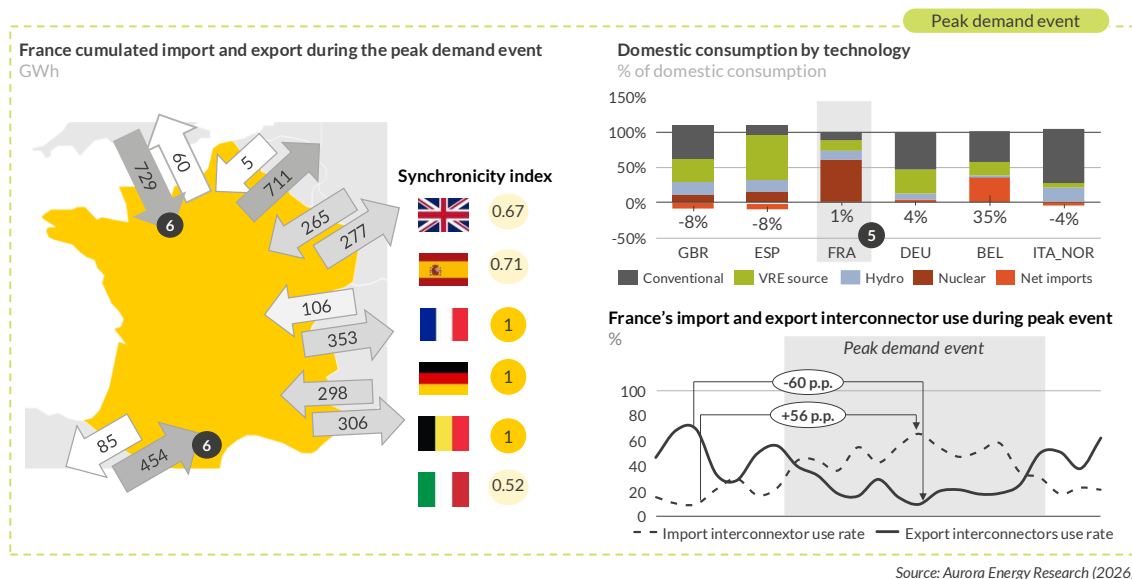
1 Baseload generation is fully dispatched: Nuclear and CCGT units are already operating at 100% of available capacity prior to the cold spell and remain at maximum output throughout.

2 Coal is activated: Coal plants are activated from D+7 as the cold spell intensifies and begin ramping down three days later as demand decreases. In France, coal generation reflects extraordinary supply needs.

3 Storage ramps up: Pumped storage and batteries are further activated at the event peak, with battery injections reaching 2.4GW, close to maximum installed capacity. In this situation, batteries charge overnight when prices are relatively lower, while pumped storage draws on water volumes accumulated prior to the event.

4 Demand reaches its maximum at 95.1GW, relying both on domestic and foreign generation, and French interconnectors flows shift towards imports.

Figure 32 - France becomes a net importer, relying on cross-border exchanges to meet domestic needs in the most economically efficient way.



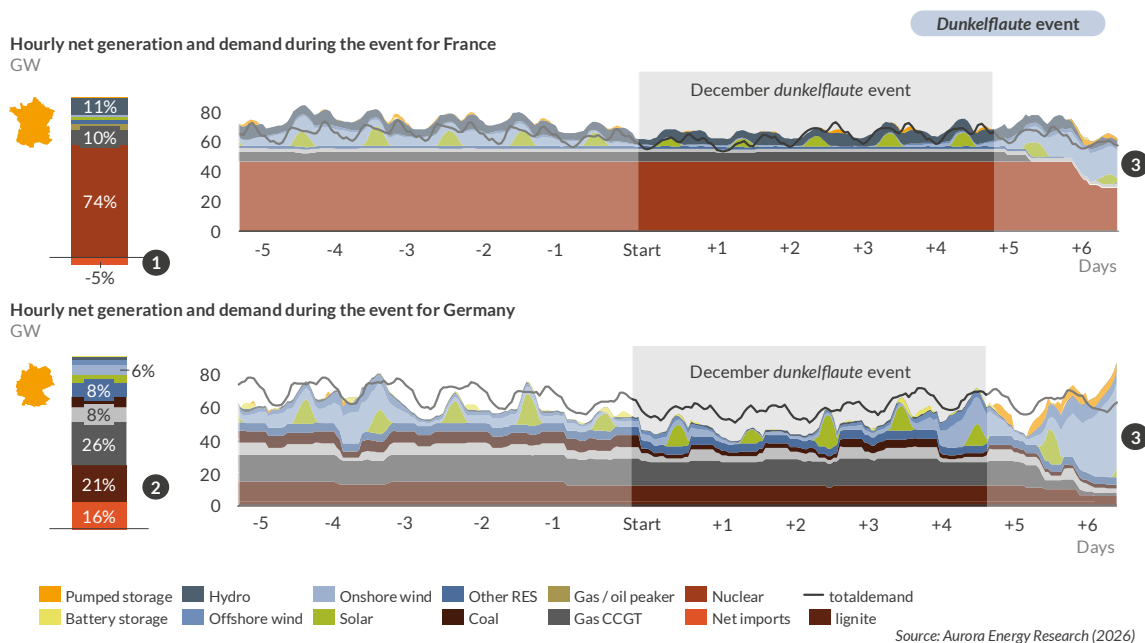
5 France becomes a net importer: During the French peak demand event, the country imports 1% of its consumption. While this number is small, it is still a stark difference from its usual net exporter profile, reflecting how France's system can react under system stress. French export interconnectors average utilisation rates³² drop by 87%, while import interconnectors utilisation increase steadily throughout the event, before dropping back at event end.

6 Great Britain and Spain step up as exporters: As Spain and Great Britain are less affected by the stress event (with synchronicity indexes of 0.67 and 0.71 respectively) and benefit from relatively strong renewable generation, they become significant net exporters. These volumes help cover part of French demand and are further transmitted toward Belgium and Central Europe. In neighbouring regions that are equally affected by the stress event, such as Belgium and Germany, net imports represent a larger share of domestic consumption, reaching up to 35% in Belgium.

³² Across all neighbours

5.2.2. During the *Dunkelflaute* event, France’s dispatchable low-carbon generation limit the activation of more expensive conventional units

Figure 33 - France’s nuclear baseload ensures a high baseload contribution while Germany relies on imports during the December *Dunkelflaute* event



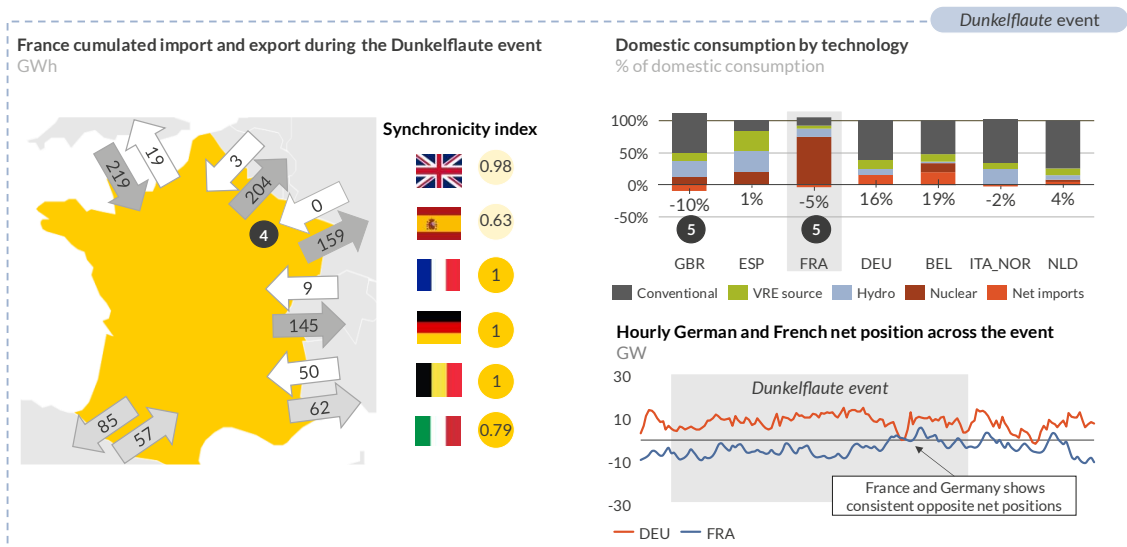
1 France maintains sufficient generation: During the selected *Dunkelflaute* event, the French generation mix remains largely unchanged, as pre-event production is sufficient to meet the higher residual demand caused by low wind and solar output. In the week preceding the event, VRE generation covers around 20% of French demand. During the event, the combined load factor of VRE sources drops to 5%, however, no tension on the supply stack is observed. French nuclear baseload continues to supply over 70% of domestic demand.

2 Germany faces a contrasting dynamic: Before the event, VRE sources supply up to 43% of German generation. This illustrates

that renewables can cover a substantial share of demand even in winter, but also that the system becomes more sensitive to unfavourable weather conditions. During the event, lignite and gas CCGT plants operate close to full capacity, and peaking units cover consumption peaks. In addition, Germany imports a large share of its electricity.

3 Wind recovers at the end of the event: As onshore wind generation start recovering four days after the start of the event, both countries progressively ramp down their dispatchable units.

Figure 34 - French and British dispatchable capacities support Western European regions most sensitive to unfavourable weather conditions



Source: Aurora Energy Research (2026)

4 Germany and Belgium rely heavily on imports: Germany and Belgium experience the strongest impact. Despite small solar spikes around midday, the collapse of wind output combined with low winter solar irradiance leads both countries to rely heavily on imports. Foreign units cover 16% of total consumption in Germany and 19% in Belgium over the event period.

5 France and Great Britain remain resilient and support neighbouring systems: Although France and Great Britain are exposed to the same meteorological conditions, their generation mixes allow them to better withstand the renewable deficit, with nuclear and hydropower able to cover a large share of their domestic demand. As a result, France continues to export around 5% of its generation during the event, while Great Britain exports around 9%.

5.2.3. System adequacy is not at risks during stress events, cross-border exchanges and a strong nuclear generation reduce reliance on most expensive peaking solutions

Imports and exports are decided by market price optimisation within the integrated European market rather than by physical production shortages. High import shares therefore do not necessarily indicate domestic scarcity.

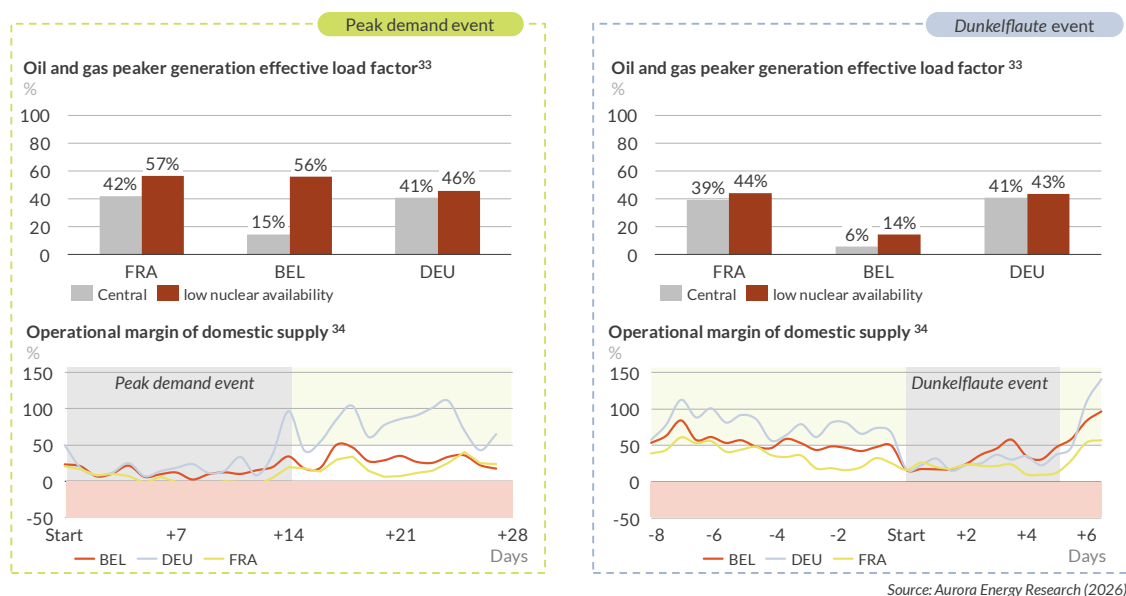
This is confirmed by the load factors³³ of oil and gas peaking plants. Although these technologies are typically the last units activated before demand-side response and represent a limited share of installed capacity (7% in Germany, 6% in Belgium, 4% in France), they are not fully dispatched during stress events. Across all regions, spare peaking capacity remains available.

When nuclear output capacity is reduced in the sensitivity, peaking technologies

utilisation increases but remains well below full activation. The highest observed rate is 57% in France during a peak-demand event. Although utilisation can rise sharply, there is no material risk of unserved demand. The visualisation of the operational margin³⁴ confirms this assessment: margins remain mostly above zero during stress events, and when temporarily negative, the deficit can largely be covered through interconnections.

Overall, in the stress events analysed in this report, security of supply is not a major challenge. While interconnectors provide additional reliability margins, cross-border flows primarily reflect economic optimisation.

Figure 35 - System adequacy is maintained during stress events, with interconnectors and nuclear baseload limiting reliance on most expensive units



³³ Effective load factors is defined as the ratio of the operating capacity over the available capacity. The goal is to measure the real margins of the domestic installed capacity stack.

³⁴ By calculating how much of domestic demand can be covered by available domestic capacity, the operational margin indicates whether the domestic system can support itself self-sufficiently

5.3. During stress events, price levels rise and become more responsive to system and market conditions

The operational responses observed during these demanding system conditions reflect an economic optimisation logic. The analysis now turns to the implications for market prices. Applying the same sensitivities as in

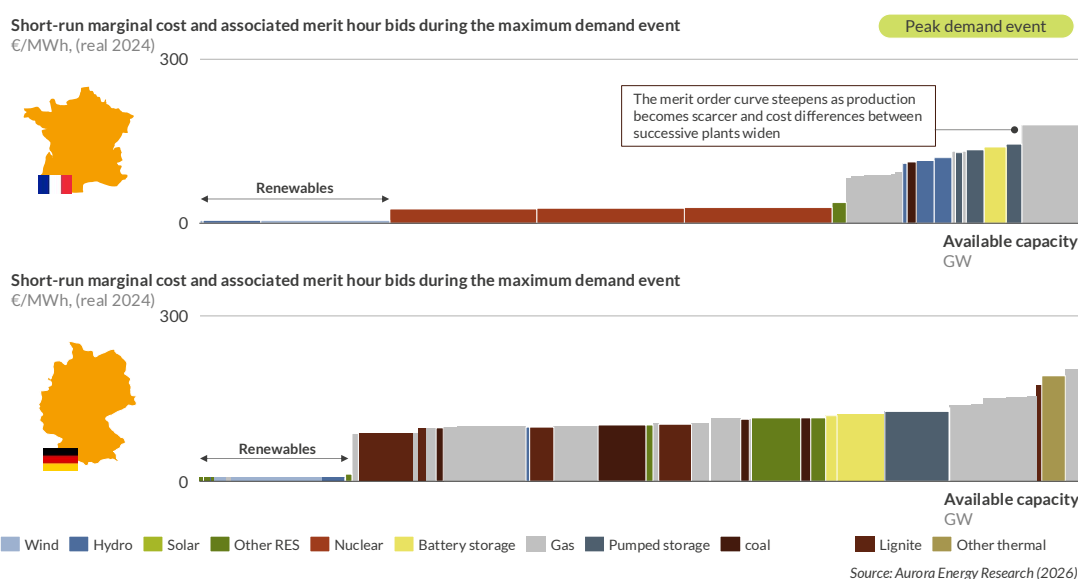
section 4 to the selected stress events offers a direct comparison with annual results and shows how price dynamics change during periods of high dispatchable generation needs.

5.3.1. Day-ahead market is cleared further up the merit order, into steeper segments of the supply curve.

Under stress conditions, dispatchable generation must cover a higher residual demand. Market clearing therefore occurs further to the right along the supply curve. Following the merit-order principle, this implies that plants with higher short-run marginal costs are activated. Since these marginal units determine the clearing price under marginal pricing, overall price levels increase. In the case of France, average day-ahead prices are 60% higher during the *Dunkelflaute* event and 76% higher during the peak-demand event compared with the annual average.

Moving further right along the supply curve also typically corresponds to scarcer and steeper segments: fewer units remain available, and cost differences between successive plants widen. Figure 36 illustrates this observation by presenting the supply curves of France and Germany during the peak consumption hour of the selected peak-demand event, where demand reached 95GW in France. As a result, each additional MWh of demand has a larger impact on the clearing price, increasing price sensitivity to changes in market conditions.

Figure 36 - The marginal technologies are thermal or bid like thermal assets in stress events³⁵



³⁵ These merit order curves represent the peak-demand hour of the event and the scale of the x-axis for the two countries is different.

5.3.2. The French nuclear fleet continues to contain prices regionally, even when it is not marginal

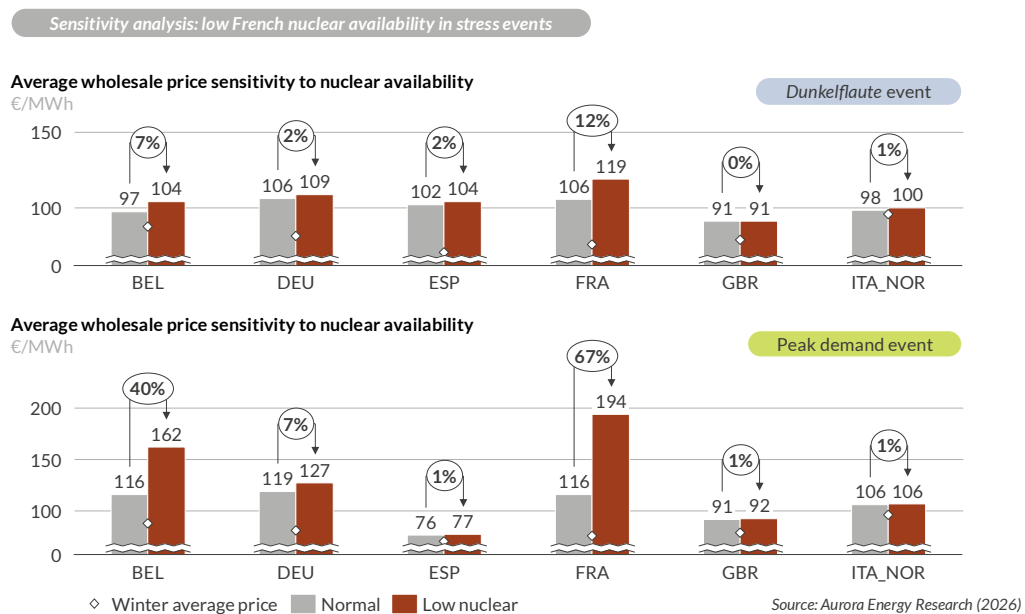
Consistent with the average annual behaviour, lower French nuclear availability amplifies the price increase observed during stress events. Prices rise as nuclear generation declines, with France experiencing the largest impact. During the *Dunkelflaute* event, prices rise by 12%, as observed in Figure 37. Because this event does not coincide with stress on the French supply side, the effects remain moderate and are even smaller than those observed under the same sensitivity applied over the full year.

By contrast, during the peak demand event, the French market clears at the upper end of the merit order. In this case, reducing nuclear generation leads to a surge in the average price of +67% over the event (Figure 37, bottom panel). Considerably more expensive peaking plants need to be activated. French prices reach an average of

194 €/MWh, well above the levels observed in the other selected price zones. This example illustrates the growing sensitivity of prices as dispatchable capacity must cover more extreme residual demand.

France's nuclear fleet also dampens price increase in interconnected importing regions during stress events. During the *Dunkelflaute*, France is initially a large net exporter. The price increase resulting from lower nuclear generation is indirectly transmitted to importing countries such as Belgium and Germany. And this stabilising role of nuclear output is not limited to situations in which France is a net exporter. During the peak demand event, France becomes a net importer, yet Belgium and Germany, which also rely on imports, experience sharp price increases when French nuclear output is reduced.

Figure 37 - Sensitivity analysis shows that low nuclear availability increases stress-event average prices in France and for neighbours



Importantly, in neither case is nuclear the marginal technology. Nevertheless, strong French nuclear generation limits the dispatch of the highest marginal-cost units

in the regional merit order. Even when not price-setting, nuclear output exerts a price-containing effect through its impact on the overall supply curve.

However, the large difference in price outcomes between central and reduced nuclear availability also reveals France’s heightened vulnerability when its nuclear

fleet underperforms and the system becomes more reliant on imports and most expensive peaking plants to meet domestic demand.

5.3.3. But the containment effect of nuclear against commodity price shocks does not extend to stress conditions

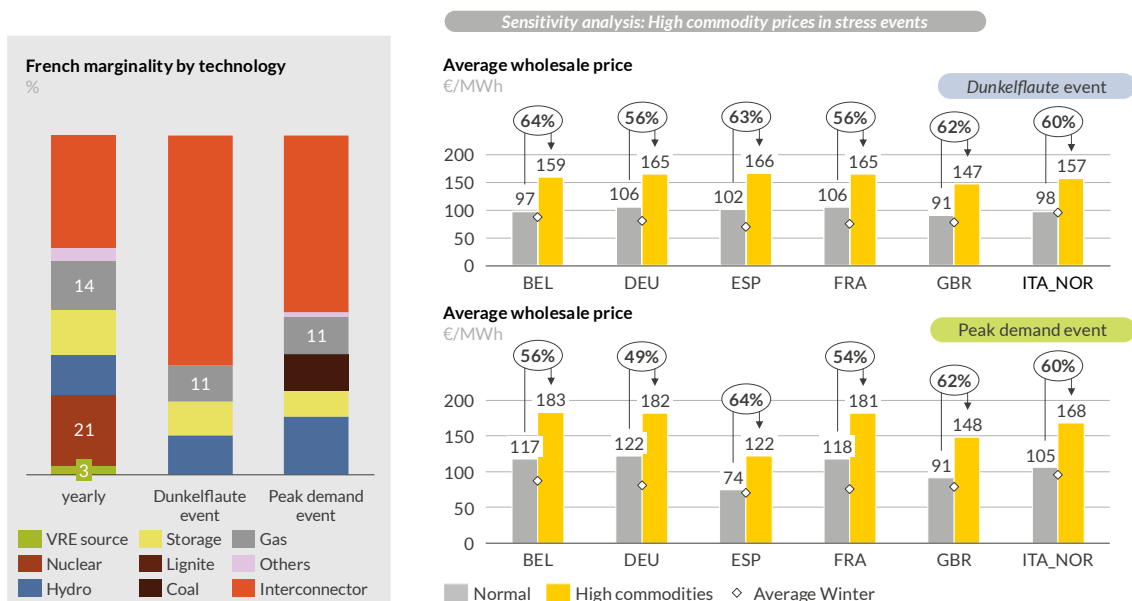
During stress events, characterised by high residual demand, the lowest-cost technologies at the bottom of the merit order operate at their maximum available capacity. In France, nuclear generation therefore runs as baseload, while higher-cost technologies are continuously dispatched to meet additional demand.

Throughout the 117 hours of the *Dunkelflaute* event and the 358 hours of the peak demand event, nuclear never sets the market price, as shown on the left graph of Figure 38 - Nuclear is never marginal during stress events, cancelling the buffering effect against volatile commodity prices observed over an entire year. The buffering effect described in section 0, linked to nuclear being marginal in 21% of annual hours, does not materialise during these periods. Instead, prices are determined primarily by fossil-fired and

storage units, located either domestically or in interconnected neighbouring zones. We see on this on the graph where interconnectors set the hourly day-ahead price in France respectively 68% in the *Dunkelflaute* event and 52% in the peak demand event, compared to 33% of hours on average annually. This shift is reflected in the marginal mix observed under stress conditions.

Because the bidding costs of these technologies are directly linked to fuel and carbon prices, wholesale prices increase mechanically when commodity costs rise. As a result, during the selected stress events, French prices display a similar sensitivity to commodity price increases as those observed in other studied countries, with average prices rising by approximately 50%.

Figure 38 - Nuclear is never marginal during stress events, cancelling the buffering effect against volatile commodity prices observed over an entire year (Section 4.4.3)



Source: Aurora Energy Research (2026)

5.4. Emissions increase significantly during stress events, with nuclear availability crucial for limiting carbon intensity

Stress events are characterised by higher activation of thermal generation, which results in higher carbon emissions compared to reference annual conditions. The average carbon intensity of the electricity consumed across the six price zones increases from 116gCO₂/kWh in the reference year to 172gCO₂/kWh during the *Dunkelflaute* event and 187gCO₂/kWh during the peak demand event.

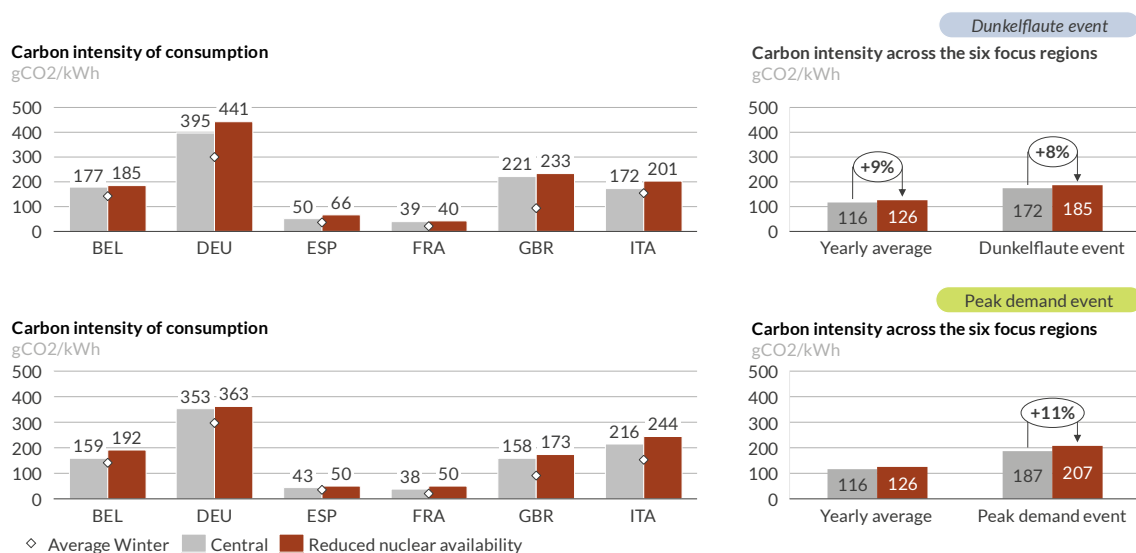
However, significant disparities persist across price zones. In the simulation, the highest average carbon intensity is observed in Germany during the *Dunkelflaute* event, reaching 441gCO₂/kWh, driven by the extensive use of hard coal and lignite plants, the most carbon-intensive technologies. At the other

end of the spectrum, French consumption remains the least carbon-intensive, at close to 40gCO₂/kWh in both events.

During stress events, each additional MWh of low-carbon electricity directly displaces fossil-based generation. Thanks to its dispatchable nature and flexible maintenance scheduling, the French nuclear fleet can operate at high load factors during constrained periods, ensuring substantial volumes of low-carbon supply during these periods.

Moreover, its impact extends beyond France, and the benefits are regional. During the 5-day *Dunkelflaute* event, reduced nuclear availability increases overall emissions by 8%, and by 11% in the 15-day peak demand case.

Figure 39 - France's nuclear fleet provides a stable low-carbon baseload, partially limiting regional emissions during periods of low renewable output



Source: Aurora Energy Research (2026)

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