Le réseau
de transport
d'électricité

# 2025 ELECTRICITY REVIEW

## FULL REPORT

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## APPENDICES

# Consumption

2025 ELECTRICITY REVIEW

## Consumption remained stable in 2025 at a lower level than pre-crisis

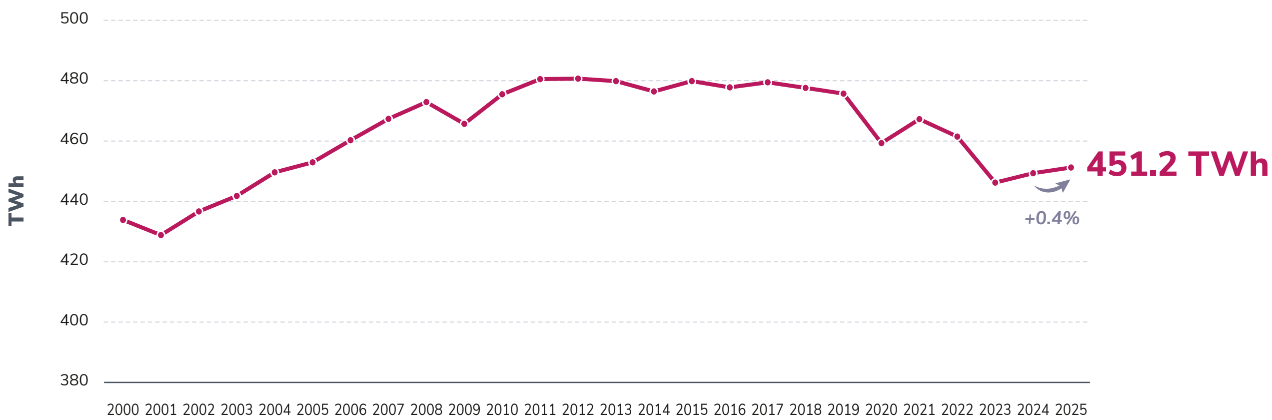
**Electricity consumption in mainland France[1], adjusted for weather and calendar effects, remained stable in 2025 in comparison with the previous year, reaching 451 TWh** (+0.4% compared with 2024).

The downward trend caused by the energy crisis, which led to significant falls in electricity consumption in 2022–2023, came to a halt in 2024. Since then, however, there has been no recovery in consumption to match what occurred after the financial crisis in 2008–2009 or the pandemic in 2020.

**Consumption thus remained around 6% below the level seen over the 2014–2019 period (before the Covid pandemic and the energy crisis):** the continuing repercussions of the energy crisis and the uncertain geopolitical context, particularly with regard to industrial activity, as well as progress in energy efficiency, are tending to offset the low level of electrification of energy use.

**The drop in consumption in 2023 was among the most significant since the end of the Second World War:** it was close to the reduction caused by

**Figure 1.1 – Consumption adjusted for weather and calendar effects between 2000 and 2025**




1. Scope: mainland France, excluding uranium enrichment. The values shown exclude consumption due to uranium enrichment in France, to ensure that levels are comparable over time. A change in the process used meant that enrichment consumption fell sharply from 2012 onwards.

the pandemic in 2020 and more significant than the fall due to the economic crisis in 2008–2009.

After a partial recovery in 2021 following the pandemic, consumption took an initial hit in 2022, at the height of the energy crisis. The fall in consumption intensified in 2023, driven mainly by residential and tertiary consumers. The protective measures put in place by the government limited the impact of high electricity prices on residential and small business consumers at the height of the crisis in 2022. Nevertheless, regulated tariffs rose twice in 2023 (+15% in February, +10% in August), and then by a further 10% in February 2024. A third of small business customers and 58% of households were on the TRVE[2] regulated tariff in 2024. Industry was also more affected in 2023, particularly in electricity-intensive sectors.

**Electricity consumption stopped falling in 2024, thanks to an improved macroeconomic context compared with 2023.** This is because energy prices (both gas and electricity) fell sharply in 2024, approaching pre-crisis levels, and inflation also fell significantly compared with 2022 (when it stood at +5.2%) and 2023 (+4.9%), settling at 2.0%[3]. This stability in 2024 resulted from several contrasting trends: while consumption increased for large industrial consumers (and rail transport) connected to the transmission network, it continued to fall for industrial consumers connected to the distribution network, and remained stable for residential and tertiary consumers. The majority of medium-sized and large businesses depend on market offers, while those with the highest consumption can also obtain supplies directly from the wholesale markets, which means they react more quickly to changes in electricity prices on these markets. Consumption by industries supplied by the public distribution network, on the other hand, was particularly affected by the slowdown in activity in sectors such as rubber products and machinery and equipment manufacturing, and by persistent difficulties in the automotive industry due to supply problems. Industrial production indices fell by 5%, 8% and 14%[4] respectively in these three sectors in 2024 compared with 2023.

**Figure 1.2 – Breakdown of variations in final electricity consumption in mainland France between 2021 and 2024 (values adjusted for weather and calendar effects)**

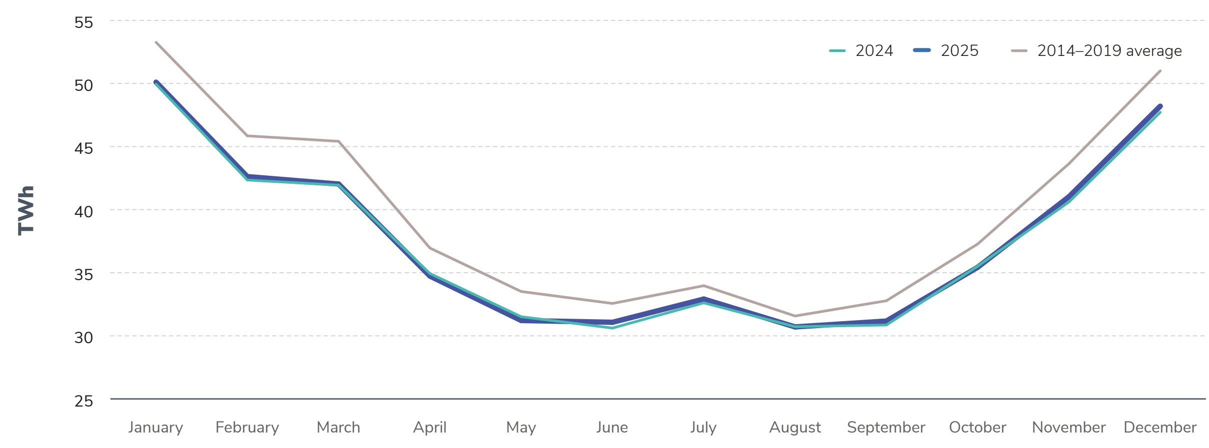

* Consumers connected to the transmission network, including rail transport.

2. CRE, *Fonctionnement des marchés de détail français de l'électricité et du gaz naturel en 2023 et 2024*, October 2025
3. INSEE, *Further slowdown in annual average consumer prices in 2025 – Informations rapides No. 8*, January 2026
4. RTE calculations based on INSEE data, SA-WDA *Industrial production index*, published on 05/02/2026.

**Consumption remained stable in 2025 despite an environment characterised by significant geopolitical uncertainty,** including the results of the United States introducing tariffs at unprecedented levels. The French economy demonstrated a degree of resilience, with a slightly lower growth rate than in 2024 (+0.9% according to INSEE[5], compared with +1.2% the previous year), and business investment seemed to be showing positive signs at the end of 2025. Inflation slowed sharply[6] (to +0.9%), due in particular to the fall in electricity prices (11.9% on average, after +15.7% in 2024) according to INSEE. Regulated electricity tariffs (TRVE[7]) fell by 15% in February. However, domestic commercial and political uncertainty penalised household consumption, and the household savings ratio remained high (18.7% in the second quarter and 18.4% in the third quarter of 2025 compared with an average of 14.6% over the 2010–2019 period)[8]. Similarly, the household confidence indicator deteriorated in 2025 compared to 2024[9].

**The electrification of energy uses, which should follow from the decarbonisation of the French economy and from the country's reindustrialisation, appears to be lagging behind the projected pathway to achieve France's climate objectives.** Electricity as a proportion of final energy consumption has remained stable overall for many years, a sign that the switch from fossil fuels to low-carbon energy, and electricity in particular, has not yet found its momentum. While the development of electric vehicles and heat pumps is continuing, the rate of change in energy use remains lower than the speed required to achieve the *Fit for 55* targets by 2030. At the same time, a number of electrification projects in industry have secured grid access for the coming years, but these are currently proving slow to materialise (see *Electrification* chapter).

**Figure 1.3 – Consumption adjusted for weather and calendar effects**




5. INSEE, *GDP slowed down in Q4 2025 (+0.2% after +0.5%); on average in 2025, it increased by 0.9% – Informations rapides No. 25*, January 2026
6. INSEE, *Further slowdown in annual average consumer prices in 2025 – Informations rapide No. 8*, January 2026
7. TRVE: These regulated electricity tariffs are calculated on the basis of the average electricity prices on the wholesale markets over the last 24 months, which is why there is a delay in adjusting to any fall in the markets.
8. INSEE, *Moderate consolidation and renewed growth – Economic Outlook December 2025*, December 2025
9. INSEE, *Focus – In France, households are much more pessimistic about the country's future economic situation than before the pandemic, but their opinion about their personal situation has not changed – In INSEE, Moderate consolidation and renewed growth – Economic Outlook December 2025*, December 2025

As far as domestic customers are concerned, energy bills still represent a higher proportion of household incomes than before the energy crisis[10] despite the fall in electricity prices for consumers. According to a survey carried out by the French energy ombudsman in September 2025[11], nearly 36% of households said they found it difficult to pay their energy bills in 2025, compared with 28% in 2024. In the same survey, 85% of households said they were adopting energy-saving measures, mainly for financial reasons (87%). French households are also choosing other approaches, such as self-consumption and making the most of flexible consumption (summer/winter off-peak times, weekend off-peak times, TRVE “TEMPO” option), to help control their energy bills[12]. In addition, at the height of the crisis, some suppliers began to encourage their customers to reduce their energy consumption by rewarding them with bonuses or incentives. This type of offer came to an end after the effects of the crisis eased.

The trends described for electricity consumption in France include self-consumption (direct consumption of all or some of the electricity generated by the consumer), which has developed in France thanks to the falling cost of solar panels and the growing desire of households, businesses and local authorities to control their bills and help meet environmental targets[12]. The energy crisis has accentuated this trend, which is largely driven by households. Since 2018, most new residential solar panel installations have been operating on a full or partial self-consumption basis. The number of solar self-consumption installations had risen from nearly 40,000 at the end of 2018 to almost 850,000 (including 838,000 for households and small businesses) by the end of 2025[13], representing 5.4 GW of total capacity (including 3.7 GW for households and small businesses), or 18% of the total solar capacity installed in France (30.4 GW at the end of 2025). The volume of self-consumed energy was around 2.9 TWh[14] in 2025, compared with 2 TWh in 2024, an increase of 45%.

10. CRE, *Fonctionnement des marchés de détail français de l’électricité et du gaz naturel en 2023 et 2024*, October 2025
11. Médiateur National de l’Énergie, *Baromètre énergie – info 2025 : La facture d’énergie, une préoccupation de plus en plus ancrée chez les ménages*, October 2025
12. CRE, *Fonctionnement des marchés de détail français de l’électricité et du gaz naturel en 2023 et 2024*, October 2025
13. Enedis – Open Services & Open Data, *Parc raccordé*, January 2026
14. RTE estimates

# Gross consumption also remained stable, with a higher level at the beginning of the year

Gross French electricity consumption also remained relatively stable in 2025 at 446.1 TWh, rising +0.9% from the previous year.

Gross consumption was higher in the first quarter due to the temperature sensitivity of consumption. Temperatures were lower than in the first quarter of 2024 (–1.2°C on average, resulting in an increase in consumption of almost 6 TWh over the quarter).

The difference with the same month in 2024 was most significant in February, when the average temperature differential was greatest. However, the annual consumption peak was recorded on 14 January at 9 am (during the morning peak load). **Despite the stagnation in consumption, peak consumption in 2025 reached its highest level since 2021, at 88 GW.**

**Figure 1.4 – Gross consumption (not adjusted for weather and calendar effects) compared with adjusted consumption between 2000 and 2025**

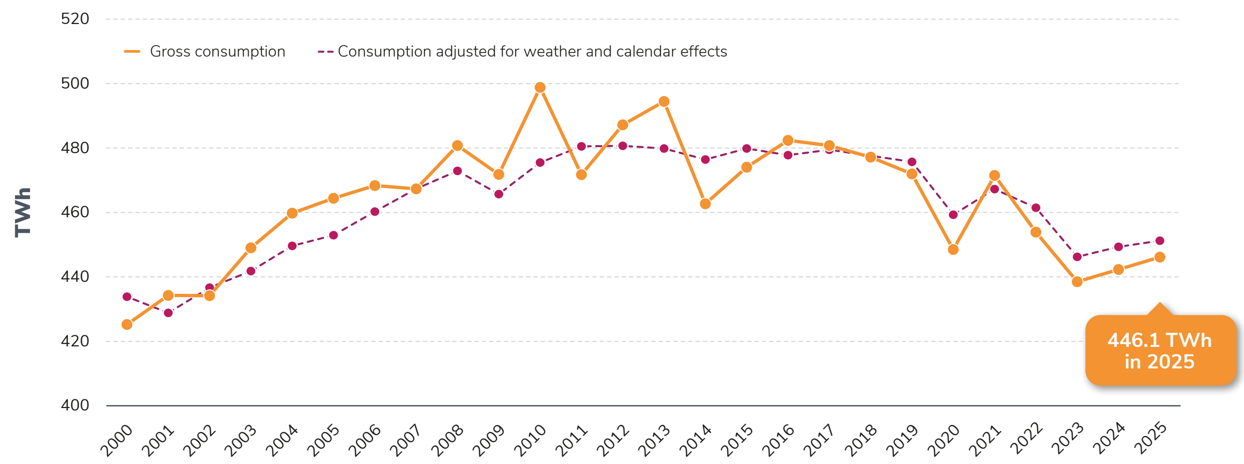
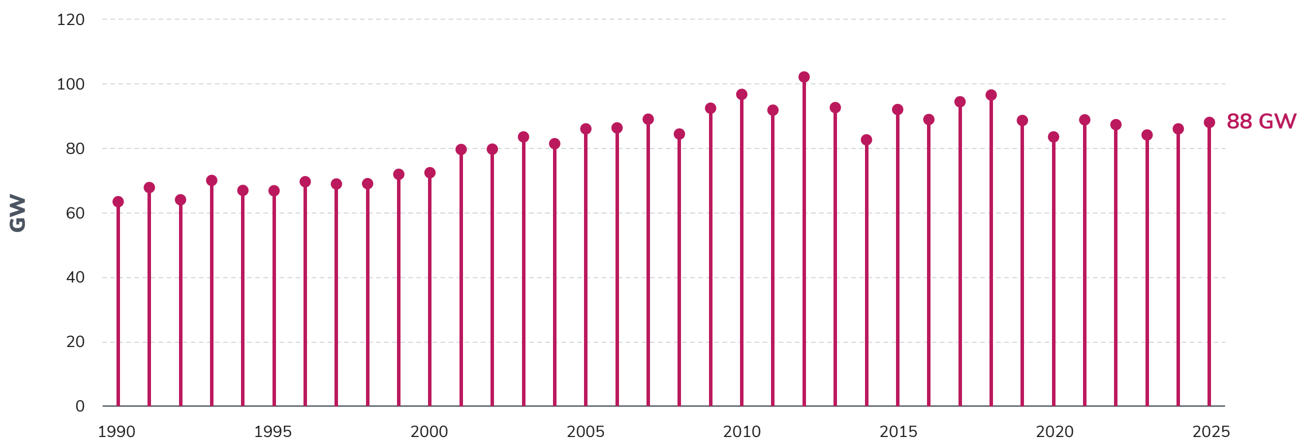



**Figure 1.5 – Annual gross consumption peak values between 1990 and 2025**



During the summer, the heat wave[15] that occurred in the second half of June also caused a one-off increase in consumption due to the use of air conditioning[16]. The temperature sensitivity of French consumption is mainly concentrated in winter due to heating, but it also occurs to a lesser extent in summer during prolonged periods of intense heat. This type of episode has been on the increase in recent years. According to Météo France, the summer of 2025 had the second highest number of heatwave days after 2022, with 33. However, France remains much less temperature-sensitive at this time of year than southern European countries such as Spain or Italy (see the analysis of cross-border trade with Spain in the *Trading*chapter).

Like adjusted consumption, gross consumption remained at a historically low level. Together with the abundance of French electricity generation (see the *Generation* chapter), especially low-carbon generation, this explains the record export balance achieved in 2025 (see the *Trading* chapter).

**Figure 1.6 – Temperature in 2025 and deviation from normal temperature**

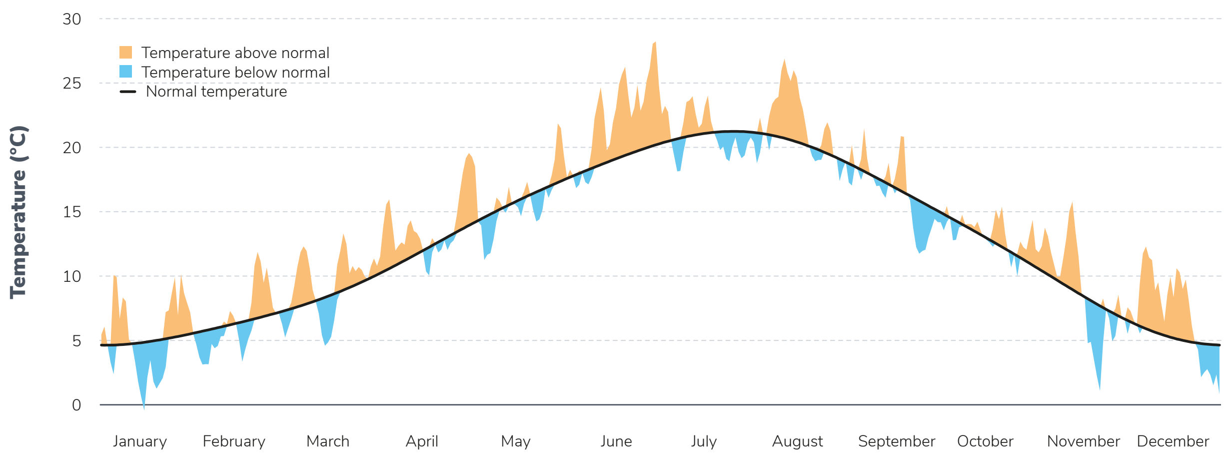
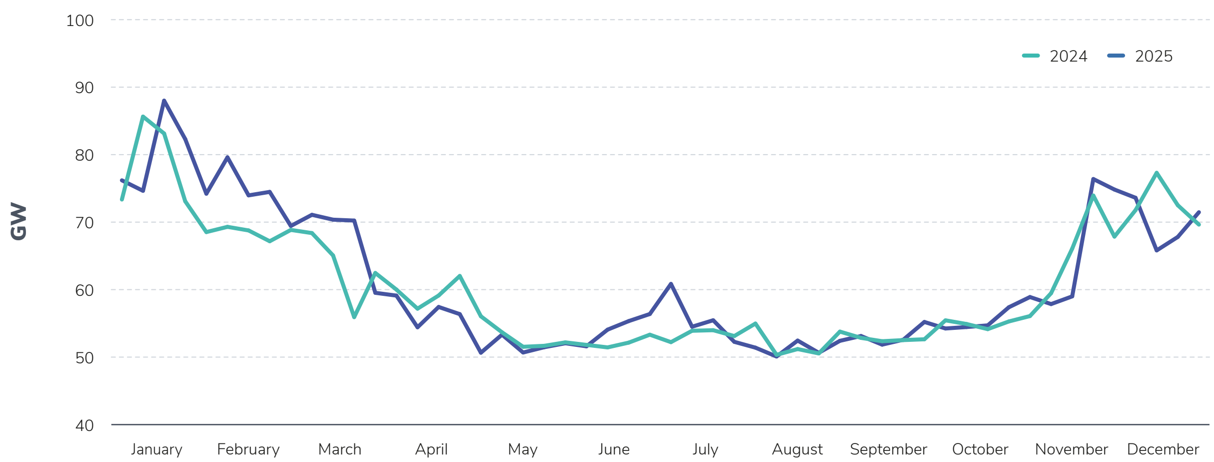



**Figure 1.7 – Maximum weekly consumption in 2024 and 2025**




15. Météo France, 2025 : *les bilans climatiques*, January 2026
16. SDES, *Des consommations d'énergie dépendantes des conditions météorologiques*, February 2025

FOCUS

## Definitions

**Gross consumption:** consumption not adjusted for weather and calendar effects. This includes self-consumption and losses, but excludes PSH pumping consumption and consumption by power station generation auxiliaries. The geographical scope considered in the Electricity Review is mainland France and Corsica.

**Adjusted consumption:** this is the gross consumption corrected to take account of weather, particularly with regard to temperature sensitivity, calendar effects and load shedding. This makes it easier to track underlying trends linked to the structural determinants of changes in consumption.

**Final consumption:** this is electricity consumption by end users (industry, housing, tertiary activities, agriculture). It excludes losses on the transmission and distribution networks. It can be gross or corrected for weather, calendar effects and load shedding.

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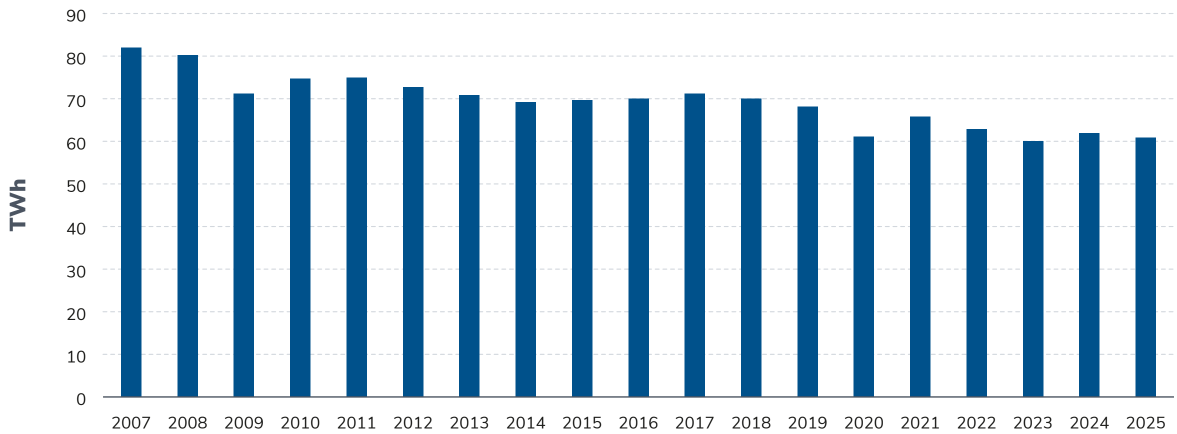
## Reconstituting gross consumption

Gross consumption can be reconstituted on the basis of electricity generated and traded with neighbouring countries. It corresponds to the difference between national net electricity generation on one hand (across the whole mix, net of consumption by auxiliaries and taking self-generation/self-consumption into account) and consumption due to pumping by pumped-storage hydropower installations added to the balance of physical exchanges of electricity. It is worth noting that the balance of physical exchanges differs slightly from the balance of commercial trade due to the inclusion of physical flows to and from certain areas connected to the French network but located outside France (such as the islands of Jersey and Guernsey) and other minor differences in scope. Gross consumption (like consumption adjusted for weather and calendar effects) includes losses due to the transport of electricity through the transmission and distribution networks. For 2025:

| Net generation (including self-consumption) | – | Pumping consumption | – | Commercial export balance | – | Difference in export balance between physical exchanges and commercial trade | = | Gross consumption (including self-consumption) |
|---|---|---|---|---|---|---|---|---|
| **547.5 TWh** | | **8.1 TWh** | | **92.3 TWh** | | **1.0 TWh** | | **446.1 TWh** |

# Consumption by large consumers connected to the PTS fell amid economic conditions that are weighing on businesses

**Figure 1.8 – Electricity consumption by consumers connected to the public transmission system***




** Excluding uranium enrichment*

**Consumption by major consumers connected to the public transmission system (PTS), most of which are in the industrial sector, fell by 1.7%[17] in 2025 as a result of the macroeconomic context, which was marked by strong geopolitical uncertainty and increased international competition.** The industrial production index in France remained relatively stable in 2025 compared with the previous year (+0.5%)[18], with a positive trend at the end of the year, but the economic situation weighed particularly heavily on the sectors most represented among the major consumers, particularly chemicals (–3%). According to an economic analysis by INSEE, sluggish demand (order books) is the main reason why French industry suffered in 2025[19]. Some supply difficulties and a shortage of staff are still having an effect, though these are less significant than in 2023.

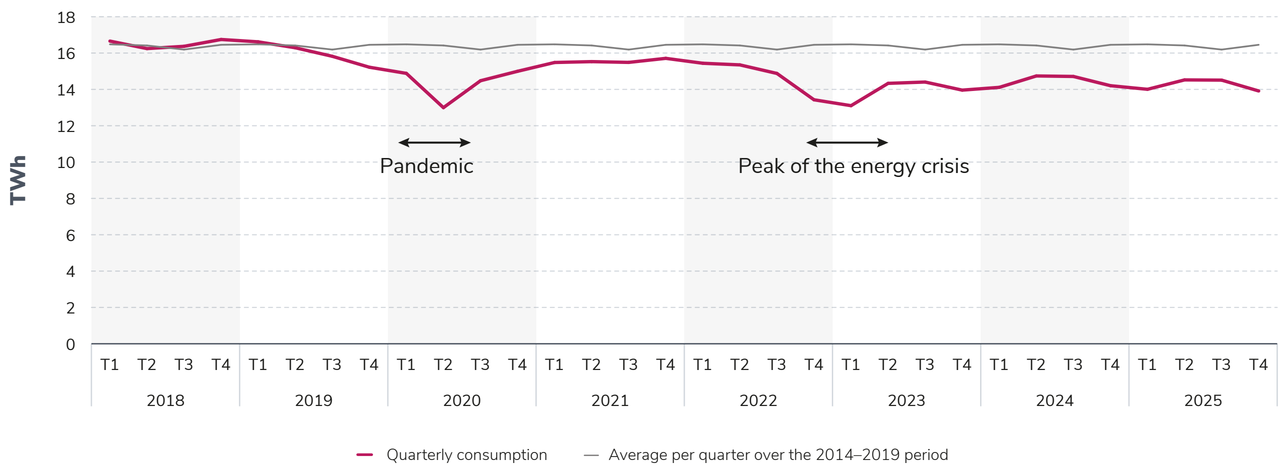
This fall is part of a long-term downward trend driven by energy efficiency improvements, successive crises (the 2008 economic crisis, the pandemic, the energy crisis) and the de-industrialisation that has been occurring since the 1990s, restructuring France's production base and tertiarising the economy. This trend seems to have halted in the mid-2010s with the beginnings of a move to re-industrialise, albeit subject to the geopolitical and commercial uncertainties of recent years[20], whose effects on electricity consumption are not yet visible.

17. Consumption among industrial users connected to the gas transmission networks also fell, but to a greater extent (–7%) – NaTran, 2025 Overview, January 2026
18. Calculation based on the INSEE industrial production index for 2025 compared with 2024.
Source: INSEE, *In December 2025, manufacturing output fell back sharply (–0.8%) – Informations rapides* No. 33, February 2026
19. DGT, *Flash conjoncture France – La demande a été le principal frein à la production industrielle en 2025*, November 2025
20. DGE, *Où en est la réindustrialisation de la France ?*, May 2024

The drop in demand for electricity in 2025 interrupted the recovery that began the previous year. Consumption by major consumers in 2024 was 3.2% higher than in 2023, thanks to a one-off rebound in activity after the peak of the energy crisis. However, this recovery was not as strong as the one that took place in 2021 after the pandemic, and did not return the sector to pre-crisis levels. In particular, the adaptations companies have made to keep their businesses going under difficult conditions (scaling back or reorganising activities, developing energy efficiency)[21,22] have led to a restructuring of the French industrial fabric[23,24]. In addition, even though market offers represent a larger proportion of supply contracts for professional consumers, enabling electricity price reductions to be passed on, some industrial consumers may still be dependent on contracts negotiated in previous years with much higher price levels.

**As a result, demand from major consumers connected to the PTS remained 13% lower in 2025 than in the pre-crisis period (2014–2019).** It is interesting to note that activity in the industrial sector had already begun to slow in 2019 due to rising trade tensions between the US and China on one hand and the US and the EU on the other. The Brexit negotiations also contributed to raising the level of uncertainty around investment and consumption.

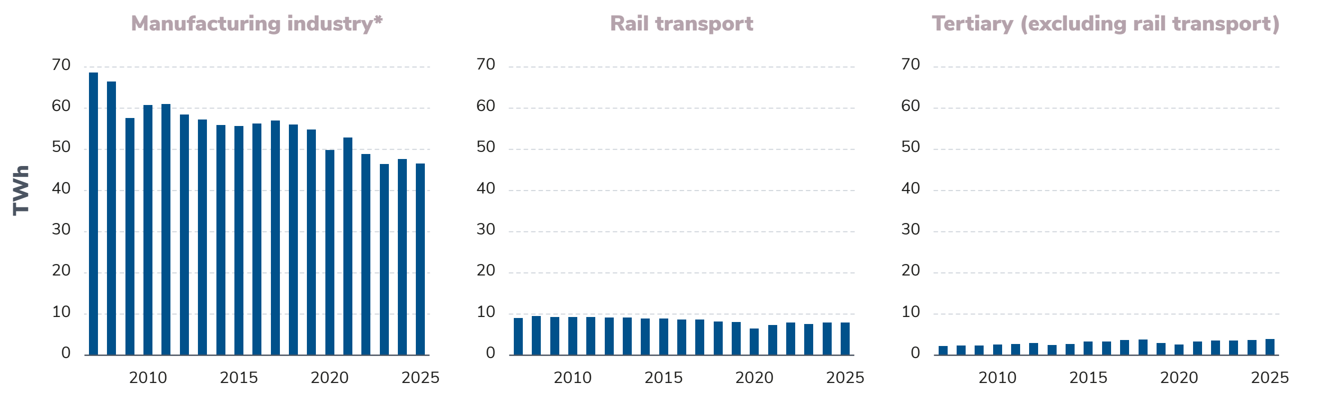
**Figure 1.9 – Quarterly consumption by major electricity consumers connected to the public transmission system between 2018 and 2025 (excluding the energy sector)**




21. INSEE, *Impact de la hausse des prix de l'énergie en 2022 sur l'activité des entreprises et leur consommation d'énergie – Les entreprises en France*, December 2023
22. INSEE, *Focus – Faced with energy price rises, companies are reacting mainly by increasing their selling prices, while also considering investments to reduce their energy bill – Growth is holding up, inflation too*, March 2023
23. Companies have been created at a faster rate than de-registrations, a sign that production factors are being reallocated. – DGE, *Comment expliquer l'augmentation des faillites d'entreprises ?*, February 2025
24. DGT, *Publication du rapport annuel 2023-2024 du Comité Interministériel de Restructuration Industrielle (CIRI)*, January 2026

Among major consumers, the decline was driven by manufacturing industry (–2.3%), while consumption in the rail transport and energy sectors remained stable. Electricity consumption by major consumers in manufacturing industry thus fell in 2025, after rising by almost 3% the previous year as the energy crisis drew to a close.

**Figure 1.10 – Electricity consumption by consumers connected to the public transmission system**

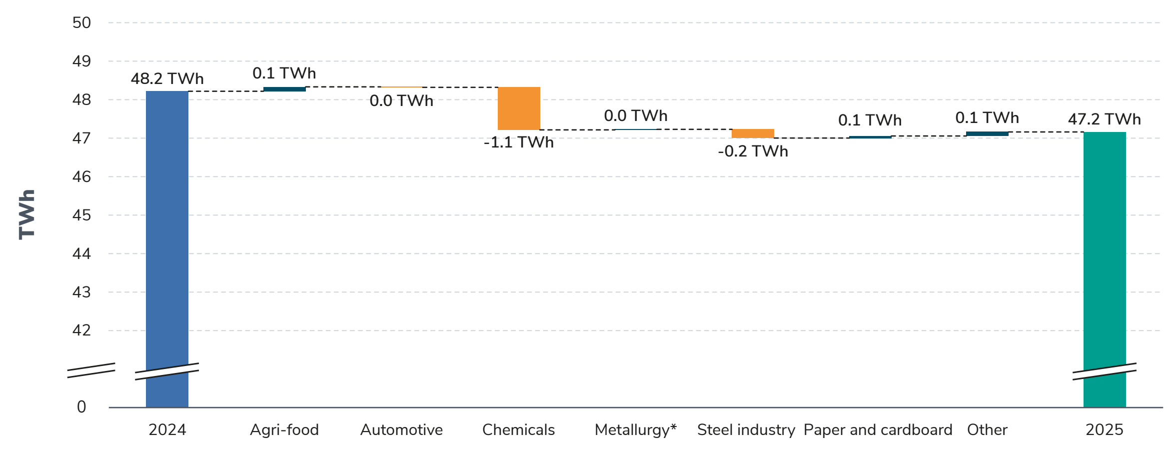



* Excluding uranium enrichment

**Within manufacturing, the biggest decline was in the chemicals industry (–9.2%), followed to a lesser extent by steel (–2.6%).**

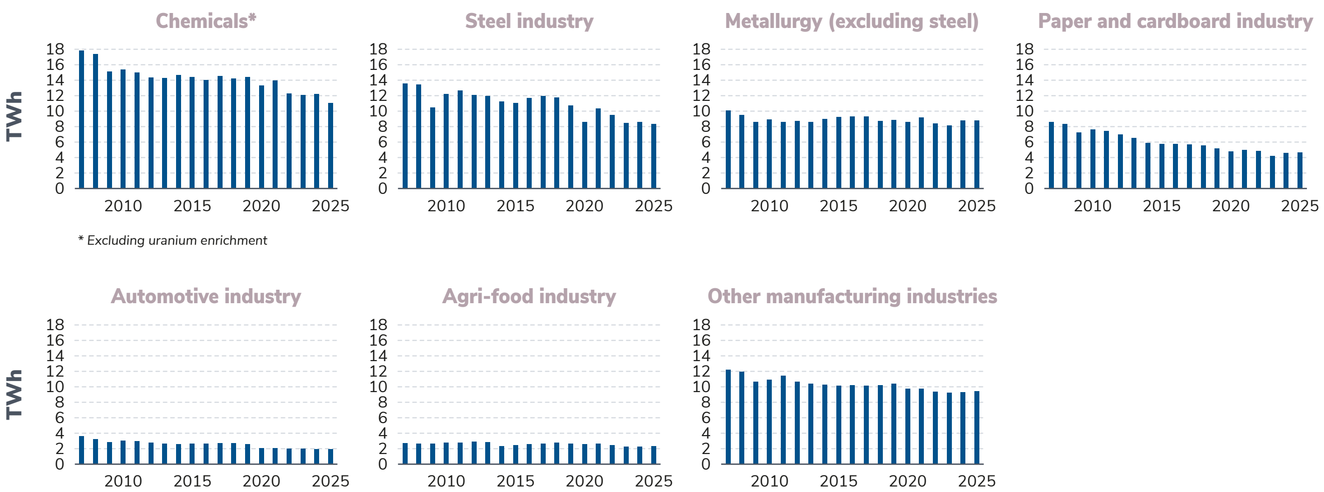
Trends for major consumers in these sectors (i.e. those connected to the electricity transmission network) are generally representative of national consumption as a whole, since a large proportion

**Figure 1.11 – Changes in consumption by major manufacturing consumers connected to the public transmission system between 2024 and 2025, by sector**




* Excluding steel

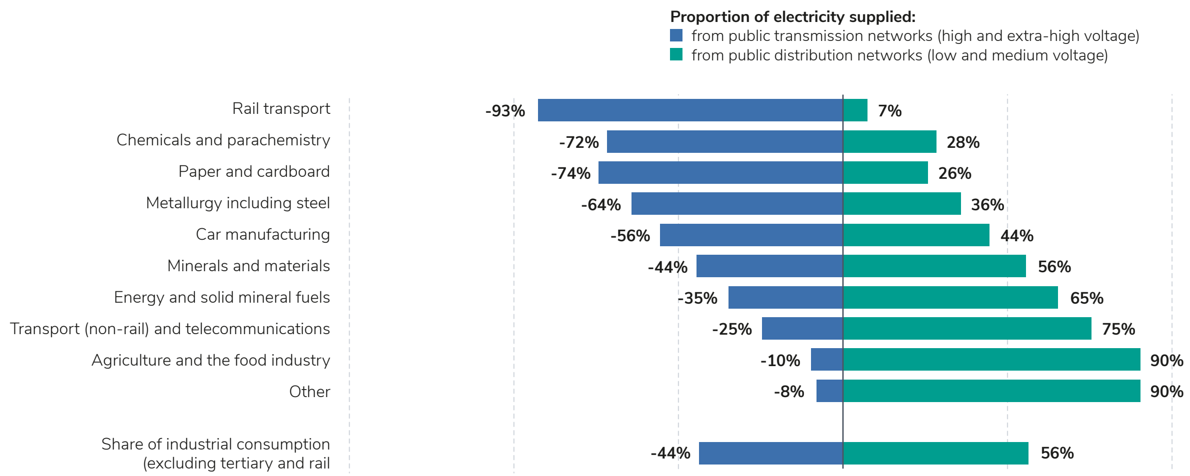
**Figure 1.12 – Electricity consumption by manufacturing industry connected to the public transmission system**




of consumption in these sectors is supplied directly by the public transmission system without passing through the distribution networks (with the exception of the agri-food sector). Overall, half of electricity consumption by manufacturing industry takes place via the transmission system.

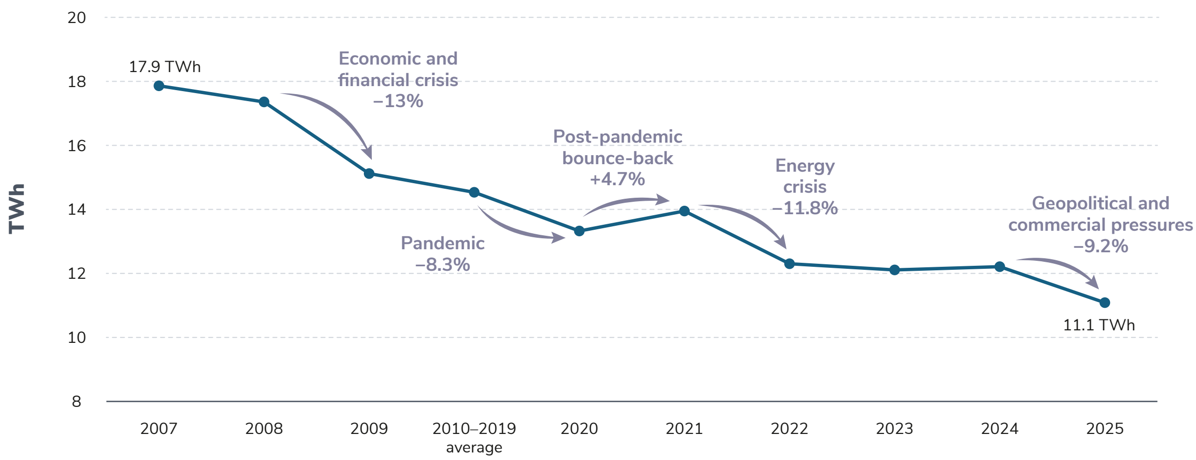
In Europe, the chemical sector has been experiencing difficulties for years due to a weak domestic market, a lack of global competitiveness resulting from higher energy costs than in the United States, Asia or the Middle East, and a lack of innovation. The gas used by the sector, for example, costs three times more in Europe than in the United States, and the introduction of tariffs by the US has made the situation even worse, as the sector is largely driven by exports[25]. According to INSEE[26], production in 2025 was 12% lower than in 2019. Faced with these difficulties,

**Figure 1.13 – Proportions of electricity consumption by French industry supplied from the transmission and distribution networks respectively in 2024 (segmented according to NAF REV2)**




25. Le Figaro, *Demande plus faible, concurrence chinoise, manque de compétitivité… En détresse, la chimie presse Bruxelles d'agir plus vite*, December 2025
26. INSEE, *Industrial production index base 2021*, January 2026

**Figure 1.14 – Electricity consumption over time by chemical manufacturers connected to the public transmission system***




* *Excluding uranium enrichment*

the European Union published a plan on 8 July 2025, aiming to strengthen the European chemical industry by enabling it to modernise and improve its competitiveness.

The steel industry is also facing a highly competitive environment and excess global production capacity. As with chemicals, the sector is also suffering from a decline in competitiveness, despite a trade protection mechanism put in place in 2018 (initially temporary, then made permanent in 2019[27]) to defend European steel. This will be replaced by a new system, announced on 8 October 2025[28], which is likely to be more effective.

27. Commission Implementing Regulation (EU) 2019/159 of 31 January 2019 imposing definitive safeguard measures against imports of certain steel products
28. Ministère de l'Économie des Finances et de la Souveraineté industrielle et énergétique, *Sidérurgie : la Commission européenne propose un mécanisme de protection contre les importations déloyales*, October 2025

# Data centre consumption is growing steadily but currently remains limited in comparison with other sectors

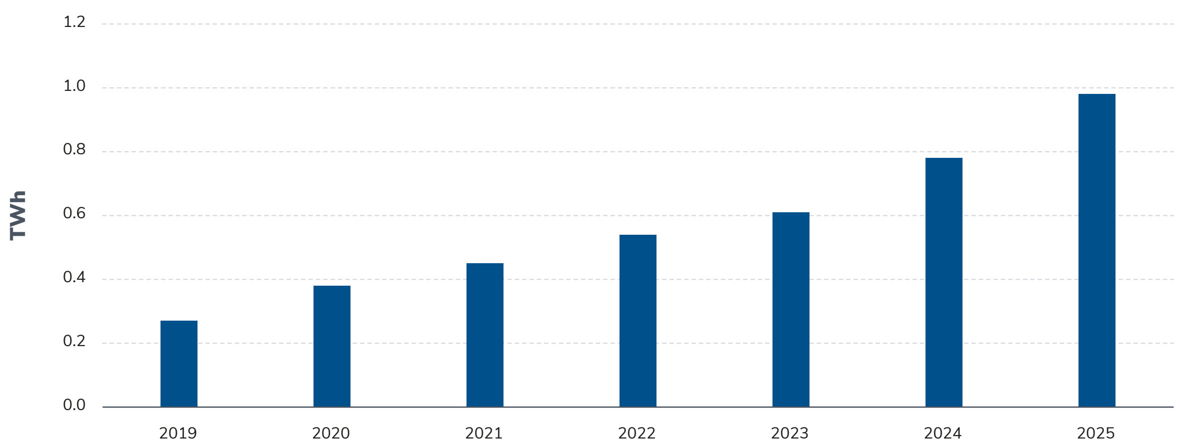
France has a favourable environment for the installation of digital infrastructure such as data centres, with its high-quality grid, abundant low-carbon electricity and industrial zones that are well connected to the major telecommunications networks.

Data centres are not all alike. Specifically, there is an important distinction between data centres on dedicated sites and data centres that are integrated into the premises of the company or public authority that uses them, where it is difficult to isolate data centre consumption from the rest of the company or public authority's consumption.

Electricity consumption by "dedicated site" data centres connected to the public electricity transmission system is currently relatively low compared with total French consumption: it reached almost 1 TWh in 2025 and around 0.8 TWh in 2024[29] (3 TWh on the Enedis public distribution system in 2024[30]). However, the trend is upwards for the moment, despite the energy efficiency improvements of recent years. This dynamic is partly due to the increase in needs linked to digital technology, such as storage, processing and security for fast-growing volumes of data, and artificial intelligence. As a result, the electricity consumption of these data centres has doubled in the four years between 2021 and 2025. This momentum could continue, given the major investments announced at the Artificial Intelligence Action Summit in February 2025 and the Choose France event in November 2025.

Today, the connection capacities of these centres vary from 40 to 240 MW, totalling 770 MW at the end of December 2025. They are mainly located

**Figure 1.15 – Electricity consumption by "dedicated site" data centres connected to the public transmission system**




29. Total consumption by data centres in France amounted to around 4 to 6 TWh in 2023, according to an estimate by the ministry: SDES, *La consommation d'électricité des centres de données entre 2018 et 2023*, October 2025
30. The 2025 figures were not yet available at the time of writing

in the Île-de-France region. The consumption of a new data centre tends to ramp up slowly before reaching its nominal operating power level, which may be lower than the connection capacity initially requested. This ramp-up period is generally long, with a significant difference between the power used and the connection capacity, even after several years of operation. The average rate at which connection capacity is used for facilities connected to the public transmission system is currently 22%.

## The residual load profile is continuing to stretch

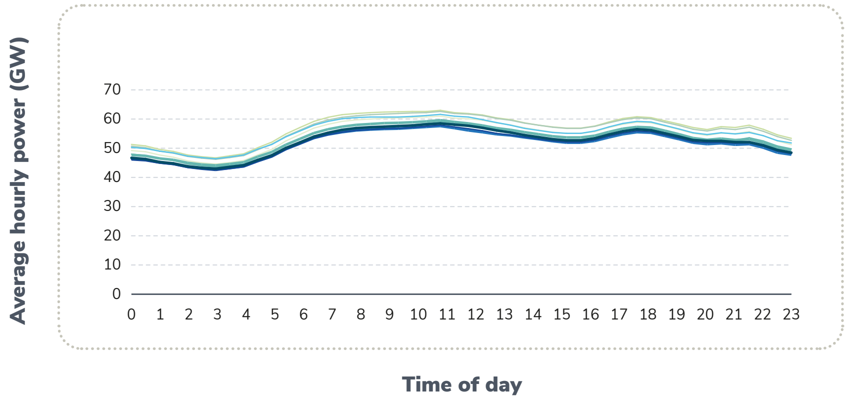
The operation of the power system requires a constant balance between electricity generation and consumption. This balance is ensured partly by the flexibility offered by dispatchable generation sources, including hydropower, thermal and nuclear, but also by the contributions of flexibility in consumption and in renewable generation (downward flexibility), which are also tending to develop.

The residual load curve is an indicator that can be used to analyse the system's flexibility needs. It corresponds to the consumption that remains to be met by dispatchable generation resources once the volumes of non-dispatchable renewable generation, with zero variable cost, have been taken into account. Over the last few years, the daily profile of residual load has changed significantly as a result of the drop in consumption levels and the development of renewable generation (particularly solar and wind). Its average level has gradually fallen and its shape has been hollowed out in the middle of the day due to the large volume of solar photovoltaic generation. The residual load curve is now characterised by two narrow peaks lasting a few hours (in the morning and evening) and two troughs (in the afternoon and at night).

This deformation illustrates the need to develop additional flexibility and the benefits it will provide for taking full advantage of plentiful low-carbon generation, particularly in the middle of the day. Adapting the consumption profile to the production profile, or “demand flexibility”, is one way of achieving this, and represents an important priority in managing an electricity mix with a high renewable proportion. This involves shifting consumption to times when low-cost, low-carbon generation (renewable and nuclear) is abundant, reducing consumption at times when these sources are less available.

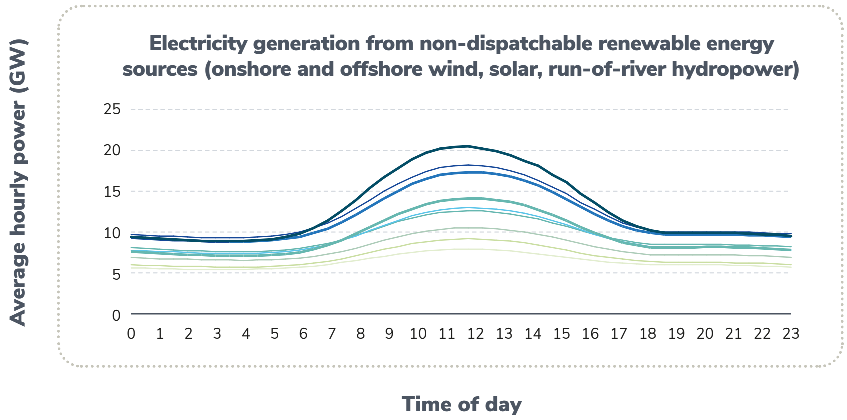
In addition, the development of generation flexibility, including the modulation of renewable output (participation in the balancing mechanism, controlled shutdowns during periods of negative prices, etc.), appears essential to ensure the power system can operate effectively during periods of plentiful generation (see the *Generation* chapter in the 2025 Electricity Review and the *Consumption* chapter in the 2025 Generation Adequacy Report).

Figure 1.16 – Gross consumption (not adjusted for weather effects)



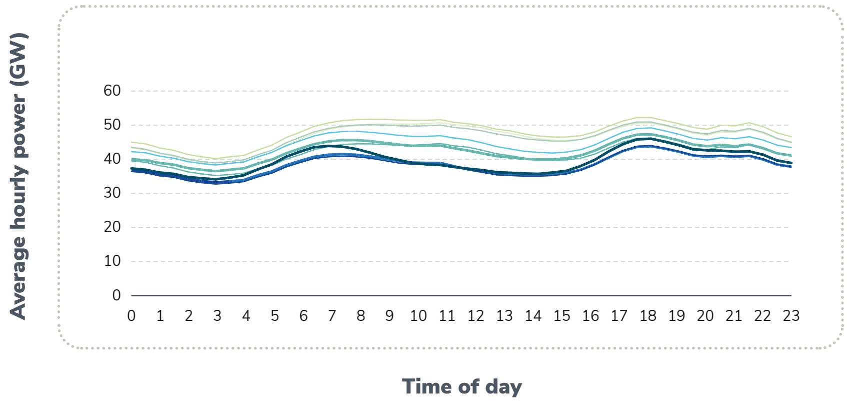

The gross consumption level (not adjusted for weather and calendar effects) remained low in 2025 compared with the pre-crisis years and close to the 2024 level.

Figure 1.17 – Electricity generation from non-dispatchable renewable energy sources (onshore and offshore wind, solar, run-of-river hydropower)




Renewable generation is increasing steadily as the installed capacity grows. Wind power is generated throughout the day, translating the curves upwards. Solar generation is concentrated around 1–2 pm, creating a "hump" in the middle of the day.

Figure 1.18 – Residual load to be covered by dispatchable resources




The residual load curve is shifting downwards under the combined effect of falling total consumption and rising wind generation. In the middle of the day, it is moving further down due to solar generation.

# Generation

**2025 ELECTRICITY REVIEW**

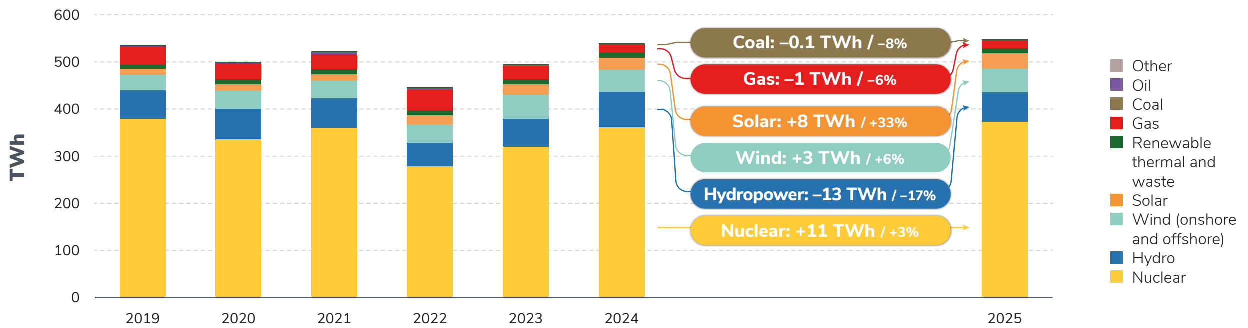
## Total electricity generation in France increased slightly in 2025, with the low-carbon proportion remaining at over 95%

Electricity generation in mainland France reached 547.5 TWh in 2025. After two years of strong growth in 2023 and 2024 of around 10% per year, due mainly to the renewed availability of the nuclear fleet and improved hydropower output resulting from more favourable weather conditions, the volume of electricity generated in mainland France grew very slightly in 2025 (+8.2 TWh, or +1.5% compared with the 2024 level).

This stability is the result of varying trends across the generation mix. In particular, 2025 was marked by a very significant drop in hydropower generation (–12.9 TWh), which had benefited from exceptional rainfall in 2024. This fall was offset by nuclear output, which returned to higher levels after the recovery that began in 2023 and continued in 2024 (+11.3 TWh higher in 2025 than in 2024), and by the increase in solar (+8.1 TWh) and wind (+2.8 TWh), driven particularly by capacity growth. Fossil-fired

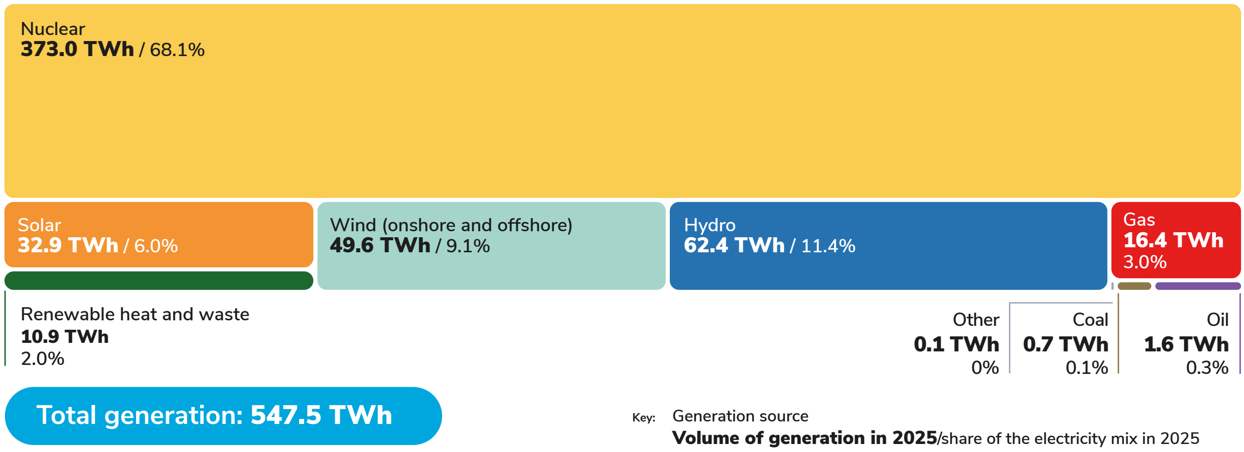
**Figure 2.1 – Annual electricity generation by energy source between 2019 and 2025**

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|
| Total generation (TWh) | 536.0 | 499.7 | 522.4 | 446.3 | 494.7 | 539.3 | 547.5 |
| Low-carbon proportion (%) | 91.0 | 91.2 | 91.4 | 87.4 | 92.4 | 95.0 | 95.2 |
| Renewable proportion (%) | 20.2 | 24.1 | 22.4 | 24.9 | 27.6 | 27.9 | 27.0 |




* Power generated from household waste is considered 50% renewable. Seventy percent of PSH pump consumption is deducted from hydropower generation in accordance with European Directive 2009/28/EC.

Figure 2.2 – Total electricity generation in France in 2025 and breakdown by source




generation fell for the third year running (–1.3 TWh) and remains, as in 2024, at a very low level, unseen since the early 1950s.

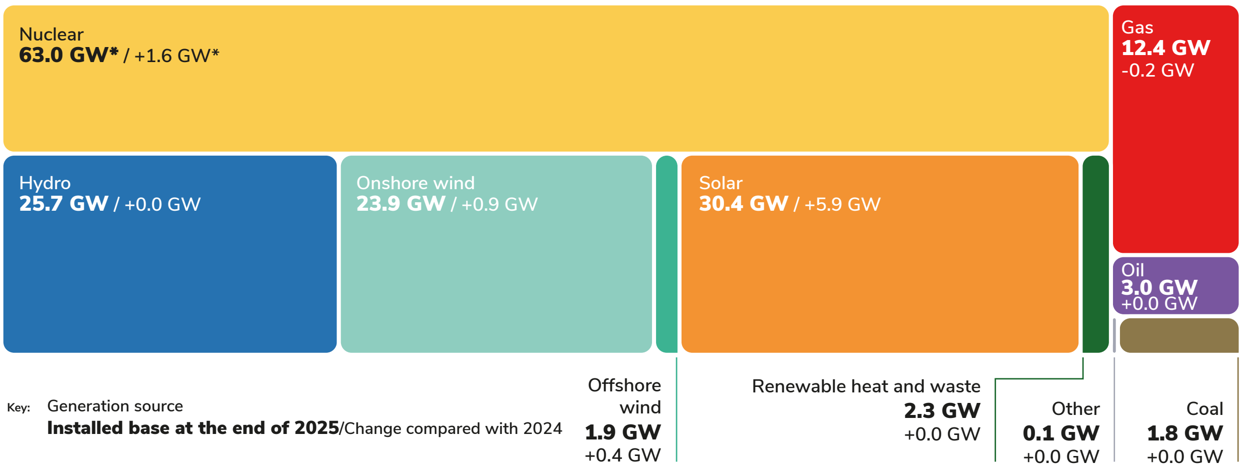
**The volume of low-carbon (nuclear and renewable) electricity generated in France reached an all-time high of 521.1 TWh in 2025. This represents 95.2% of the electricity generated in mainland France, a similar proportion to 2024 (95.0 %).** On the other hand, the proportion of electricity from renewable sources fell in 2025 (27%) following the historic level reached in 2024 (27.9%).

## France's electricity generation fleet continues to expand

The electricity generation fleet in mainland France is continuing its growth, with 8.7 GW of new capacity installed across the generation mix in 2025.

This expansion was driven primarily by solar capacity (+5.9 GW), which continued to grow at a high rate in 2025. It also reflects the nuclear fleet, with the Flamanville 3 nuclear reactor (1.6 GW) connected to the grid in December 2024 and commissioned gradually over the course of 2025 and early 2026. Onshore (+0.9 GW) and offshore wind capacity (+0.4 GW) also increased, though to a lesser extent. On the other hand, gas-fired electricity generation capacity fell slightly (–0.2 GW[1]), mainly due to closures of small cogeneration plants.

**Figure 2.3 – Electricity generation capacity in France at the end of 2025 and breakdown by source**




** Including Flamanville 3, which is currently being commissioned*

1. This includes cogeneration; see also footnote 30.

# Nuclear generation increased in 2025, returning to a level close to 2019, though with changes in reactors' output profiles

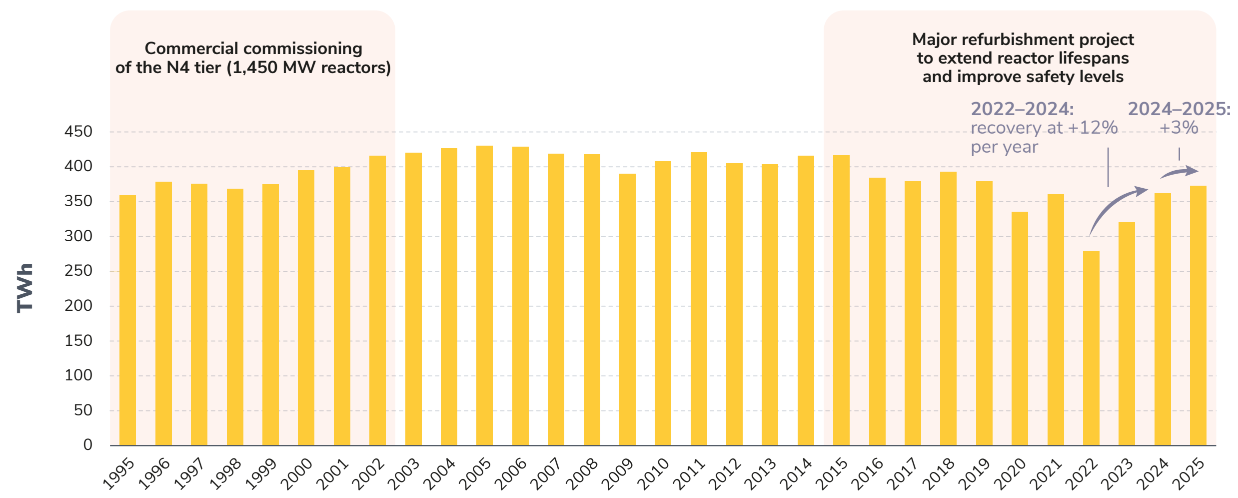
Total French nuclear generation rose for the third year running, after reaching a low point in 2022. It amounted to 373.0 TWh, 11.3 TWh more than in 2024 (+3%). However, this increase was much smaller than the ones observed between 2022 and 2023 (+23 TWh, or +11%) and between 2023 and 2024 (+30 TWh, or +13%). The sharp rise in output in 2023 and 2024 corresponded to the recovery from the stress corrosion crisis, whose effects began to be felt from the end of 2021 and became particularly noticeable in 2022. By 2024, annual output had almost returned to pre-crisis levels.

**The trend observed in 2025 thus confirms that the availability of France's nuclear fleet has returned to a level comparable to before the crisis.**

In 2022, at the height of the crisis, up to almost 65% of the fleet was shut down at the same time, due to the combined effect of stress corrosion-related maintenance and the impact of the pandemic on maintenance schedules. Given the high proportion of nuclear generation in the French electricity mix (between 63% and 77% over the last ten years, and 68.1% in 2025), the 2022 crisis had far-reaching consequences for the power system, including increased reliance on imports: France once again became a net importer of electricity for the first time since 1980. To a lesser extent, fossil-fired generation, mainly using gas, also increased, though at a limited rate.

The gradual completion of checks and repairs related to stress corrosion in 2023 and 2024 enabled output to gradually recover to a level in excess of 360 TWh by 2024. At the same time, France once again became a major exporter and fossil-fired generation fell to historically low levels.

Figure 2.4 – Nuclear power generation in France since 1995



**The year 2025 confirms the findings of 2024: the effects of stress corrosion and the repercussions of the pandemic on production have almost disappeared.** The risks and challenges associated with stress corrosion seem to be well understood and controlled by the operator. The reactor inspection strategy now allows this phenomenon to be monitored without having to carry out the major operations initially required for reactors suspected of being at risk of this type of defect.

The output achieved in 2025 (373.0 TWh) is slightly higher than the short-term projections set out in a number of recent publications. The Commission de régulation de l'énergie[2] (the French energy regulation commission) refers to a baseline level of 362 TWh/year between 2026 and 2028. In RTE's 2023 and 2025 Generation Adequacy Reports, the central level of generation is projected to be around 360–365 TWh/year between now and 2030. Finally, the operator anticipates a range of 350 to 370 Twh3[3] for 2026 and 2027.

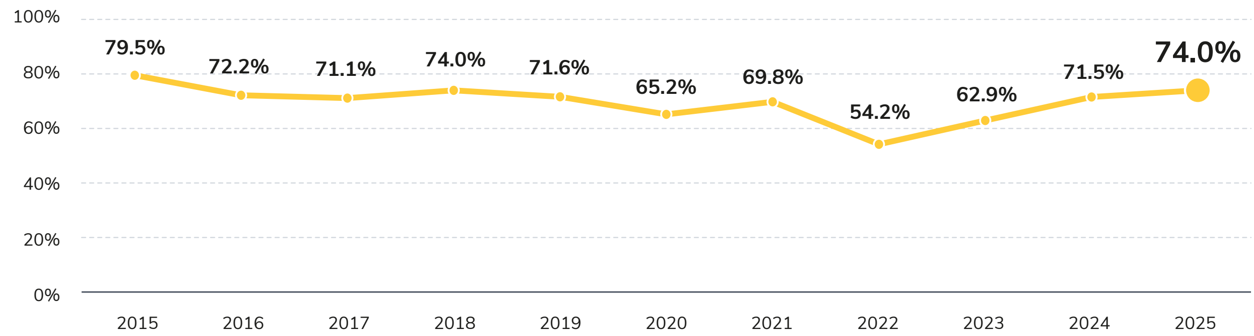
These projections are based on forecasting: the actual level of production that will be observed each year remains relatively uncertain, as it depends on a large number of factors associated with the power system as a whole (including weather conditions, unforeseen events affecting the availability of resources, etc.).

**The current strong performance of nuclear power compared with the predicted levels offers hope of a relatively favourable situation over the next few years (barring a new crisis), supporting an acceleration in the electrification and re-industrialisation of the country, which should lead to an increase in consumption in the medium term.**

## Good overall availability, thanks partly to a relatively low number of major maintenance operations

The trend observed in terms of generation, i.e. a slight improvement in 2025 after significant increases between 2022 and 2024, also applies to availability, which stood at 74.0%[4] for 2025 as a whole, a level two and a half points higher than the previous year (71.5%). Since 2024, the nuclear fleet has returned to levels of availability close to those seen in the years preceding the stress corrosion crisis.

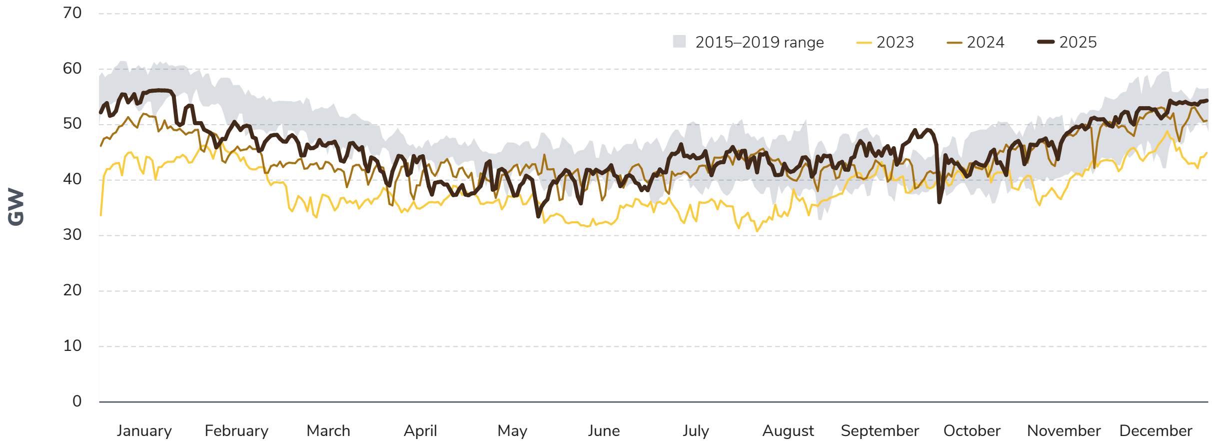
**Figure 2.5 – Annual availability rate* of the French nuclear fleet between 2015 and 2025**




* *Based on downtime declared under REMIT. The calculated rate is slightly lower than the availability coefficient (Kd) reported by EDF in its annual publications, because it includes all types of unavailability regardless of their causes. In its annual publications, EDF reports certain shutdowns (to save fuel, for example) and certain power limitations (to comply with temperature limits for cooling water discharged by the reactor, for example) as modulations rather than unavailability. We include all unavailability, whatever its origin, as it is not always possible to identify the precise cause. The calculation excludes the Flamanville EPR, which is still in the testing phase.*

2. In its September 2025 report assessing the full costs of nuclear power: CRE, Evaluation des coûts complets de production de l'électricité au moyen des centrales électronucléaires historiques pour la période 2026-2028, September 2025
3. EDF, press release: Estimated nuclear generation in France, 18 December 2025
4. Excluding the Flamanville EPR, which is currently in the testing phase.

**Figure 2.6 – Trend in average daily nuclear availability in 2025 and comparison with previous years**




Overall fleet availability was close to the bottom of the historical pre-crisis range[5] (2015–2019) in the first half of 2025 and broadly within the historical range from June onwards. Availability was relatively close to the 2024 level throughout the year, with the exception of January, February and March, when it was higher. This difference is due to the fact that a large number of ten-yearly inspections had been concentrated in these months during the previous year (see below).

Analysing the monthly availability rates for each power plant shows that most of them had very high availability in January and February, which are the most important months in terms of security of supply. The operator usually schedules work on the fleet so that shutdowns are concentrated as far as possible from spring to autumn, in order to maximise availability during the winter months.

**Figure 2.7 – Average monthly availability rate of each nuclear power plant in 2025**

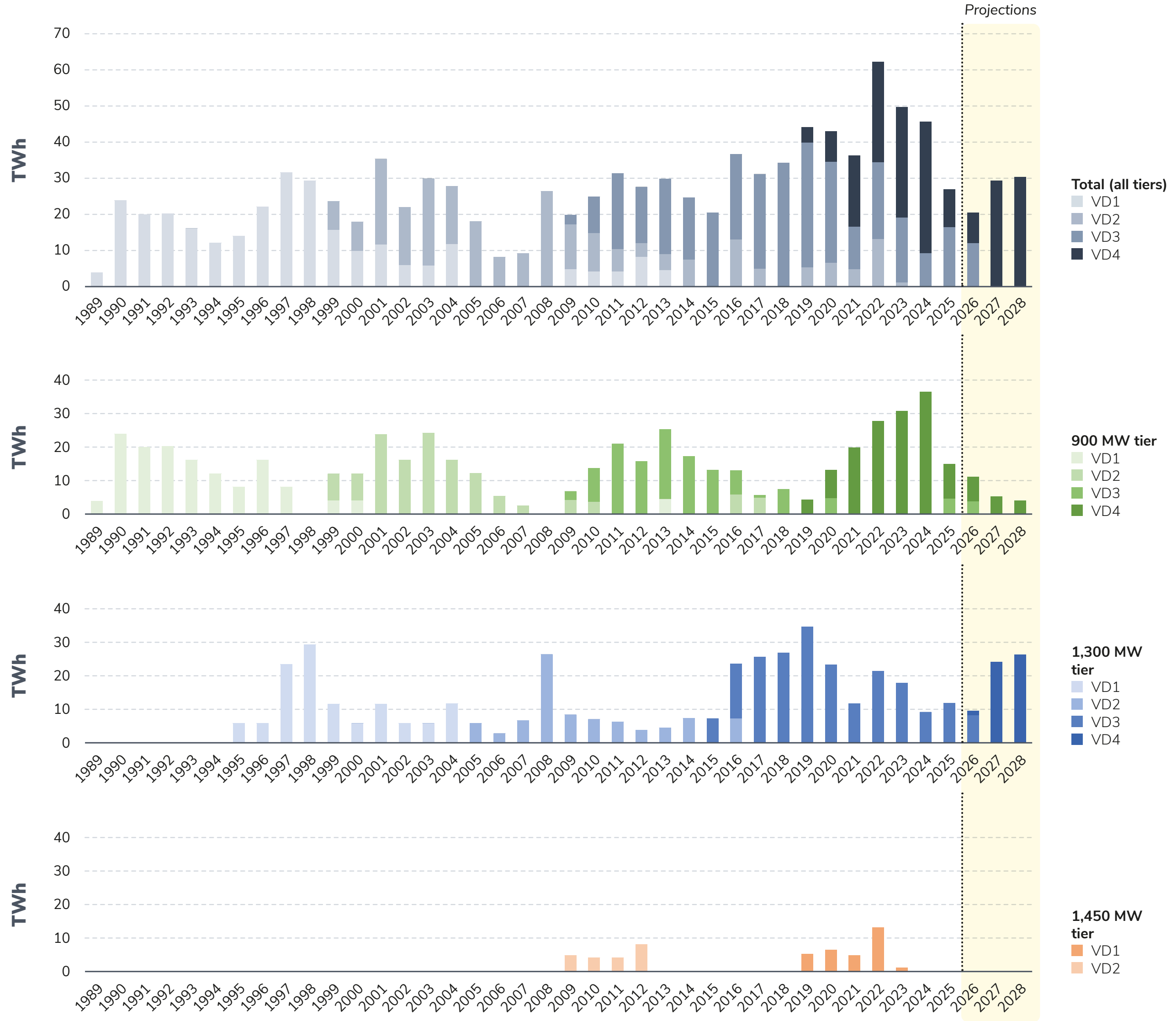
| Plant | No. of reactors | Tier | Installed power | 2025 Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Belleville | 2 | 1,300 | 2.6 GW | 99% | 99% | 100% | 66% | 61% | 86% | 31% | 60% | 50% | 40% | 0% | 43% | 61% |
| Blayais | 4 | 900 | 3.6 GW | 97% | 79% | 83% | 76% | 52% | 61% | 70% | 61% | 70% | 76% | 92% | 94% | 76% |
| Bugey | 4 | 900 | 3.6 GW | 95% | 88% | 72% | 61% | 77% | 88% | 93% | 76% | 50% | 49% | 73% | 96% | 76% |
| Cattenom | 4 | 1,300 | 5.2 GW | 99% | 87% | 82% | 60% | 46% | 45% | 70% | 72% | 96% | 91% | 98% | 96% | 79% |
| Chinon | 4 | 900 | 3.6 GW | 99% | 75% | 73% | 70% | 70% | 86% | 74% | 74% | 61% | 69% | 99% | 100% | 79% |
| Chooz | 2 | 1,450 | 2.9 GW | 97% | 91% | 93% | 66% | 46% | 49% | 78% | 79% | 49% | 40% | 41% | 51% | 65% |
| Civaux | 2 | 1,450 | 2.9 GW | 85% | 100% | 97% | 54% | 49% | 49% | 62% | 99% | 100% | 54% | 82% | 100% | 78% |
| Cruas | 4 | 900 | 3.6 GW | 73% | 50% | 63% | 70% | 83% | 78% | 42% | 59% | 73% | 65% | 75% | 82% | 68% |
| Dampierre | 4 | 900 | 3.6 GW | 100% | 88% | 76% | 67% | 71% | 63% | 73% | 75% | 71% | 72% | 76% | 99% | 78% |
| Flamanville* | 2 | 1,300 | 2.6 GW | 42% | 50% | 50% | 49% | 82% | 68% | 84% | 94% | 95% | 88% | 50% | 49% | 67% |
| Golfech | 2 | 1,300 | 2.6 GW | 95% | 62% | 47% | 53% | 46% | 48% | 37% | 46% | 50% | 46% | 50% | 50% | 52% |
| Gravelines | 6 | 900 | 5.4 GW | 91% | 79% | 63% | 66% | 56% | 66% | 86% | 49% | 66% | 64% | 77% | 83% | 70% |
| Nogent | 2 | 1,300 | 2.6 GW | 100% | 82% | 97% | 70% | 49% | 50% | 83% | 91% | 99% | 78% | 100% | 100% | 83% |
| Paluel | 4 | 1,300 | 5.2 GW | 74% | 88% | 78% | 74% | 74% | 74% | 93% | 75% | 76% | 100% | 95% | 96% | 83% |
| Penly | 2 | 1,300 | 2.6 GW | 47% | 50% | 50% | 59% | 76% | 89% | 90% | 85% | 97% | 97% | 98% | 97% | 78% |
| Saint-Alban | 2 | 1,300 | 2.6 GW | 100% | 100% | 90% | 87% | 83% | 50% | 50% | 49% | 51% | 92% | 98% | 100% | 79% |
| Saint-Laurent | 2 | 900 | 1.8 GW | 100% | 50% | 49% | 47% | 46% | 39% | 41% | 69% | 92% | 52% | 99% | 99% | 65% |
| Tricastin | 4 | 900 | 3.6 GW | 91% | 75% | 75% | 89% | 68% | 78% | 75% | 62% | 92% | 72% | 76% | 88% | 78% |

** Excluding Flamanville 3 EPR.*

5. The installed capacity was then 1.8 GW higher, with the two reactors at the Fessenheim plant still in operation at the time (until February 2020 for one and June 2020 for the other).

Major maintenance, and particularly ten-yearly inspection programmes, had a relatively limited effect in 2025. Energy not produced due to ten-yearly inspections in 2025 was the lowest observed since 2016 (around 27 TWh compared with an average of 43 TWh between 2016 and 2024). This significant reduction is the result of several factors: the end of the fourth ten-yearly inspection cycle for 900 MW reactors, which was particularly busy because it corresponded to the period in the early 1980s when the most reactors were commissioned[6]; the operator's gradual implementation of a programme to improve control of reactor outages[7] between 2020 and 2025; and finally the resolution of the availability problems arising from the stress corrosion crisis, which had led to the duration of certain ten-yearly inspection

**Figure 2.8 – Energy not generated by the French nuclear fleet due to ten-yearly inspections between 1989 and 2025, and projections for 2026–2028**




**Details of the calculation method:** RTE estimates the energy not generated based on:
- the dates of the ten-yearly inspections (sources: Cour des Comptes for the years up to 2004, ASNR for the years 2005–2025, REMIT declarations for the years 2026 to 2028);
- and the durations of the ten-yearly inspections (sources: normative duration estimated at four months for the years up to 2004, ASNR for the years 2005–2025, REMIT declarations for the years 2026 to 2028).

6. This level of concentration specific to ten-yearly inspections of 900 MW reactors can also be observed, necessarily, in the first half of each of the previous decades (see Figure 6).
7. Called START 2025, its aim is to limit accidental overruns of the shutdown schedule, thereby maximising available generation.

programmes being extended to carry out corrosion-specific checks that were not initially planned.

From this point of view, 2025 and 2026 are the exceptions (according to the planned timetable). The ten-yearly inspection schedule is set to intensify again thereafter. The fourth programme of ten-yearly inspections for reactors in the 1,300 MW class, designed to extend their operation to 50 years, will start in 2026. This cycle, which affects a large number of reactors and should extend their lifetime beyond the initial duration, presents major challenges from an industrial viewpoint. From 2029 onwards, the fifth cycle of ten-yearly inspections for the 900 MW reactors will also begin, bringing further major industrial challenges and a tight schedule.

**Availability profiles vary considerably over time and from one plant to another.**

Over the last decade, the plants that make up France's nuclear fleet have had widely differing availability rates. For a given power plant, availability varies considerably over the period depending on the life of its reactors, including major outages such as the ten-yearly inspections but also the hazards affecting their operation and maintenance.

Over the period as a whole, overall availability also varies from one plant to another. For example, the two power plants where the stress corrosion phenomenon was first identified, and which were the most affected by the episode, can be clearly identified: the four reactors at the Chooz and Civaux power plants, all belonging to the 1,450 MW range, were shut down for the whole of 2022.

On the other hand, some plants have high availability rates of over 80% in certain years: these are years in which no major maintenance was planned on any of the reactors at these plants. Such years were few and far between over the past decade due to the sustained programme of long-term maintenance, and particularly the *Grand Carénage* major refit programme (see figure 2.8). Apart from years that are exceptional for one reason or another, the causes underlying a power plant's availability level are very varied, and often specific (see below).

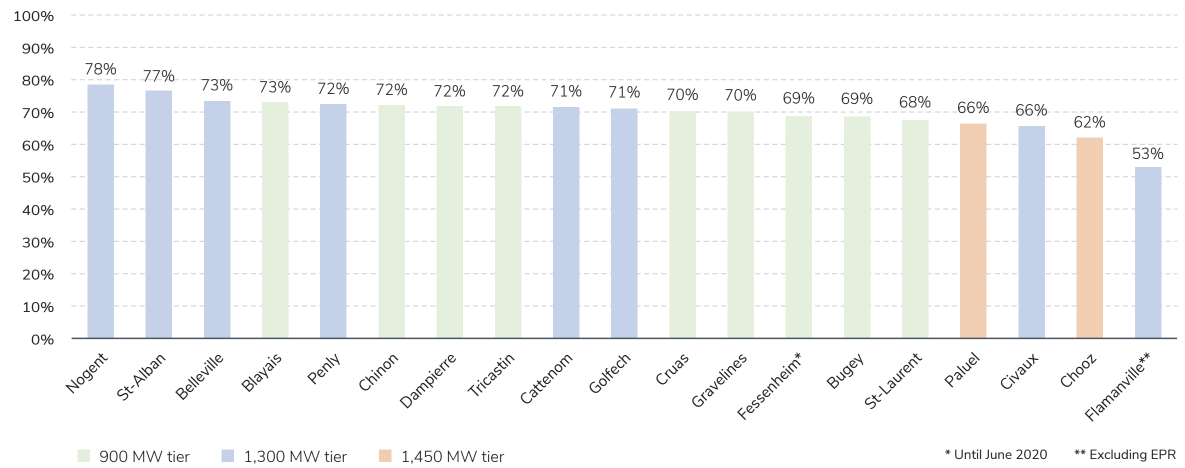
The overall availability of the majority of power stations over the decade from 2015 to 2025 was in the 60–75% range. Apart from generic maintenance (i.e. maintenance that applies in principle to all reactors, with a schedule defined by the authorities), the availability of each reactor is different and depends on

**Figure 2.9 – Average availability rate of each nuclear power plant per year over the decade 2015–2025**

| | 2015–2025 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Plant** | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2015–2025 |
| Belleville | 91% | 74% | 65% | 76% | 66% | 69% | 82% | 73% | 60% | 92% | 61% | 73% |
| Blayais | 64% | 77% | 83% | 84% | 80% | 74% | 77% | 71% | 58% | 60% | 76% | 73% |
| Bugey | 83% | 48% | 78% | 78% | 85% | 49% | 66% | 53% | 80% | 60% | 76% | 69% |
| Cattenom | 84% | 73% | 84% | 71% | 72% | 74% | 68% | 44% | 63% | 71% | 79% | 71% |
| Chinon | 77% | 75% | 78% | 80% | 75% | 65% | 74% | 64% | 57% | 66% | 79% | 72% |
| Chooz | 82% | 90% | 62% | 84% | 71% | 52% | 53% | 0% | 63% | 61% | 65% | 62% |
| Civaux | 83% | 71% | 73% | 76% | 88% | 58% | 48% | 0% | 77% | 80% | 78% | 66% |
| Cruas | 70% | 72% | 74% | 71% | 70% | 69% | 71% | 65% | 67% | 74% | 68% | 70% |
| Dampierre | 83% | 78% | 79% | 71% | 77% | 64% | 64% | 60% | 74% | 69% | 78% | 72% |
| Flamanville* | 71% | 88% | 61% | 55% | 29% | 2% | 75% | 19% | 52% | 62% | 67% | 53% |
| Golfech | 91% | 94% | 81% | 81% | 82% | 78% | 67% | 55% | 23% | 81% | 52% | 71% |
| Gravelines | 81% | 67% | 67% | 74% | 69% | 70% | 64% | 60% | 62% | 71% | 70% | 69% |
| Nogent | 71% | 93% | 85% | 74% | 72% | 73% | 83% | 83% | 62% | 86% | 83% | 79% |
| Paluel | 70% | 44% | 48% | 71% | 60% | 59% | 68% | 75% | 74% | 71% | 83% | 66% |
| Penly | 93% | 81% | 84% | 79% | 75% | 76% | 80% | 30% | 48% | 70% | 78% | 72% |
| Saint-Alban | 84% | 81% | 66% | 60% | 83% | 81% | 85% | 72% | 70% | 82% | 79% | 77% |
| Saint-Laurent | 69% | 79% | 79% | 77% | 69% | 77% | 58% | 61% | 35% | 73% | 65% | 68% |
| Tricastin | 85% | 65% | 63% | 68% | 65% | 76% | 75% | 68% | 75% | 73% | 78% | 72% |

* *Excluding Flamanville 3 EPR.*

**Figure 2.10 – Ranking of French nuclear power plants by average availability over the decade 2015–2025**




specific events and hazards. Nevertheless, the following observations can be made:

- the four reactors in the 1,450 MW range, the most recent apart from the EPR, have a significantly lower rate than the average: this is because this was the range most affected by the stress corrosion phenomenon;
- the 1,300 MW plants all performed better than average, with the exception of the Paluel and Flamanville plants, which were faced with special circumstances[8].

## The operating conditions of France's nuclear fleet are unique

The nuclear share of France's electricity mix is an important factor in the operation of its reactors and the power system as a whole.

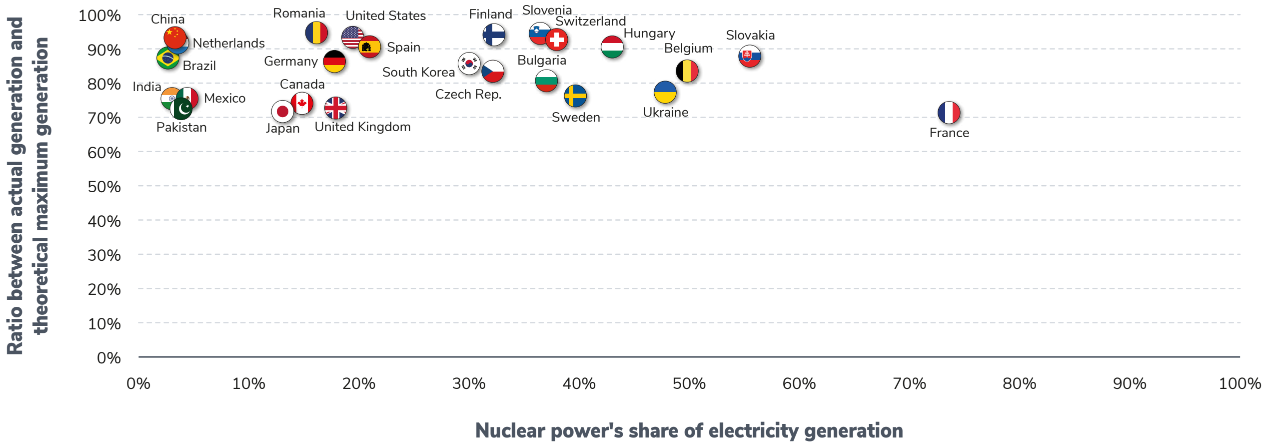
In most countries with nuclear power, the plants were built to operate as baseload generation. In France, given the importance of nuclear as a share of the electricity mix, the reactors were designed from the outset to modulate their electricity generation when in operation and thus adapt to variations in electricity consumption, both between seasons and on a daily or weekly basis. With the massive development of the nuclear fleet from the late 1970s onwards, the country could call on abundant electricity generation, making it possible to plan for a reduction in dependence on fossil fuels: as a result, electric heating was encouraged more than in other countries, leading to significant variations in consumption between winter and summer. Furthermore, the nuclear fleet has historically adapted to the fact that consumption is generally lower at night and at weekends.

In addition, given the large number of reactors in service, it is extremely unlikely that the entire nuclear fleet will be available at the same time, due to the industrial constraints on maintenance schedules, which mean that maintenance shutdowns are spread out over the year. As a result, French nuclear generation almost never reaches its maximum installed capacity. In other countries, with much smaller numbers of reactors, the fleet produces at maximum capacity almost every year, for varying lengths of time.

The reasons that may cause the nuclear fleet to be unavailable differ widely. As an outline, starting from the maximum annual energy that can theoretically be

8. Reactor number 2 at Paluel was shut down for almost three whole years due to an unusual technical incident during its ten-yearly inspection, while reactors 1 and 2 at the Flamanville power station encountered specific difficulties due partly to maintenance on the emergency generators, which led to prolonged shutdowns.

**Figure 2.11 – Ratio of the nuclear fleet's actual output to the theoretical maximum output in selected countries over the period 2000–2024**




**RTE calculation based on the following data:**

**For theoretical maximum output data:** reconstruction based on commissioning dates and installed power data from the International Atomic Energy Agency's *Power Reactor Information System.*

**For actual output data:** European Union member states: *Eurostat*; Switzerland: *Federal Office of Energy*; United Kingdom: *Digest of UK Energy Statistics*; Brazil: *Empresa des Pesquisa Energética*; Mexico: *Comisión Federal de Electricidad*;

For some countries, the official data available only covers part of the period.

China: 2000–2023 / *National Bureau of Statistics of China*; South Korea: 2000–2023 / *Korea Energy Statistical Information System*; India: 2016–2024 / *NITI Aayog*; Pakistan: 2001–2020 / *Pakistan Bureau of Statistics*; Canada: 2009–2024 / *Statistics Canada*;

For Ukraine and Japan, the period analysed is as follows:
Ukraine: 2000–2020 (Russian invasion of the country in 2022) / *Eurostat*; Japan: 2000–2010 (most reactors shut down following the Fukushima accident in 2011) / *Agency for Natural Resources and Energy*

generated, i.e. the energy that would be generated if the whole fleet operated without interruption at its rated power level and under reference weather conditions[9], a number of effects of very different kinds limit the actual generation level of the fleet:

1) **Lower production due to the seasonal variability of the reactors' maximum effective power,** which depends partly on the temperature of the cooling source. As this can vary from the reference conditions at which the reactors' rated power is calculated, these deviations tend to slightly reduce the maximum energy that can be generated over the year.

2) **Planned or unplanned outages.** These include ten-yearly inspections ("VD", usually lasting around six months), partial or periodic inspections ("VP"), outages for refuelling (about every 12 to 18 months, usually lasting one month) and outages for routine maintenance or testing. Outages may also occur due to technical faults in a reactor, industrial action or environmental constraints such as the temperature of the cooling source being too high, particularly in the case of power stations located along rivers. For a given reactor, the operator generally alternates between partial outages and shutdowns for refuelling only. Ten-yearly inspection programmes are explicitly required by

9. The rated capacity of a reactor, which is a single value, is determined for specific meteorological conditions, including the conditions that affect the cooling source enabling the core to be cooled. In practice, actual conditions deviate from these reference conditions most of the time: this is one of the main reasons for the seasonal variability in the effective maximum power of the fleet.

law, while the frequency of refuelling outages is dictated by the fuel cycle. The exact schedule for partial inspections is determined on a case-by-case basis by the operator, working with the safety authorities. These periods of unavailability correspond to operations that may be complex and are often combined; in addition, although these are scheduled operations, unplanned schedule overruns can occur. As a result, the actual duration of this category of shutdowns may differ from the standard durations. Given the repercussions for the performance of the fleet, the operator takes particular care to control these longer shutdowns[10].

3) **Energy not generated due to modulation: this may involve reactors contributing to balancing the system, modulation due to a lack of economic outlets or modulation for fleet management purposes.** These modulations can take the form of *shutdowns* varying in length (over a weekend, for example), or power reductions with the reactor still running. An example of modulation for fleet management purposes is modulation to *save fuel*, which depends on the schedule of refuelling outages for the reactor concerned and overall fleet scheduling. As the refuelling interval is limited (between 12 and 18 months), if a reactor is subject to heavy demand and/or if the next outage is scheduled a little later than usual (typically to wait for the end of winter), it may at some point become necessary to save a certain amount of fuel to “hold out” until the next refuelling[11]. France's nuclear fleet was designed from the outset to incorporate a degree of modulation into its operation.

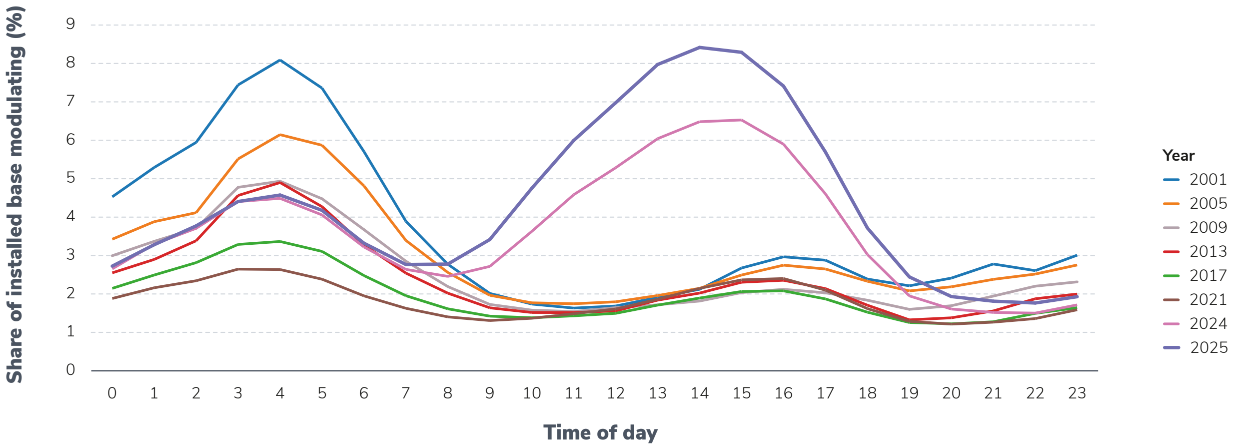
In 2025, outages for refuelling and routine maintenance (whether combined or not) remained by far the leading cause of energy not generated (compared with the theoretical maximum volume), with a total impact of around 80 TWh (approximately 50 TWh for partial inspections and 30 TWh for outages for refuelling). These operations occur frequently and in large numbers, which allows for a degree of expansion and explains the relative stability over time – apart from exceptional situations such as the pandemic or stress corrosion. As far as the ten-yearly inspection programmes are concerned, 2025 was characterised by a relatively light schedule. Eleven reactors had undergone a ten-yearly inspection at one time or another in 2024. At the beginning of February 2024, eight reactors were shut down *simultaneously* for ten-yearly inspections, which is quite exceptional: this was made possible partly by a comfortable situation in terms of security of supply. In 2025, only six reactors were shut down for this reason. In total, it is estimated that the energy that could not be generated due to ten-yearly inspections in 2025 was much lower than in 2024 (27 TWh compared with 46 TWh), which contributed to the high availability levels recorded.

Modulation (across all types) represented around 30 TWh in 2025, a relatively stable volume compared with the previous year. This is not a new phenomenon. For example, comparable or even higher levels were reached in the 1990s and early 2000s, in a context where generation capacity exceeded consumption. Over the last few years, while the volumes have been comparable, the modulation profile has changed, and the amount due to a lack of economic outlets has increased. In the early 2000s,

10. This is one of the major goals of the START 2025 programme implemented by EDF between 2019 and 2025, which aims to optimise reactor shutdowns and make them more reliable in order to maximise production from the fleet.

11. The operation of a reactor core obviously imposes an upper limit on the interval between two refuelling operations (based on inventory constraints), but also a lower limit, which is due to safety requirements involving the residual radioactivity in the nuclear fuel being replaced. This must not exceed a certain limit: if the reactor is refuelled too early, the threshold is exceeded.

**Figure 2.12 – Average proportion of the nuclear fleet modulating its output (in terms of power relative to installed capacity) by time of day, over a sample of years***




** Temporary power reductions. Reactor shutdowns are not counted.*

modulation mainly took place at night during the summer. Recently, the phenomenon has been more prevalent in the afternoons, particularly at weekends between April and October (when prices are lower). The changes associated with this new modulation landscape in the nuclear fleet were documented in detail in the 2025 Generation Adequacy Report.

Finally, environmental constraints in 2025 led to a reduction in production of less than one terawatt-hour. The effects associated with this factor thus remained limited this year, as did the effect of strikes[12] (also less than one terawatt-hour) and network constraints (negligible volumes).

12. In some years, strikes can represent a substantial loss of production. This was the case in 2009 and 2023, for example. The Commission de régulation de l'énergie estimates the impact in those years at 15 to 20 TWh.

# After benefiting from exceptional rainfall in 2024, hydropower generation fell in 2025 but remains in line with historical averages

After reaching a level in 2024 that had not been seen since 2013, hydropower generation fell sharply in 2025 (–12.9 TWh/–17.2%), reaching 62.4 TWh, a level close to the average annual output over the last decade (61.4 TWh on average between 2015 and 2024).

The fall in hydropower generation between 2024 and 2025 essentially reflects lower rainfall in 2025 than in 2024: whereas 2024 was one of the ten wettest years since 1959, cumulative rainfall in 2025 was close to the norm[13].

**Figure 2.13 – Hydropower generation in France between 2014 and 2025**

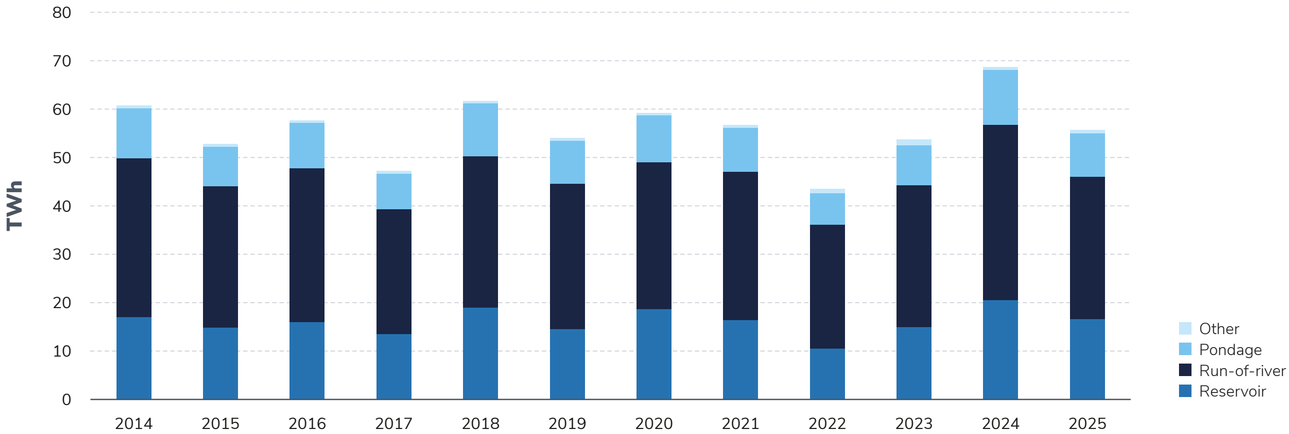
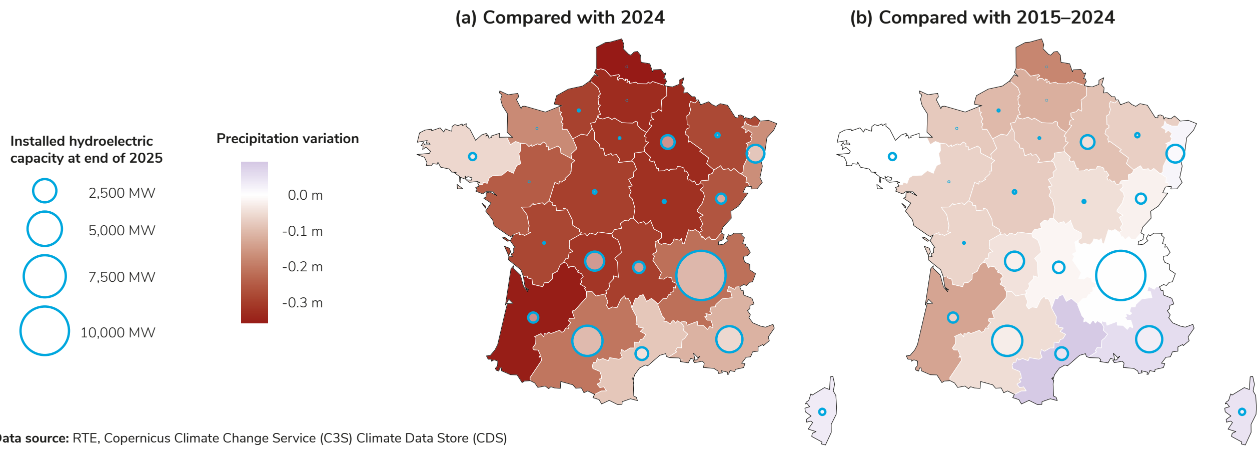



**Figure 2.14 – Variations in average precipitation over the year 2025**




**Data source:** RTE, Copernicus Climate Change Service (C3S) Climate Data Store (CDS)

13. Météo France, 2025: *les bilans climatiques*, January 2026. The Météo France norm is defined over the period 1991–2020.

# Onshore wind generation rose slightly in 2025 and installed capacity continues to grow, but at a slower pace

## Onshore wind generation increased slightly in 2025 despite an exceptionally low load factor

After falling by more than 10% in 2024, onshore wind generation recovered slightly in 2025, reaching 43.9 TWh (+1.1 TWh/+2.5% compared with 2024). This shift was due to growth in onshore wind capacity over the course of the year, and to wind conditions in 2025 that were broadly similar on average to those in 2024 across mainland France (with an improvement in the western and central regions and a slight decline in the north and east of France), although they remained unfavourable compared to the average over the previous decade (see below).

**Figure 2.15 – Onshore wind generation between 2010 and 2025**

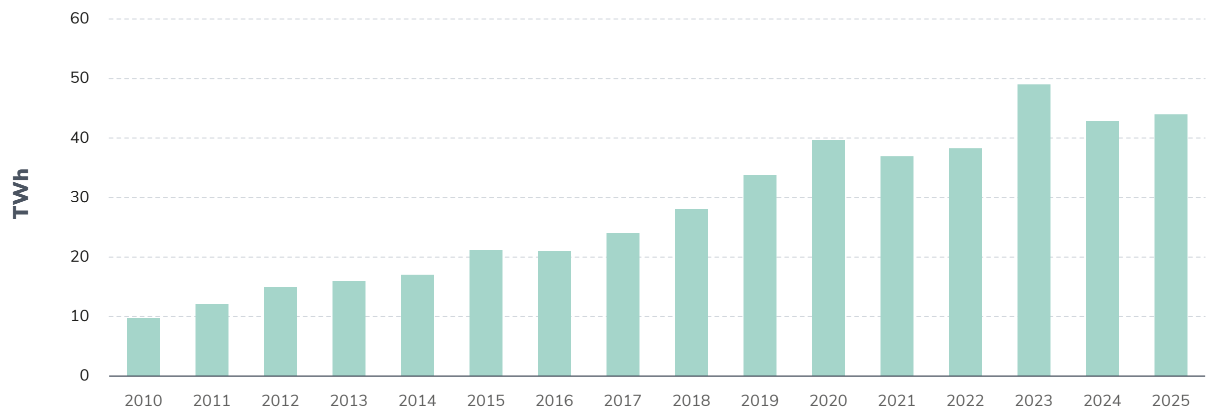



**Figure 2.16 – Annual average coverage rate of consumption by onshore wind generation between 2014 and 2025**

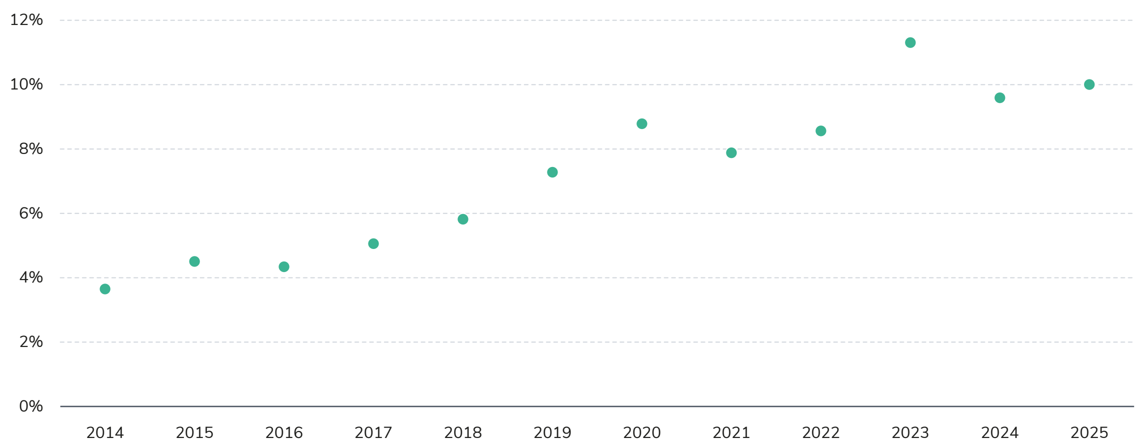
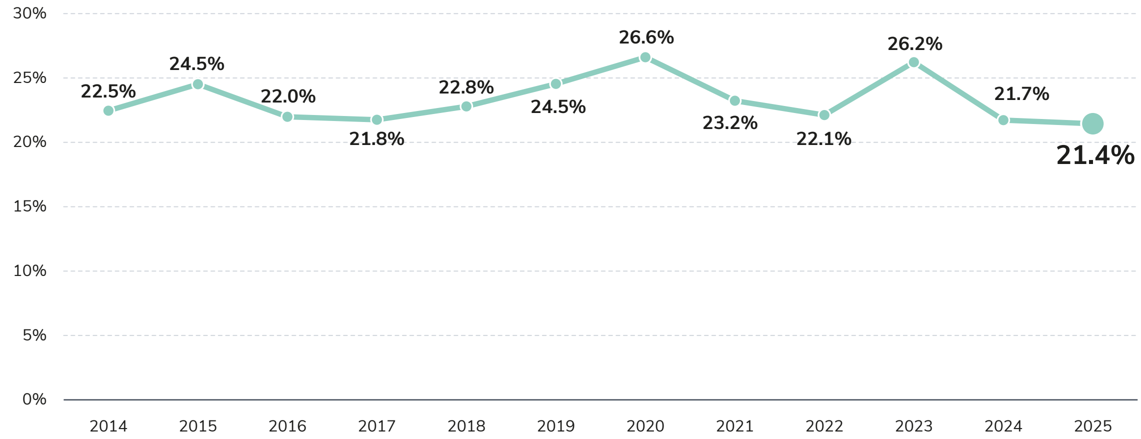


**Figure 2.17 – Change in annual load factor for onshore wind power between 2014 and 2025**

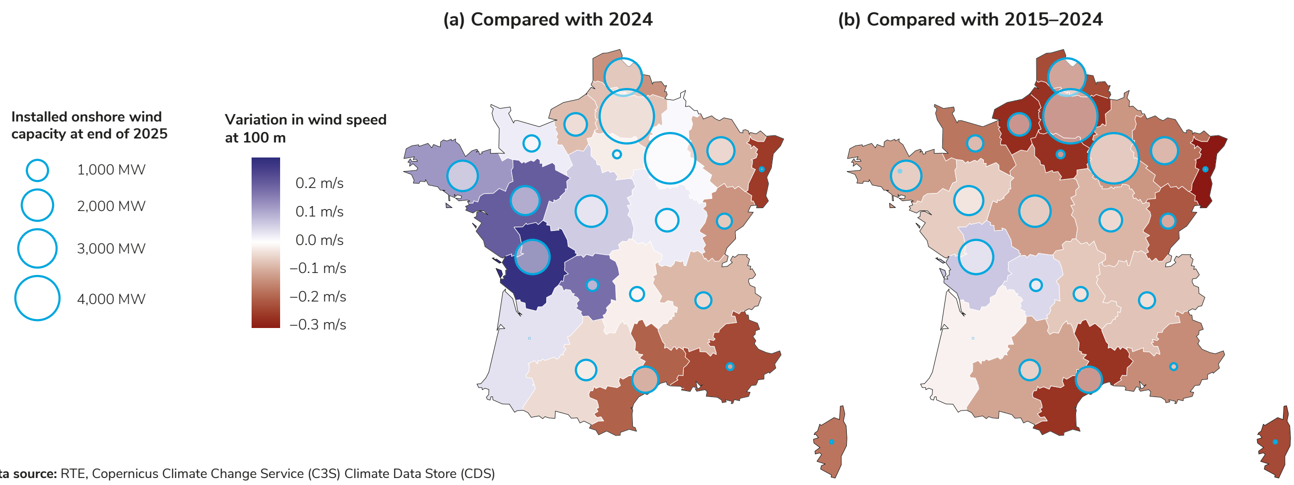



On average over 2025, output from onshore wind covered around 10.0% of national consumption. This coverage rate was slightly up on the previous year (9.6% for 2024) due to the relative stability of gross consumption.

The load factor for French onshore wind power was 21.4% in 2025. This is an exceptionally low level, following a decline that had already been seen in 2024.

The low load factor for onshore wind power is primarily due to wind conditions. The average wind speeds recorded in 2025 were below their average levels over the last decade for the whole of mainland France, except in the north of the Nouvelle-Aquitaine region. This wind deficit was more pronounced in the northern half of France, where most of the onshore wind capacity installed on the mainland is concentrated.

**Figure 2.18 – Variations in average wind speed over the year 2025**



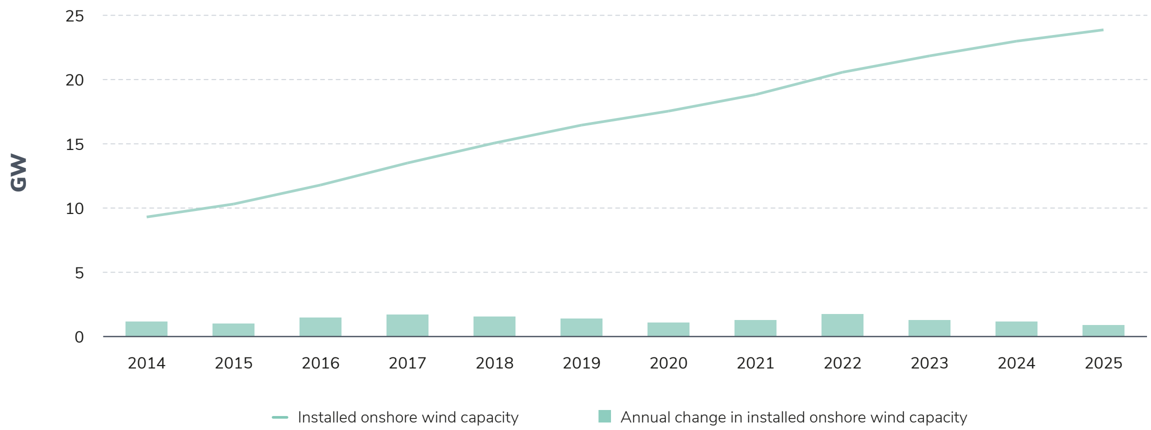

**Data source:** RTE, Copernicus Climate Change Service (C3S) Climate Data Store (CDS)

Over the course of 2025, French onshore wind farms occasionally modulated their output downwards, either in response to economic incentives during episodes of negative spot prices (the majority by volume), or when RTE called on them to guarantee the balance of the power system (for more limited volumes; see the "Modulation" section). Over 2025, these modulations created a downward effect on onshore wind generation of around 1.3 TWh, more than a third higher than the estimated level for 2024. Overall, modulation of onshore wind generation – whether in response to economic market conditions or at RTE's initiative – was responsible for a drop of around 0.7 points in the load factor compared with a theoretical situation with no modulation.

## Onshore wind farm growth slows for the third year running

At the end of 2025, onshore wind capacity in operation in mainland France represented 23.9 GW. With a further 0.9 GW coming on stream in 2025, France's onshore wind fleet continued to expand. However, the rate of growth slowed in 2025 for the third year running, reaching its lowest level since 2013.

**Figure 2.19 – Development of French onshore wind capacity**



# Offshore wind generation is still growing

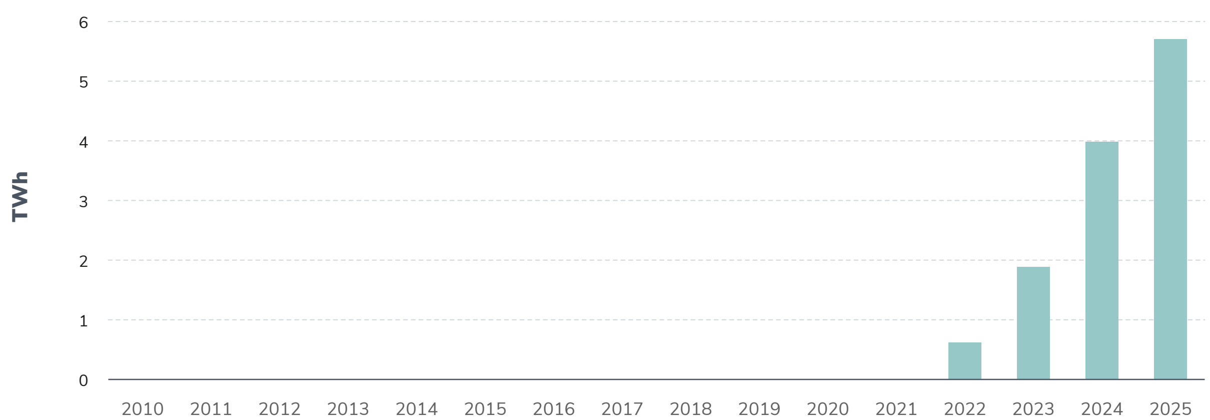
## The growth of the offshore wind fleet has increased its output

French offshore wind generation in 2025 stood at 5.7 TWh, an increase of almost 43% (+1.7 TWh) compared with the 2024 level.

This increase largely reflects growth in offshore wind capacity. The Saint-Brieuc and Fécamp offshore wind farms were gradually commissioned over the course of 2024, and their entire installed capacity (just under one gigawatt for the two farms combined) has been operational since May 2024. In 2025, a fourth commercial wind farm whose turbines are installed offshore off the islands of Yeu and Noirmoutier was gradually brought on stream (411 MW out of a total of 488 MW were operational by the end of 2025). In addition, the 25 MW of France's first floating offshore wind farm pilot[14] were commissioned in June 2025 in the so-called “Faraman” zone, 17 km off the coast of Port-Saint-Louis-du-Rhône. As of 31 December 2025, the total installed capacity of the offshore wind fleet off French mainland coasts was 1.9 GW.

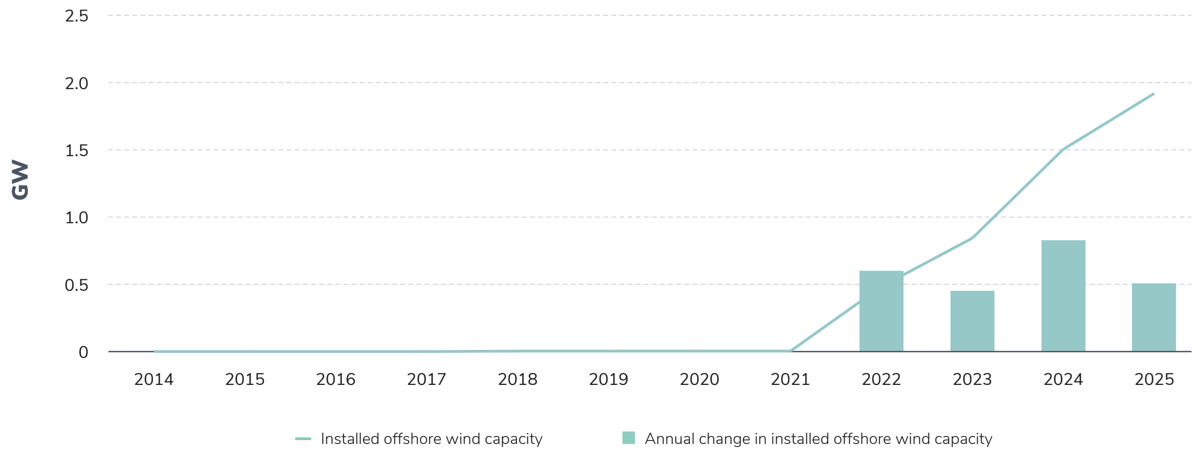
The load factor for commercial offshore wind farms[15] commissioned before 1 January 2025 was 38.8% over 2025 as a whole[16]. In 2024, the load factor for the Saint-Nazaire wind farm, the only one operating at full capacity for that year, was 32.9% (compared with 36.3% in 2025). The increase in the load factor for French wind power is due both to the commissioning of new wind farms in more favourable locations and to the higher availability of the Saint-Nazaire wind farm in 2025 compared with 2024[17].

**Figure 2.20 – Offshore wind generation between 2010 and 2025**




14. Some prototype offshore wind turbines have already been tested and connected to the grid since 2018, notably off the coast of Le Croisic.
15. Wind power generated at the SEM-REV test site is excluded from this calculation.
16. These are the Saint-Nazaire, Fécamp and Saint-Brieuc wind farms.
17. The downtime declared for the Saint-Nazaire wind farm in 2025 was around 20% less than the previous year.

**Figure 2.21 – Development of French offshore wind capacity**




Offshore wind capacity off the French coast is set to continue growing in 2026 with the commissioning of around 450 MW of wind turbines off Courseulles-sur-Mer and 60 MW of floating wind turbines at two sites off Leucate and Gruissan.

# Solar generation increased significantly in 2025 due to more favourable sunshine conditions than in 2024 and the increase in installed capacity

**Benefiting from more favourable sunshine conditions and growth in the installed base, French solar output rose sharply in 2025.**

French solar generation stood at 32.9 TWh in 2025, up 32.7% on the 2024 level.

Electricity generation from the solar sector covered an average of 7.5% of consumption in mainland France in 2025. This rate has gradually increased over the last decade, in line with the momentum of solar generation.

**Figure 2.23 – Solar generation between 2010 and 2025**

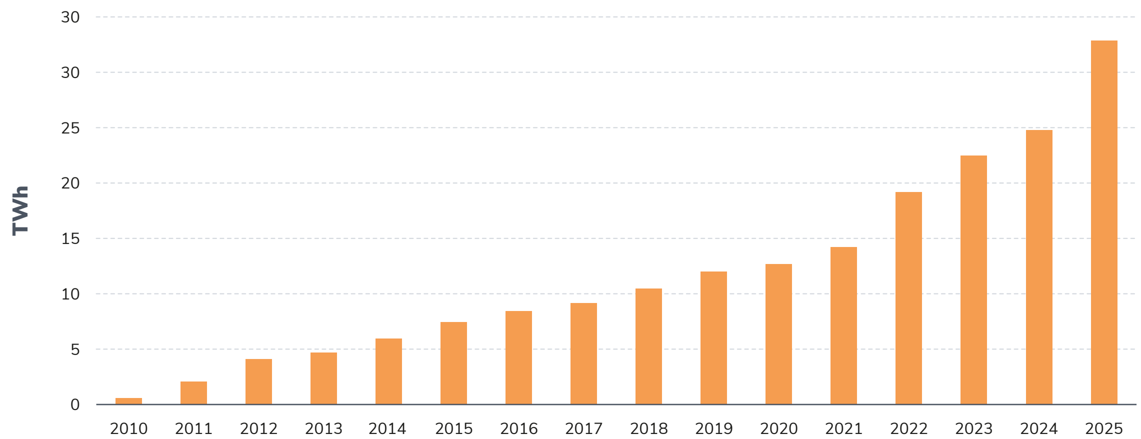



**Figure 2.24 – Annual average coverage rate of consumption by solar generation between 2014 and 2025**

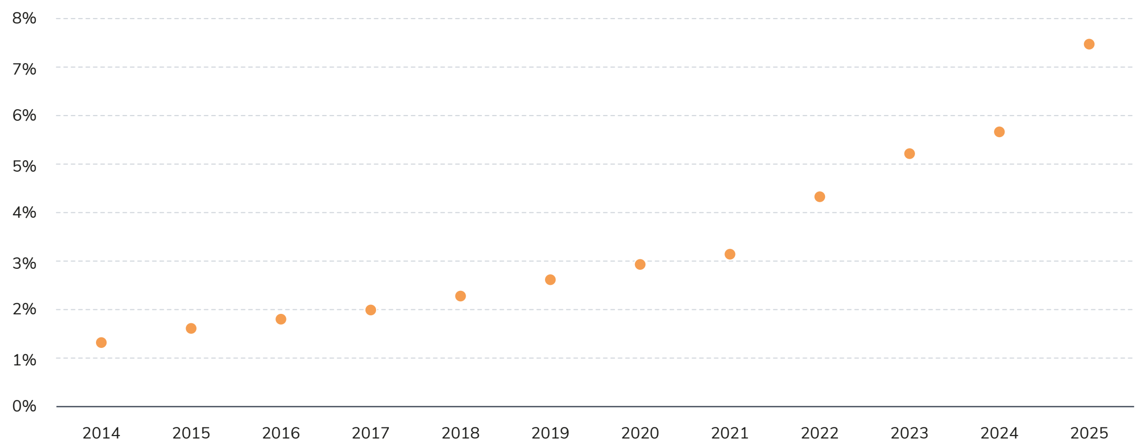
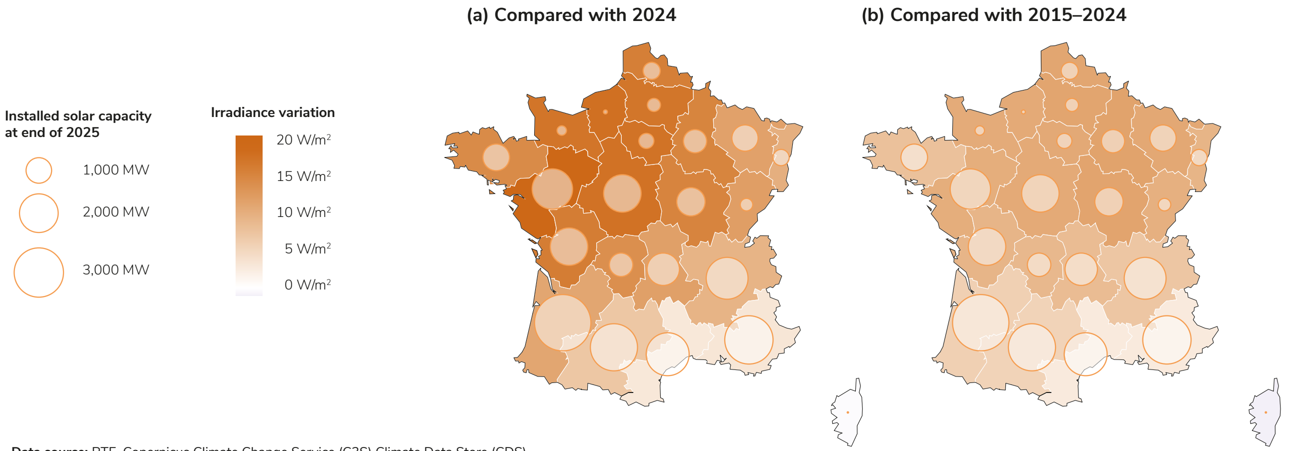


**Figure 2.25 – Variations in sunshine over the year 2025**

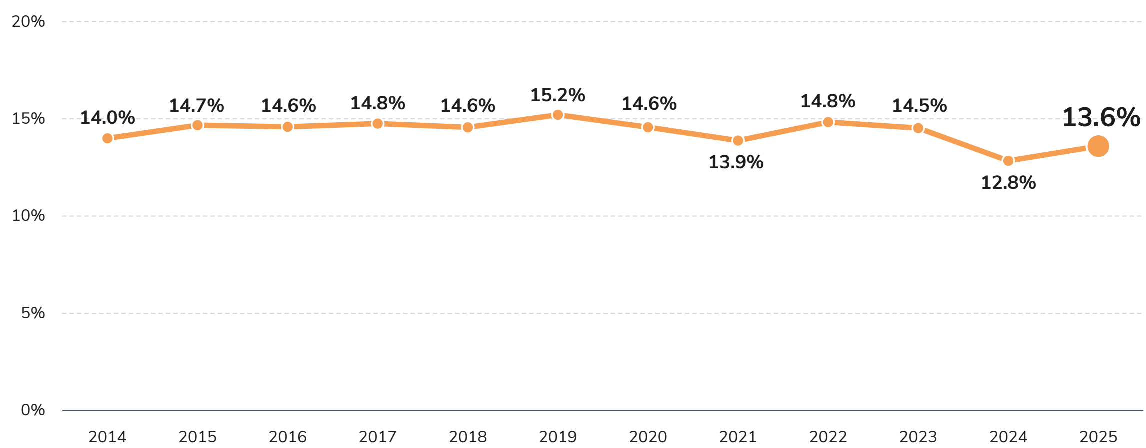



**Data source:** RTE, Copernicus Climate Change Service (C3S) Climate Data Store (CDS)

The increase in French solar output results from growth in installed solar capacity (see below) and the significantly better sunshine conditions in 2025 than those experienced in mainland France in the previous year: whereas 2024 was one of the least sunny years that France has seen over the last thirty years, sunshine over the year in 2025 was slightly higher than the average for the previous ten years (2015–2024)[18]. The surplus sunshine over the past year was more pronounced in the northern half of mainland France than in the south, where most of the country's solar electricity generating capacity is concentrated.

The improvement in sunshine conditions resulted in a sharp rise in the average annual load factor for the French solar fleet, which stood at 13.6% in 2025, compared with 12.8% in 2024. However, the load factor for solar power in 2025 was still below its ten-year average (14.4%), despite slightly more sunshine

**Figure 2.26 – Change in annual load factor for solar power between 2014 and 2025**




18. Sunshine is quantified here by the irradiance value.

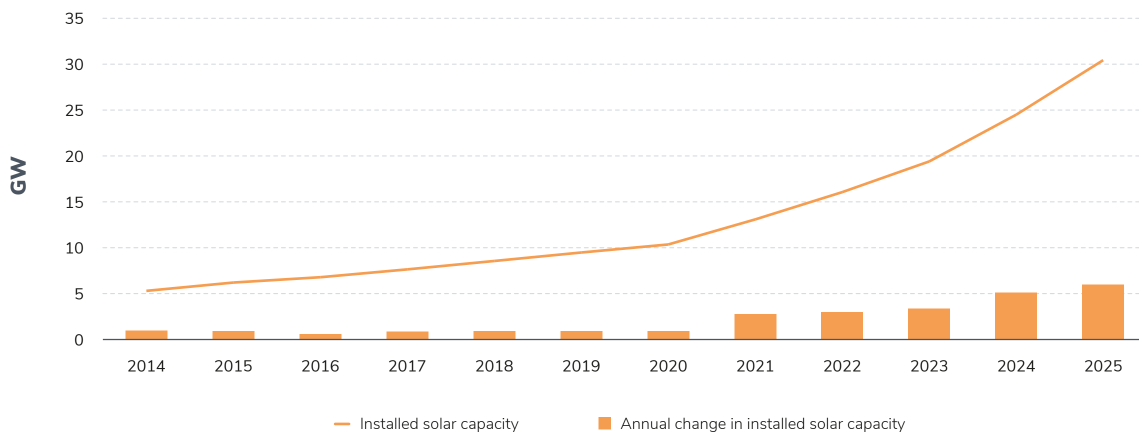
than normal. This relative weakness is partly due to the fact that French solar producers modulated their output downwards more in 2025 – in response to economic incentives during periods of negative spot prices or at the request of RTE to guarantee the balance of the power system – than they have done historically (see the “Modulation” section). Modulation of solar power represented around 1.6 TWh in 2025 (RTE estimate), i.e. almost two and a half times more than in 2024. This modulation was responsible for a drop of around 0.8 points in solar power's load factor in 2025 compared with a theoretical situation with no modulation.

## Solar capacity continues to grow at a strong pace

At the end of 2025, the cumulative capacity of solar power generation facilities in mainland France was 30.4 GW. Over 2025, 5.9 GW of new capacity was installed, continuing the acceleration in the growth of French solar capacity observed since 2021.

Due to the hourly profile of solar generation, with a peak in the late morning lasting until early afternoon, the growth of solar capacity in France and Europe has distorted the hourly profile of electricity prices, resulting in low or sometimes negative prices during these times, particularly in the spring (see the “Prices” chapter). This reveals a need to develop the flexibility of the power system to guarantee that supply and demand are balanced, in terms of both generation flexibility (the downward modulation of renewable production, for example, which must be controlled to avoid too-sudden variations) and consumption flexibility. In particular, the peak/off-peak signal system introduced in the 1960s has been adapted to include the early afternoon among the off-peak hours.

**Figure 2.27 – Growth in the French solar power installed base**



# Renewables are making a growing contribution to grid flexibility

**The volume of modulation by solar and wind farms during periods of negative spot prices doubled in 2025 compared to the previous year.**

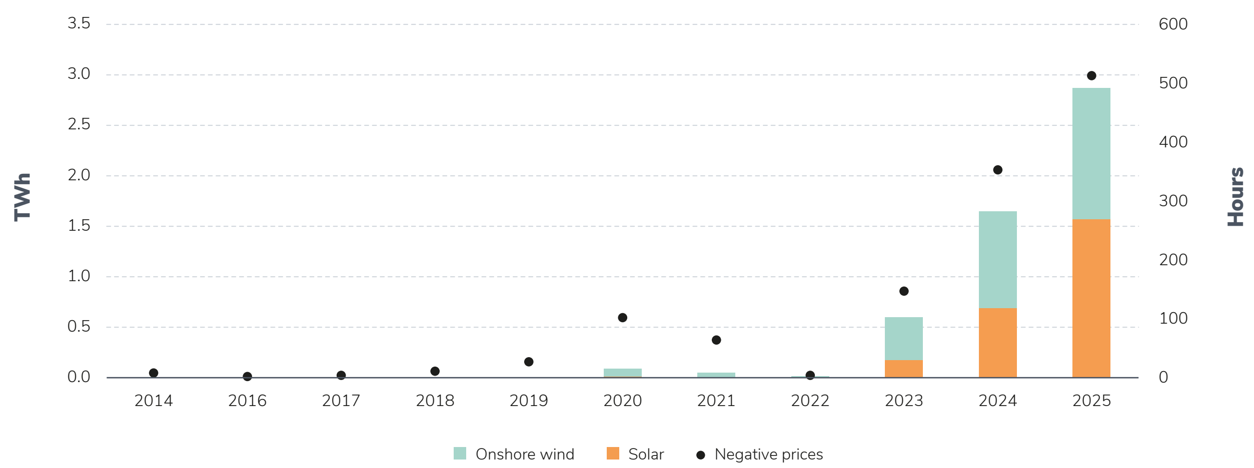
Negative spot prices result from anticipation of surplus generation compared with consumption and trading forecasts. These negative prices then constitute an economic signal incentivising all producers who have the technical capacity to do so to reduce their output or stop generating. This incentive applies in particular to nuclear power units (which modulate their output based on market prices), dispatchable hydroelectric capacity, storage facilities and a proportion of solar and wind generation.

In 2025, episodes of negative prices led to around 3 TWh[19] of solar and wind output not being generated. This is almost double the 2024 volume.

The increase in the modulation of wind and solar generation during negative price episodes between 2024 and 2025 is linked to negative prices occurring more frequently (see the "Prices" chapter), the strong increase in solar generation (in France and the rest of Europe) and the growth of capacity that can be curtailed during negative price episodes.

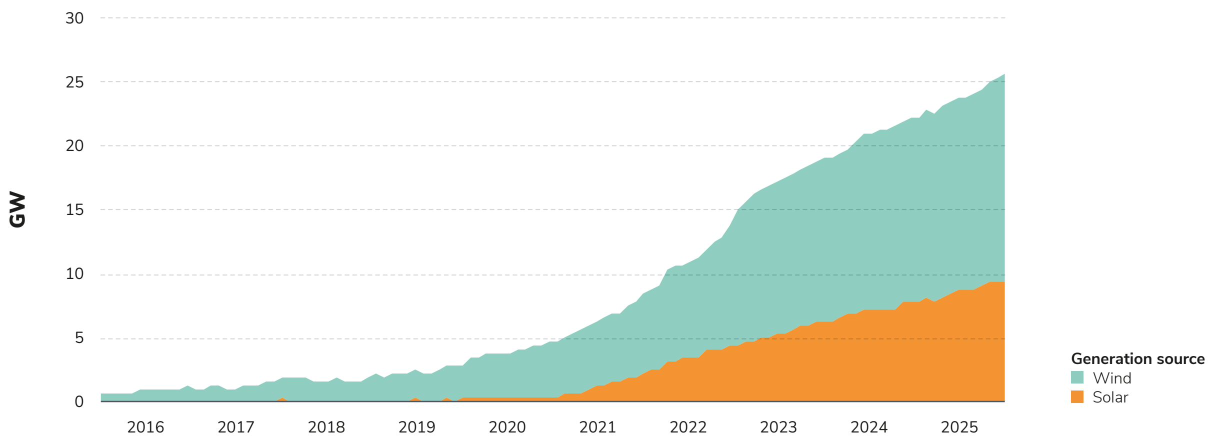
The majority of onshore wind capacity and some photovoltaic installations are now being developed under the premium scheme ("*complément de rémunération*"). This framework includes incentives for the installations involved to stop production when the spot price is negative. Capacity developed under the premium scheme, like non-supported installations[20], is therefore likely to stop generating during periods of negative spot prices. Between 2024 and 2025, this capacity increased by 3.3 GW.

**Figure 2.28 – Estimated solar and wind modulation volumes during negative price periods**




19. 1.3 TWh of onshore wind generation and 1.6 TWh of solar generation (RTE estimate).
20. Not all non-supported installations necessarily have an incentive to stop generating when a negative market price occurs. For example, the current regulatory framework does not require PPAs to include a clause obliging the installation to stop or limit their output in the event of negative prices.

**Figure 2.29 – Solar and wind capacity able to shut down during negative price periods**




**Data source:** EDF OA, RTE

The remainder of the wind and solar fleets are covered by purchase obligation contracts[21]. Historically, the arrangements for remunerating generation under these contracts have not encouraged producers to modulate their output in line with market prices. However, since the end of December 2025, solar and wind installations with an installed capacity of more than 10 MW[22] have had a financial incentive to reduce or stop their production at the request of buyers with purchase obligations[23]. This provision could therefore lead to some wind and solar farms with purchase obligation contracts curtailing their output during periods of negative spot prices from 2026 onwards.

The modulation of renewable output contributes to the balance of the power system, but this must now be controlled in order to ensure the balance between supply and demand is managed safely in as near-real time as possible. Stopping or restarting very large amounts of generation at the same time can lead to frequency disruptions, risking the operation of the system, or to the use of costly adjustment resources. The 2025 Finance Act and its implementing decree of December 2025 introduced a number of measures aiming to smooth renewable generation shutdowns and restarts, whether they are caused by negative price signals or a buyer with a purchase obligation.

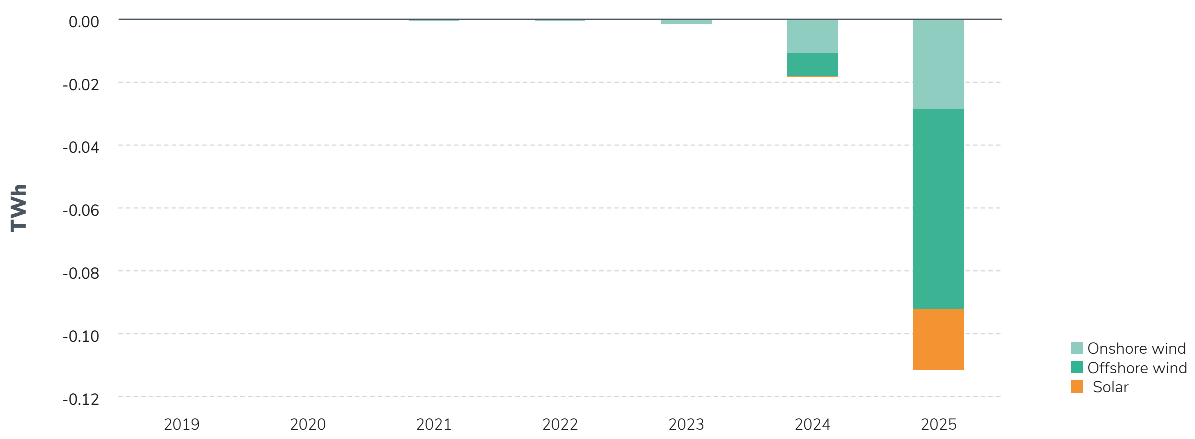
## As a result of regulatory changes, solar and wind capacity contributed more to the real-time balancing of the power system in 2025

The legislator has given RTE responsibility for balancing electricity supply and demand[24]. As a result, RTE can request generation adjustments in as close to real time as possible to guarantee the safety of the power system. In particular, when the decisions taken by market players result in surplus power generation, RTE can order cuts in output. Solar and wind capacity can now be called on to adjust their output downwards in order to guarantee the balance of the power system.

Downward adjustments requested by RTE in 2025 led to the curtailment of 0.1 TWh of solar and wind generation. Although the contribution of wind and solar to the total downward adjustments requested

21. Historically, these contracts have been the primary mechanism for the development of renewable electricity generation facilities. They are now reserved for solar installations developed via the “open window” (“*guichet ouvert*”) system.
22. Or 12 MWp for installations whose installed capacity is defined in megawatts-peak
23. The principle of this incentive was introduced in Article 175 II of France’s finance act 2025-127 on 14 February 2025. The provision came into force following the implementing order of 22 December 2025.

**Figure 2.30 – Generation adjustments for wind and solar power**




by RTE over the year as a whole remained moderate compared to other power sources[25], the volumes of solar and wind generation adjusted rose sharply. Their level in 2025 was almost five times higher than in 2024, while the downward adjustments made by RTE across the generation mix remained stable over the same period (+0.3%).

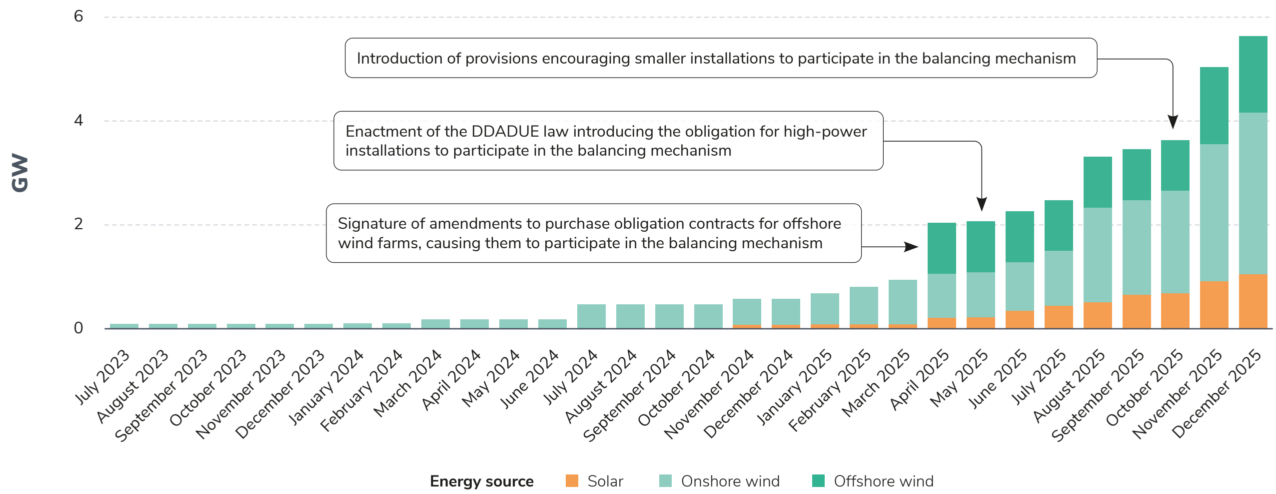
The greater reliance on wind and solar to guarantee the balance of the power system is partly due to the fact that the volumes generated by hydropower and thermal plants fell significantly between 2024 and 2025, reducing the scope for these facilities being called on to adjust their output downwards. It also coincides with increasing participation by these installations in the balancing mechanism. **The wind and solar capacity that can be mobilised under this mechanism has increased tenfold over the past year, reaching almost 5.6 GW by the end of 2025.** This growth results from successive changes to the legal framework over the course of 2025.

The 2025 Finance Act of 14 February 2025 enabled all plants supported by a purchase obligation or the premium scheme to take part in the balancing mechanism. This option has been available since 1 October 2025 and applies across the generation mix regardless of power thresholds. Participation in the balancing mechanism was even made compulsory by the “DDADUE” law passed at the end of April 2025[26], which introduces an obligation for all installations with a capacity greater than 10 MW[27] – including solar and wind farms – to offer as much capacity as is technically available to the balancing mechanism. This obligation came into force on 1 January 2026, and some players were able to comply earlier.

At the same time as these legal and regulatory changes, amendments to the purchase obligation contracts for the Saint-Nazaire, Fécamp and Saint-Brieuc offshore wind farms meant that these farms have participated in the balancing mechanism since

24. Article L. 321-10 of the French energy code.
25. In 2025, downward adjustments in the wind and solar sectors accounted for just under 2.5% of the generation cuts requested by RTE across the energy mix.
26. Article 18 of French law no. 2025-391 of 30 April 2025
27. The value of this threshold was proposed by RTE and established by CRE in its deliberation of 2 December 2025: CRE, Délibération n° 2025-266, 2 December 2025

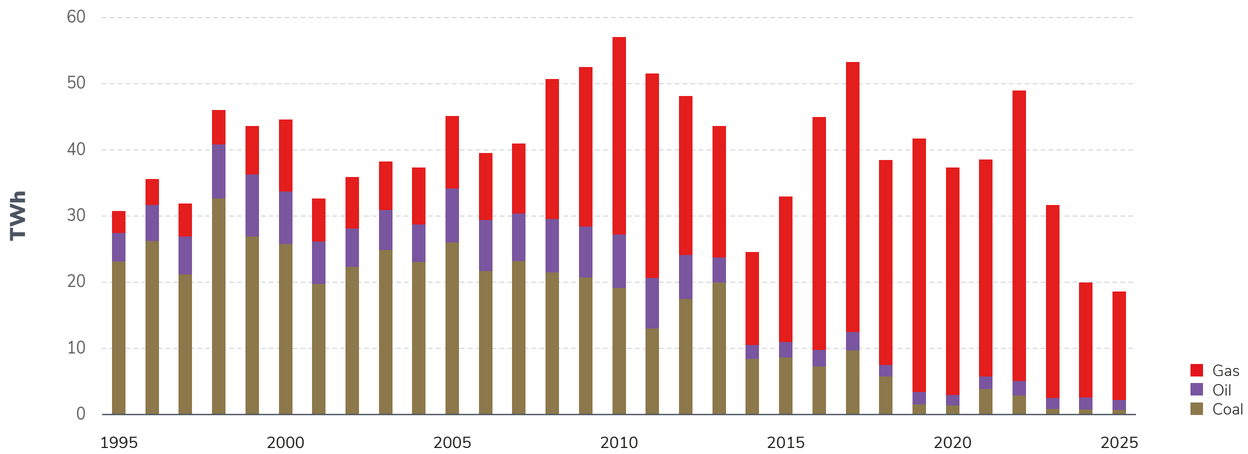
**Figure 2.31 – Wind and solar capacity participating in the real-time balancing mechanism (at RTE's request)**




spring 2025. As a result, adjustments to offshore wind generation at RTE's initiative (via the balancing mechanism or emergency orders) amounted to 63.8 GWh in 2025, a clear increase compared to 2024 (7.2 GWh), the first year in which RTE resorted to downward adjustments to offshore wind generation to ensure the balance of the power system.

# Fossil-fired thermal power generation in France reached a new historic low for the second consecutive year

**Figure 2.32 – Electricity generation from fossil fuels in France between 1995 and 2025**




French fossil-fired electricity generation totalled 18.7 TWh[28] in 2025. For the second year running, this was the lowest level since the early 1950s; in 2024, fossil-fired generation stood at 19.9 TWh, which was already the lowest total recorded during this period.

**Gas, coal and oil-fired power stations, which are by far the most emissions-intensive, generated less than 4% of the total electricity generated in France in 2025.** While the French electricity mix as a whole has long been low-carbon thanks to the major contribution from hydroelectric and nuclear power, fossil-fired generation still accounted for around 10% of production at the turn of the 2010s, with around a third from coal.

The momentum seen since then leads to two conclusions: firstly, fossil-fired generation as a whole is now almost residual in the French mix; and secondly, of the three main conventional fossil fuels, **gas, by far the least emissions-intensive, now accounts for the bulk (87%) of the remaining fossil-fired generation in France. Electricity generated using oil and coal has almost entirely disappeared:** in 2025, these two generating sources accounted for 1.7 and 0.7 TWh respectively, less than the electricity produced from biogas.

28. Electricity generated from gas, coal and oil.

# A large proportion of gas-fired generation comes from inflexible resources that operate independently of the power system

Gas-fired generation is usually divided into three main categories in terms of their place in the power system and their operation:

- combined-cycle gas turbines (CCGTs): these are power stations that combine a combustion turbine with a steam turbine (which uses the heat from the first turbine's exhaust gases); this is the most modern technology and offers the best efficiency (between 50 and 60%) and thus the lowest emission intensity of all fossil fuels. This category accounts for most of the so-called “dispatchable” gas-fired generation in France. The marginal cost of CCGTs is competitive compared with other fossil-fired generation methods, which means that they can be called on during periods of high consumption, such as in winter or, to a lesser extent, during heatwaves. The Landivisiau plant, the most recent to be commissioned in France in the summer of 2024, falls into this category;
- conventional gas-fired power plants, including combustion turbines: these are less optimised because, unlike CCGTs, they are based on an open cycle, i.e. with no recovery of the heat produced during combustion. This makes them less efficient (between 30 and 40%) and their output is more emissions-intensive. France generates very little electricity at this type of plant: they only operate at peak times or, in some cases, to contribute to the short-term balancing of the power system or to resolve network pressures;
- cogeneration[29]: this refers to facilities that produce both heat (e.g. for industrial needs) and electricity. For this type of installation, electricity generation is generally secondary to heat production. They are usually attached to a main installation, often a district heating network, or sometimes an industrial facility. Output from cogeneration is characterised by the fact that it is driven by the heat requirements of the underlying process, and depends to a lesser extent on the economic conditions that govern electricity generation in the short term. From the viewpoint of the power system, therefore, this is partly inflexible generation.

Based on this categorisation, gas-fired generation can be broken down broadly into two parts:

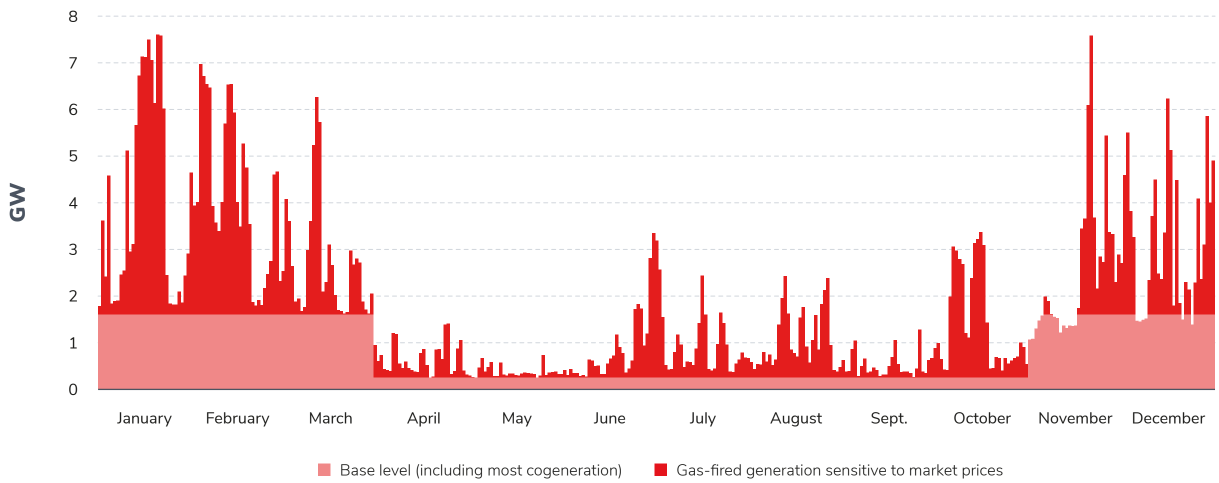
- a “base” level corresponding to the continuous output of the different types of cogeneration. As cogeneration linked to heating networks accounts for a large proportion of cogeneration in France, this base level varies according to the season: for 2025[30], it is estimated at around 1,600 MW during the heating period (between November and April), and 250 MW in summer (a level that corresponds more to industrial cogeneration of various kinds);
- in addition to this base level, a dispatchable or market-sensitive portion, essentially made up of CCGTs and, to a lesser extent, conventional power plants, including combustion turbines.

There are also hybrid systems, which operate in specific ways, with part of their output as the base level but with the possibility of increasing their production beyond this base if the economic conditions justify it. This is the case, for example, with the Dunkirk combined-cycle gas power plant (see below).

29. The essential distinction for the analysis of the power system relates to the inflexible nature of the electricity generated. Cogeneration plants may use a variety of electricity generation technologies, including CCGTs or conventional power plants.

30. For certain installations capable of cogeneration, whether or not they generate electricity may depend, among other things, on the terms of public support, and in particular the purchase obligation scheme. In recent years, this support has tended to erode: every year, the equivalent of around 250 MW of electricity generating capacity leaves the scheme. This can lead the installations concerned to reorient their business model and stop generating electricity, which necessarily reduces the base level from year to year. This is also the reason behind the very slight drop in gas-fired capacity.

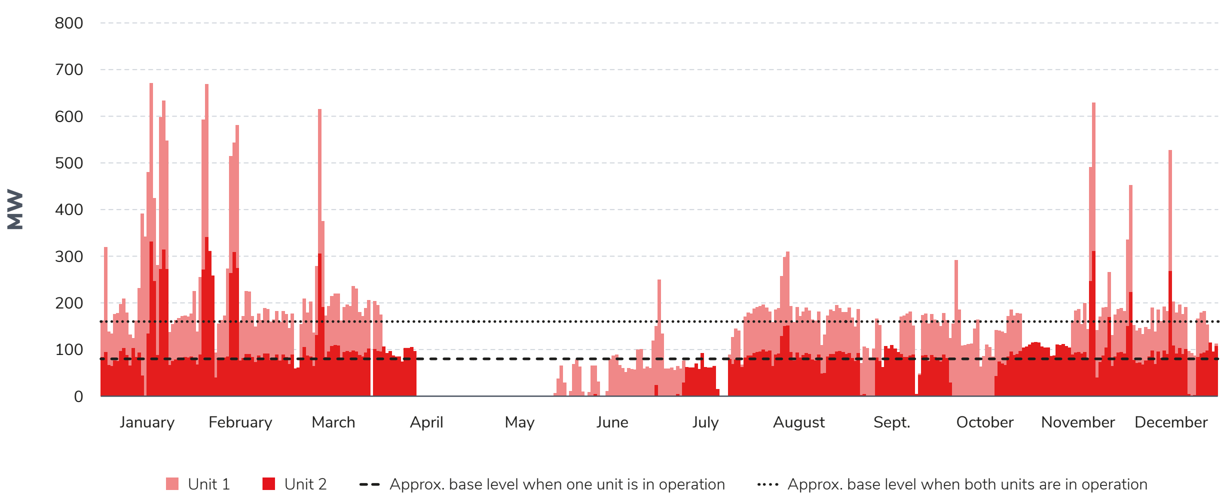
Figure 2.33 – Average daily level of gas-fired generation in 2025




In 2025, gas-fired power plants generated a total of 16.4 TWh. The volume of generation that can be considered as operating independently of the power system is around 7 TWh, or just under half. This corresponds to the output of cogeneration, and other thermal sources whose behaviour can be likened to cogeneration. The rest of gas-fired generation comes essentially from CCGTs. In other words, the generation actually called on in order of economic precedence represented only 9 TWh, or less than 2% of all the electricity generated in France.

Some CCGTs linked to industrial sites can also choose to increase their production beyond the base level due to cogeneration from industrial processes, depending on a trade-off between market prices and the constraints of the industrial processes to which they are linked. This is the case with the Dunkirk combined-cycle power plant (also known as DK6), for example. This plant, with a total capacity of around 800 MW, consists of two CCGTs connected to the ArcelorMittal steelworks, from which they recover some of the steelmaking gases. When

Figure 2.34 – Illustration of hybrid operation at the Dunkirk power plant



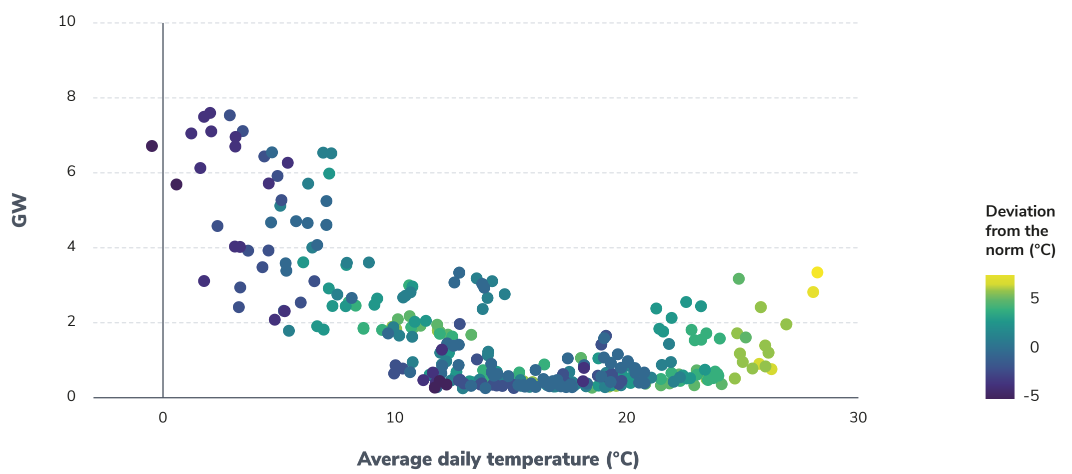
operating solely to burn steelmaking gases, the two units produce around 80 MW each continuously; when market conditions[31] justify it, the plant can increase its output to its maximum capacity (almost 800 MW). These two levels, as well as the periods of highest output and periods of complete or partial shutdown of the site, are clearly visible in the annual production profile (Figure 2.34). Analysis shows that the DK6 plant very rarely operated beyond the base level linked to the combustion of steelmaking gases in 2025, indicating that market conditions causing the plant to start up at its rated output were infrequent.

## Gas-fired generation takes place mainly on days when consumption is highest

The majority of gas-fired generation, mostly combined-cycle plants, takes place during clearly defined periods, corresponding to periods of high consumption, and particularly high residual consumption[32]. This is true in winter, when these situations are most frequent, but also – more occasionally and to a lesser extent – in summer, particularly during hot spells[33]. For example, a third of annual gas-fired generation is concentrated on the coldest 10% of days, representing around 35 days.

Finally, there is a slight inverse relationship between the level of gas-fired generation in France and exports: the highest levels of exports are recorded when gas-fired generation is at its lowest.

**Figure 2.35 – Average daily output of gas-fired power stations as a function of average daily temperature**




31. The trade-off can be complex; it is based on a combination of the market conditions for electricity and gas, plus industrial constraints.
32. Residual consumption corresponds to total consumption minus inflexible generation , i.e. essentially wind, solar and run-of-river hydropower generation. Although it is essentially inflexible, output from cogeneration plants is not usually counted when calculating residual consumption.
33. This is also the period when nuclear fleet availability is generally at its lowest.

# Battery development in France remains modest and is still limited to the provision of system services

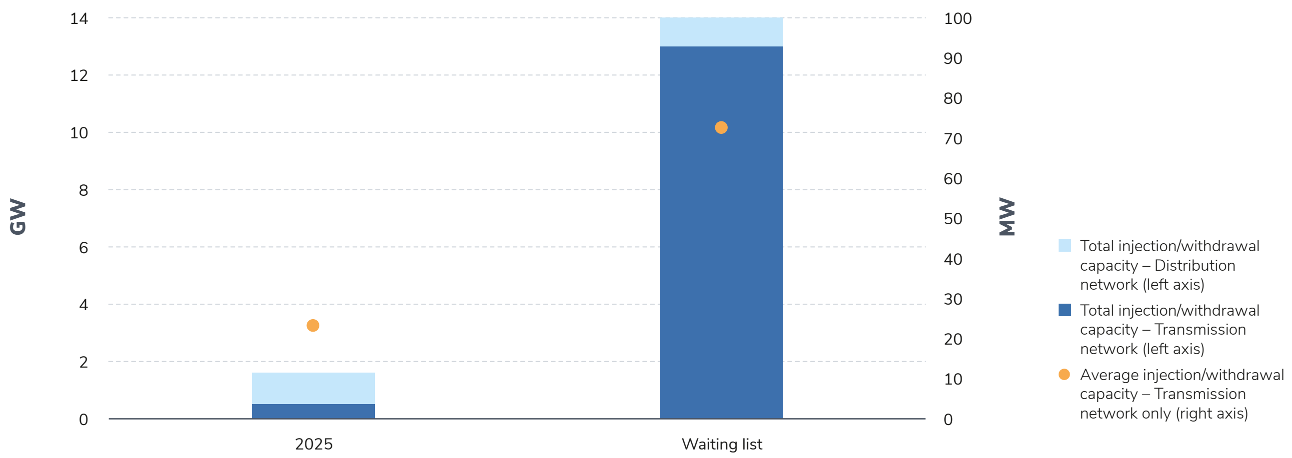
On 31 December 2025, total battery storage in service in France amounted to 1.6 GW. Around a third of this capacity is connected to the transmission network, and the rest to the distribution network. In principle, the higher the voltage level, the higher the capacity of the installation. The majority of batteries in service in France today are thus of modest size, in the megawatt range. The most powerful batteries, connected to the transmission grid, are few in number (just over 20 at the end of 2025).

Diffuse batteries, i.e. small-capacity, low-voltage batteries installed in homes or small businesses, are underdeveloped in France, with a total of just 140 MW[34]. In other countries, this type of installation represents a significant proportion of ambitions for the growth of storage (see the *Europe* chapter).

For more powerful batteries, the waiting list, i.e. projects for which developers have already secured access to the grid, had reached around 14 GW by the end of 2025[35]. Most of these projects are connected to the electricity transmission network (high and very high voltage).

It now seems clear that not all of these projects will come to fruition[36], or at least not in the next few years: as with all types of grid connection projects, most of the projects on the *waiting list* have not yet reached the point of a final investment decision. Analysing the battery connection waiting list in detail suggests that this sector is likely to develop in a very different way from what has been seen so far. The general trend is towards bigger installations: almost 90% of the total capacity on the waiting list involves transmission

**Figure 2.36 - Total injection/withdrawal capacity of batteries in service in France and injection/withdrawal capacity of waiting list projects**




34. Source: consolidated RTE data based on internal data and data provided by distribution system operators.
35. Storage projects will now be added to the waiting list after the project applicant has accepted a technical and financial proposal from the relevant network operator.
36. In addition, the completion rate is one of the underlying assumptions used in grid development studies. This rate depends on many factors, including general economic conditions, the specific economic conditions of the sector and the development of other components of the power system (consumption, generation, etc.).

system connection projects. This corresponds to around 180 projects. Even within the transmission system, the size is tending to increase, with an average capacity of almost 75 MW for projects on the waiting list compared with an average of 25 MW for the batteries already connected to the transmission network.

Generally speaking, battery storage installations can take part in a wide range of mechanisms and markets:
- providing system services, such as frequency regulation;
- taking part in wholesale markets, and particularly intraday markets: this involves storing surplus generation at certain times of the day and releasing it during daily consumption peaks. The typical example of this type of use is to take advantage of solar power, which is often in surplus in the middle of the day;
- contributing to the management of network pressures;
- taking part in the capacity mechanism, and thus in ensuring security of supply.

Today, however, the main activity of the batteries already in service in France is still the provision of system services, and particularly system services linked to frequency regulation.

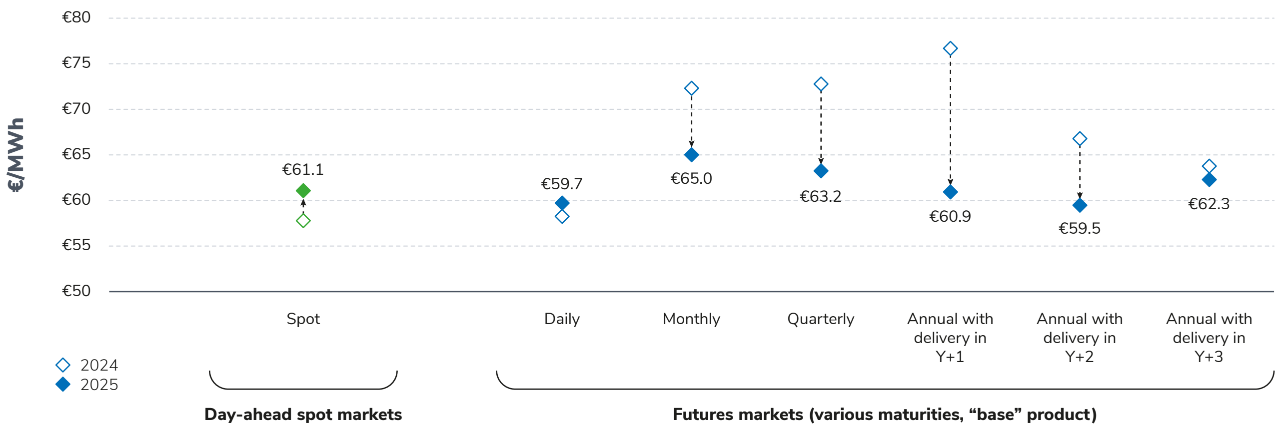
# Electricity prices

2025 ELECTRICITY REVIEW

## Spot electricity prices remained relatively stable in 2025, while futures prices fell and are now much lower in France than in most neighbouring countries

After two consecutive years of decline, **the average annual spot price of electricity in France remained relatively stable in 2025 compared with the previous year, reaching €61/MWh compared with €58/MWh in 2024.** This level is higher than the prices seen before 2020 (for example, the price was €39.4/MWh in 2019), but is still much lower than the prices reached between 2021 and 2023, at the height of the energy crisis (€275.9/MWh on average in 2022). In addition, spot prices have been increasingly volatile in recent years, which is reflected in the distortion of the average hourly price curve. On one hand, the morning and evening price peaks are now higher – mainly as a result of the higher price of gas (used by the power plants called on during peak periods) compared with the pre-pandemic period; on the other hand, the mid-day plateau has become a trough, as a result of lower consumption levels combined with the growth of solar generation in France and Europe.

**Figure 3.1 – Change in the average annual spot price and different average future price maturities for electricity in France between 2024 and 2025**




**Data source:** EPEX, Nord Pool, EEX Group

# France remained in a situation of abundant low-carbon generation, while fossil fuel prices rose slightly

The relative stability of spot prices reflects the stability of both gross electricity consumption and low-carbon generation compared with the previous year. As a result, the power system was still characterised by abundant low-carbon generation, as in 2024. This situation of "overcapacity" is likely to last for several years (see the analyses in the 2025 Generation Adequacy Report).

French gas-fired electricity generation fell by around 6%, and particularly generation by combustion turbines, which is more expensive than combined-cycle gas turbines (see Generation chapter). The price of gas rose by an annual average of around 5% compared with the previous year, reaching €35.8/MWh compared with €34.1/MWh in 2024. The gas price was at its highest in the first two months of the year (daily average of €40/MWh to €60/MWh between January and April), before following a downward trend to a low of €25.2/MWh at the end of November, one of the lowest levels in recent years.

It is also highly sensitive to the geopolitical context, which can lead to occasional price peaks. There were two of these in 2025: the first at the end of February 2025, when Russian gas transit through Ukraine was halted, and the second in June 2025, during the flash conflict between Israel and Iran. In addition, total French gas consumption[1] remained stable compared with the previous year and was still around 25% lower than pre-crisis (the voluntary target for a reduction in gas consumption set by the EU at the time of the energy crisis was 15% year-on-year[2]). French stocks remained within the historical range for most of the year, except in January and February, when a cold snap accelerated their use. However, the regulatory storage threshold (90%) was reached at the end of August, in line with the previous year.

The cost of $CO_2$ quotas, an element in the variable costs of generation by fossil-fired power stations, rose from an average of €66.4/t in 2024[3] to €74.4/t in 2025.

Overall, the rise in gas prices and $CO_2$ quotas had an influence on spot prices when they were set by gas-fired generation units, particularly at the beginning of the year; their influence on futures prices remained limited.

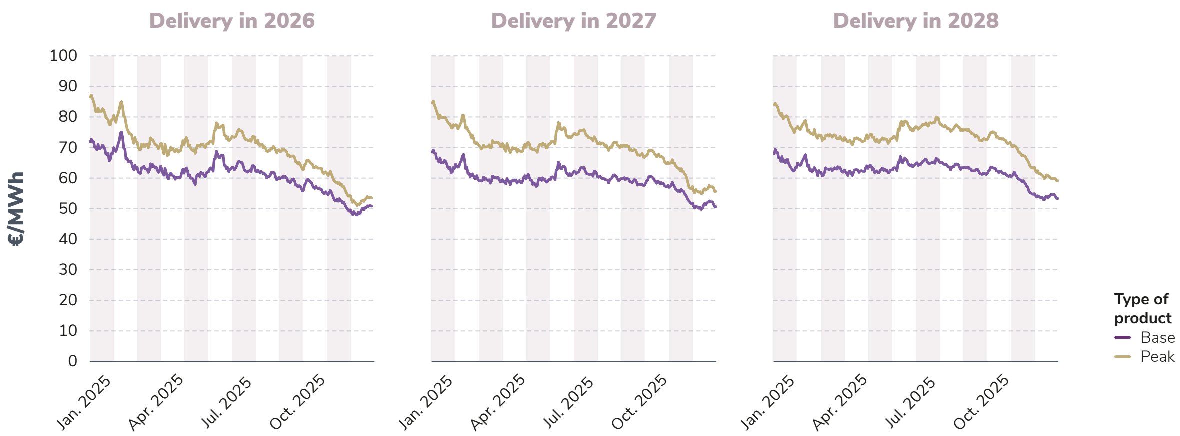
1. Data source: NaTran, RTE, Teréga – ODRE, *Consommation quotidienne brute*, November 2025
2. Toute l'Europe, *REPowerEU : comment l'Union européenne veut sortir de sa dépendance aux énergies fossiles russes*, December 2025
3. This is the average price for delivery in December, which is used as a reference for the quota price.

# Futures prices continued the decline that began in mid-2023 after the energy crisis

Prices for annual futures products traded in 2025 in France fell overall in comparison with the past. The price for delivery the following year dropped from €77/MWh in 2024 to €61/MWh in 2025 as an annual average. It trended downwards over the year and even broke through the €50/MWh barrier at the end of the year, something that had not happened since 2020.

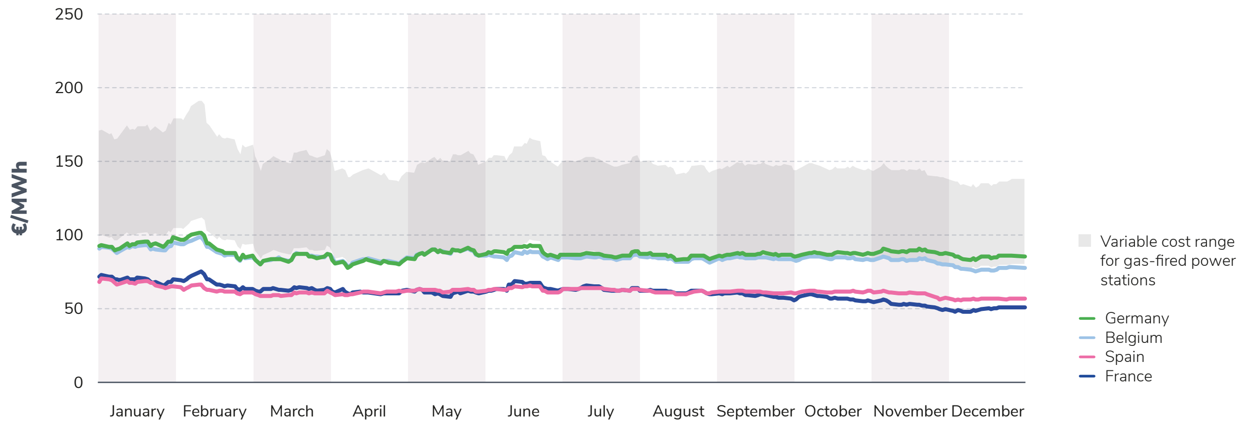
One notable difference between these two years concerns the relationship between futures prices for gas and electricity for delivery the following year. Between 2019 and mid-2024, the future price of electricity was within the range of variable costs for gas-fired power stations (dependent on gas prices, $CO_2$ quotas and power station yields). **Since the second half of 2024, annual futures prices in France**

**Figure 3.2 – Prices of annual calendar products traded in 2025, for different delivery dates**




**Data source:** EEX Group

**Figure 3.3 – Trends in electricity futures prices in 2025 for delivery in 2026 in several European countries in comparison with the variable costs of gas-fired generation units**




**Data source:** EEX Group. Calculations by RTE.

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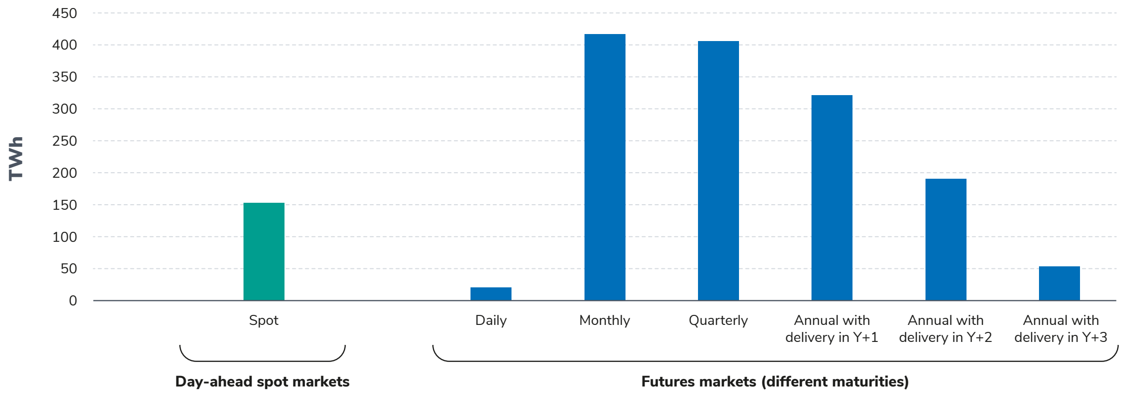
## Futures products account for the largest volume of electricity traded on the markets

Futures markets allow players to exchange electricity traded at various times before the moment of delivery, up to several years in advance. The products traded are generally of two types: ***base*** products, which correspond to a power band over 24 hours, every day, and ***peak*** products, which correspond to a power band during working days and only over the 8 am–8 pm window (when consumption is historically generally higher than at night). These products can cover several time scales. For example, the annual base product is a power band covering a whole year, while the quarterly peak product covers the 8 am–8 pm slots for the working days of the quarter in question.

**Futures markets enable buyers and sellers to control some of the financial risk:** in a theoretical situation where players traded only on the day-ahead market, they would be totally exposed to variations in the spot price, which is increasingly volatile (see the analysis of spot prices below). By carrying out a transaction several months or years in advance of the delivery date, players (energy producers, consumers who buy directly from the markets, traders, suppliers) can secure part of their supply or sales at a price negotiated in advance. Obviously, the further in advance of the delivery date the transaction takes place, the greater the uncertainty. For example, the prices of quarterly and annual products traded on the futures markets in 2022 and 2023 for delivery in 2025 were significantly higher than the prices resulting from auctions on the day-ahead spot markets in 2025, because some of these products were traded during the energy crisis of 2022–2023 and included a disproportionate risk premium (see the 2022 Electricity Review). The trade-off between different market maturities depends on each player's strategy and aversion to risk, and generally results in a mix of different maturities.

Figure 3.4 – Volumes traded on the spot market and for certain types of futures products in 2025




**Data source:** EPEX, Nord Pool, EEX Group

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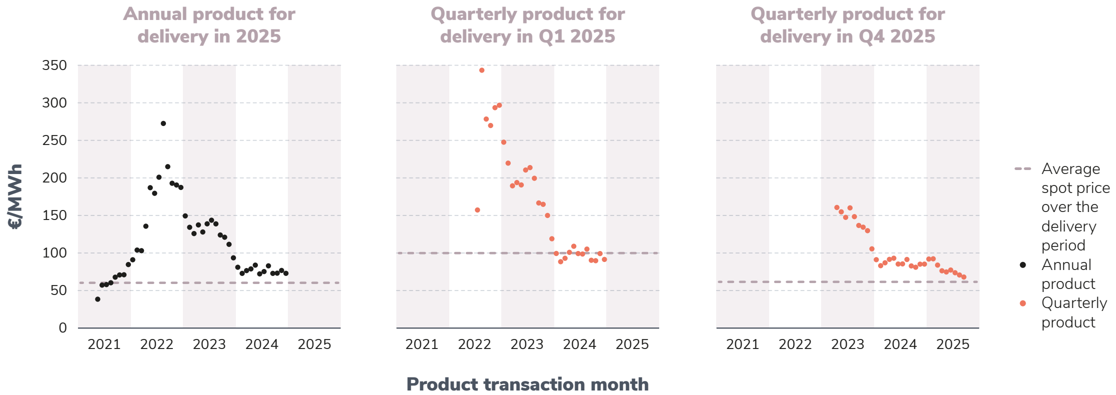
Futures products traded in 2025 represented 1,530 TWh[4], compared with 1,266 TWh the previous year. Monthly, quarterly and annual products for delivery over the following two years make up the vast majority of the volume traded, accounting for more than 1,300 TWh in 2025. In fact, the increase in the volume of these products, particularly monthly and annual products, accounts for almost all the change in volumes between 2024 and 2025: around 240 TWh more than the previous year (the volume remained stable for quarterly products). The increase in volumes traded on futures markets in 2025 is partly due to the upcoming expiry on 31 December 2025 of the ARENH scheme[5], which allowed alternative suppliers (excluding EDF) to purchase up to 100 TWh of electricity produced by EDF's legacy nuclear power plants at a regulated price (€42/MWh). This was the second year in which the 1,000 TWh mark was exceeded. By comparison, the volume traded on the day-ahead spot market was around 150 TWh in 2025, a level comparable to the previous year, but higher than in 2023 (122 TWh). **Due to the scale of the associated volumes in terms of supplies for suppliers and consumers, futures products are a decisive element in the pricing structure and thus in the bills paid by end consumers.** This is true for major consumers, who can buy large volumes of electricity on the futures markets, but also for smaller consumers, since these prices are used in the calculation of the "supply" component of the TRVE regulated tariff. By extension, futures prices play an important role in setting prices for all residential consumers, since the TRVEs constitute a benchmark for the various market players.

**Figure 3.5 – Average monthly "base" price of various futures products for delivery in 2025, by trade date**




**Data source:** EEX Group

4. EEX data totalling the volumes traded on the market and OTC – EEX, *Annual volumes 2025*, 13 September 2026
5. *"Liquidity on forward markets up to year Y+4 significantly increased with the end of the regulated access to historic nuclear electricity (ARENH) as of January 1, 2026."* – CRE, *The monitoring and functioning of wholesale electricity and natural gas markets in 2024*, July 2025

**have been persistently below the variable cost range for thermal power stations. They also fell below Spanish futures prices in the autumn (on average over the year, the difference was around €1/MWh in France's favour).** This is a sign that players expect prices in both countries to be often set by low-carbon generation, which is abundant in both generation mixes. In particular, prices in the two countries were several tens of euros lower than futures prices in Germany and Belgium. The latter are closer to the generation costs of fossil-fired power stations, while remaining at the lower end of the range.

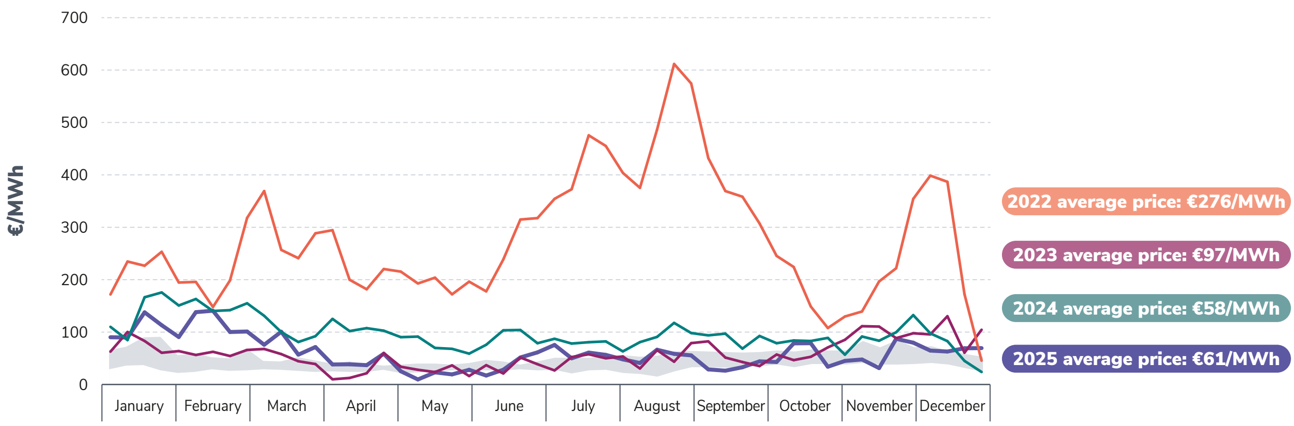
# Spot prices were relatively stable on average compared with the previous year, with wide variations over the year

**As a result of stable consumption and low-carbon generation, the average annual spot price remained relatively stable (+€2/MWh) compared with the previous year, reaching €61.1/MWh in 2025.** This stabilisation follows two years of substantial falls, driven by the recovery in French nuclear output and the drop in gas prices after the peak of the energy crisis in 2022–2023. The electricity spot price was still above the levels seen from 2002 to 2020 (€41.6/MWh on average [6]), but below the 2008 level (€69.2/MWh), which was affected by particularly high oil prices in the first half of the year.

**The year 2025 was marked by significant variations in spot prices from month to month, with much higher prices at the start of the year. The highest monthly average price (€122.7/MWh in February) was more than six times higher than the lowest monthly price (€19.4/MWh in May).** For comparison, the highest monthly price was around 2.2 times higher than the lowest before the pandemic (on average between 2002 and 2020). The 2025 ratio is the highest, ahead of the ratio in 2022, in the midst of the energy crisis (around 5.6).

**The highest monthly spot prices were recorded in January and February, when the average monthly spot price exceeded €100/MWh[7]** (€102.3/MWh in January and €122.7/MWh in February). This high price during the first two months of the year was due to low temperatures for the season, which led to high electricity consumption (a total of 3.1 TWh more than in January and February 2024), high gas prices in response to the stoppage of Russian gas flows transiting through Ukraine (+€22.4/MWh compared with the same months in 2024, an increase of almost 85%) and limited wind generation for a month of February (2.1 TWh lower in February 2025 than in February 2024).

**Figure 3.6 – Weekly average spot prices in France in 2025 and comparison with previous years**




**Data source:** EPEX, Nord Pool

6. In current values.
7. This price level has been the pattern for the winter months since 2021, but before that the highest average monthly price seen in a January or February was €82.3/MWh in February 2012, the month that saw the historic maximum consumption in France.

**The monthly spot price fell below the €20/MWh threshold during May 2025 (€19.4/MWh),** a threshold that had not been crossed since May 2020 under the effects of the pandemic. This fall in prices in May 2025 was driven by strong solar output (3.5 TWh, +0.8 TWh compared with May 2024) and wind generation (3.5 TWh, +0.9 TWh), with consumption similar to the same month the previous year (+1 TWh). This led to negative prices on multiple occasions, with a record number of monthly occurrences (133), closely followed by June (130).

# French prices decoupled from those in all the neighbouring countries on both the spot and futures markets in 2025

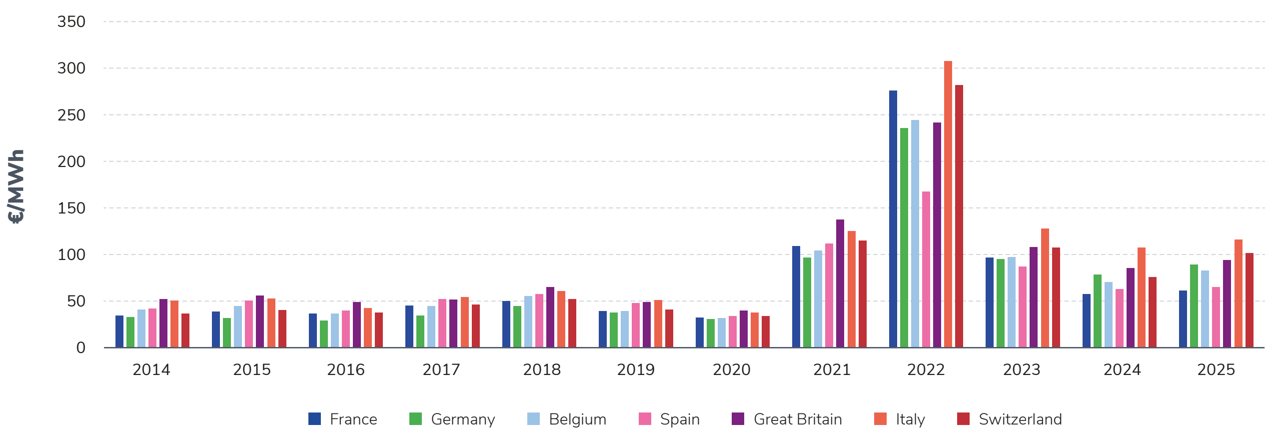
The French spot price was among the most competitive in Europe in 2025, behind the Nordic countries. It was in fourth place behind Norway, Finland and Sweden, whose electricity generation mix is almost entirely low-carbon, and was below the price in all neighbouring countries.

**Prices in France have largely decoupled from those in neighbouring countries. In particular, the price differentials are now between €20 and €50/MWh for Germany, Belgium, Great Britain, Switzerland and northern Italy.** The French spot price was lower than the German spot price for the second year in a row, which had not previously happened since 2011. The turnaround in the spread between the two countries can be explained structurally by changes in the German mix, with its last nuclear power station closing in 2023, but also by the recovery in the availability and output of the French nuclear fleet and by two years of unfavourable conditions for wind generation in Germany. **French prices also remained below Spanish prices for the second year running,** with a €4/MWh gap in France's favour (compared with €5/MWh in 2024). On a monthly basis, the sign of the spread between France and Spain, like the balance of trade, varied throughout the year according to changes in low-carbon generation and consumption on both sides of the border.

The fact that the price differential with Spain is lower is due to the high proportion of low-carbon generation in its mix, and therefore its lower dependence on fossil fuel prices compared with France's other neighbours. Historically, French prices were lower than Spanish prices, but strong growth in renewable energy in Spain, combined with the presence of nuclear power at around 20% of the mix, has made the Spanish mix more competitive with the French mix (see also the Europe and Trading chapters).

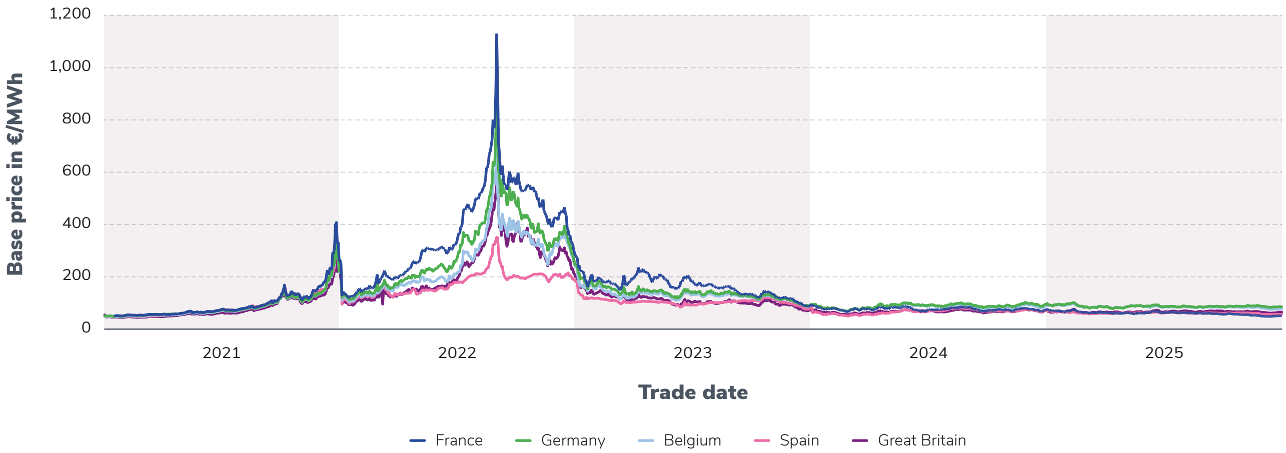
Spot electricity prices rose more sharply in other neighbouring countries, where the influence of fossil fuel prices is higher than in France: by around ten euros for Germany, Belgium, Great Britain and Italy, and by almost thirty euros for Switzerland.

**Figure 3.7 – Annual spot prices in several European countries**




**Data source:** EPEX, Nord Pool

Figure 3.8 – Futures prices for delivery in Y+1 in several European countries since 2021




**Data source:** EEX Group

**The competitiveness of the French mix can also be seen in annual futures products for delivery the following year. Only Spain has a similar average price level, but from September onwards the French future price fell even lower than the Spanish price.** This inversion between the two neighbours' futures prices marks a break with the period from the end of 2021 to mid-2024, when Spanish prices on the futures markets were more competitive than French prices.

The competitiveness of the French electricity mix reflects the abundance of low-carbon production at low variable cost in France, and constitutes a considerable asset for decarbonising the economy and accommodating new end uses (see the *Electrification* chapter and the 2025 *Generation Adequacy Report published by RTE in the autumn*).

# The hourly price profile is gradually being distorted by solar generation

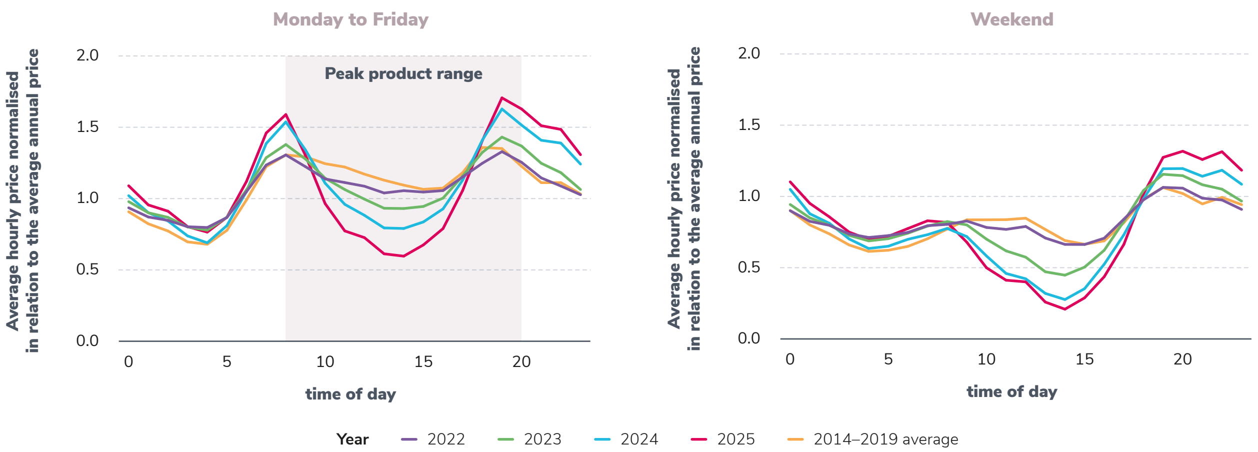
**The average hourly profile of spot prices over the course of the day has shown a fairly marked change since 2023, which has already been well documented by RTE in several recent publications.** Historically, the daily price profile showed a trough during the night, then a peak in the morning followed by a plateau in the middle of the day and finally another peak in the evening. There have been two main developments in recent years: on one hand, the morning and evening price peaks are now higher – mainly as a result of the higher price of gas compared with the pre-pandemic period; on the other hand, the mid-day plateau has become a trough, as a result of lower consumption levels combined with the growth of solar generation in France and Europe. This trough is even more marked at weekends, when consumption is structurally lower. With this distortion of the spot price curve, especially in spring and summer, the spot price is often lower during the day (8 am to 8 pm) than its daily average.

This gradual change to the spot price curve means “base” and “peak” products on the futures markets are also seeing their levels inverting relative to past trends. Between April and September 2025, the average spot price over the time steps corresponding to “base” products was higher than the price of “peak” products, which were initially intended to reflect periods of high consumption (and therefore higher prices). This inversion had already been seen between May and August 2024.

On the futures markets, the prices of monthly calendar products for delivery in July and August 2025 showed a similar inversion.

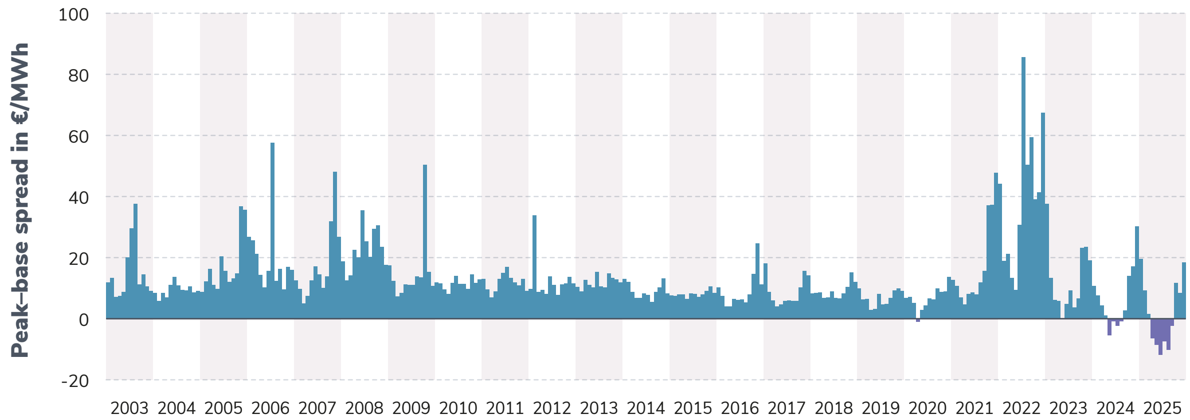
This change in the hourly profile highlights the importance of developing flexibility in the power system, in terms of both generation and consumption. In particular, shifting consumption to times of high low-carbon generation appears to be a valuable solution for optimising the balance and overall cost of the power system, limiting the modulation of renewable generation, minimising the need for thermal generation resources and, for consumers, reducing bills by optimising the positioning of their consumption during off-peak hours. In addition, regulatory changes have been introduced to encourage renewable generation to make a greater contribution to system flexibility (see Generation chapter).

**Figure 3.9 – Average profile of hourly prices, normalised in relation to the average annual price**




**Data source:** EPEX, Nord Pool

**Figure 3.10 – Monthly difference between average spot prices during “peak” periods (working days 8 am–8 pm) and during “base” periods (12 am–12 am every day)**




**Data source:** EPEX, Nord Pool

The spread of batteries (with around 13 GW on the waiting list, see *Generation* chapter) could also provide significant flexibility. Today, batteries mainly contribute to the provision of system services. In the medium term, the prospects for these storage facilities, particularly in terms of participation in the daily and intraday wholesale markets, will depend on the dynamics of consumption and production.

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## Switch to 15-minute intervals

On 1 October 2025, **the day-ahead spot price changed from an hourly interval to a 15-minute interval: instead of 24 hourly auctions, there are now 96 auctions (quarter-hourly delivery) that take place each day for the following day.** On 1 January 2025, the interval for settling imbalances (by balance responsible parties) had already followed a similar pattern, being reduced from 30 to 15 minutes.

These regulatory changes were motivated by the desire to encourage players to ensure the balance between generation and consumption within their perimeter at shorter intervals, but also to give players more scope for achieving this balance, in order to improve the management of the supply–demand balance the day before for the following day.

Initial analyses based on the last three months of 2025 (which are by their nature partial and relate to what was still a period of adaptation) show that the spot price curve is still broadly the same shape. The main notable change is that the curve now has a “sawtooth” profile within each hour, but with less variation compared with the daily amplitudes. Variability within each hour is greatest in the morning and evening, and lowest in the middle of the day and at night.

# Spot price volatility is much higher than before the crisis

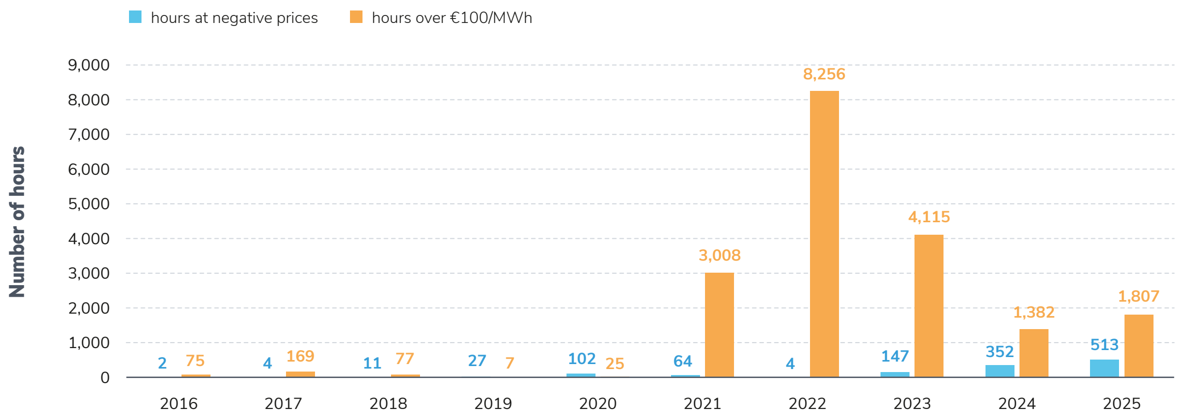
In recent years, the volatility of hourly spot prices has increased significantly compared with the years before the pandemic and the energy crisis, both in terms of standard deviation (€46.4/MWh in 2025 compared with €40.1/MWh in 2024 and €14.0/MWh in 2019) and average daily amplitude[8] (€89.7/MWh in 2025 compared with €76.4/MWh in 2024 and €27.2/MWh in 2019).

This increase in volatility is also clear when hourly prices are compared with historical price ranges: in 2025, hourly spot prices were above the 2014–2019 range over half the time, slightly more than in 2024 (52% compared with 48% respectively), and were below it around 25% of the time (compared with 21% in 2024).

The increase in the variability of spot prices can be explained partly by the "coexistence" of very high prices and low or even negative prices within the same day. More generally, the distribution of hourly prices has changed significantly over the last four years. From 2010 to 2019, spot prices remained within a fairly narrow range. In 2020, a few lower prices appeared at the height of the pandemic, without fundamentally changing the shape of the distribution.

Since 2021, prices have been spread out over a much wider range, firstly as a result of the energy crisis, which led to a large number of high prices at the end of 2021 and during 2022, and then with the increase in the number of very low or negative prices from 2023 onwards. As a result, there have been significantly more periods of negative prices or "high" prices since 2021. While the former appear mainly when low-carbon generation is very abundant compared with consumption levels (see the following section for a detailed analysis), the latter reflect the increase in the operating costs of gas-fired power stations relative to the years from 2010 to 2020.

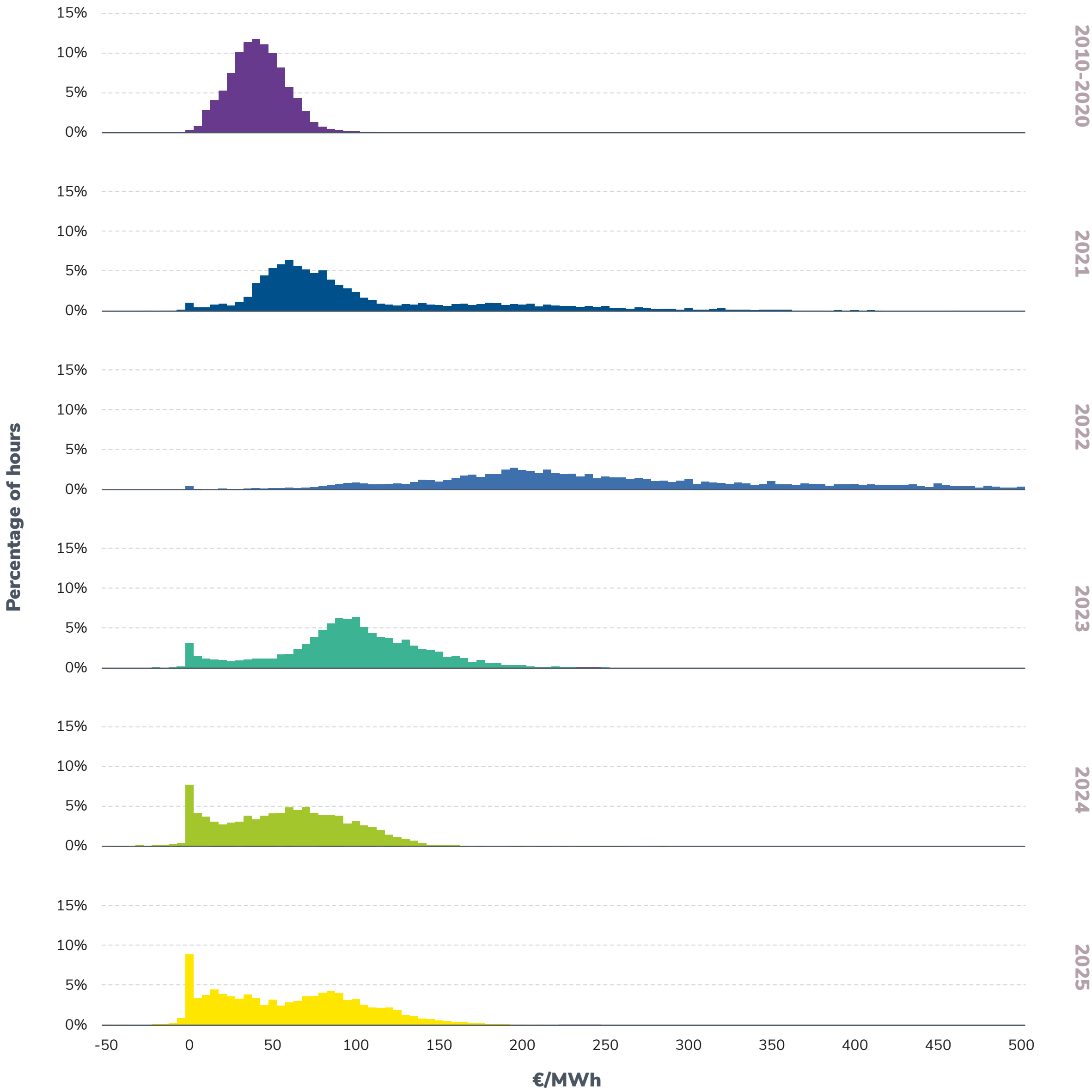
**Figure 3.11 – Number of hours with negative prices and hours over €100/MWh since 2010**




**Data source:** EPEX, Nord Pool. The number of negative prices in 2024 depends on the data source, as a technical incident caused EPEX SPOT to decouple for a few hours on 26 June. The value shown here for 2024 uses Nord Pool data for the duration of this incident.

8. The average daily amplitude is calculated as the average difference between the maximum price and the minimum price on each day.

**Figure 3.12 – Distribution of hourly spot prices from 2010 to 2025. Graph truncated at €500/MWh for legibility**




**Data source:** EPEX, Nord Pool

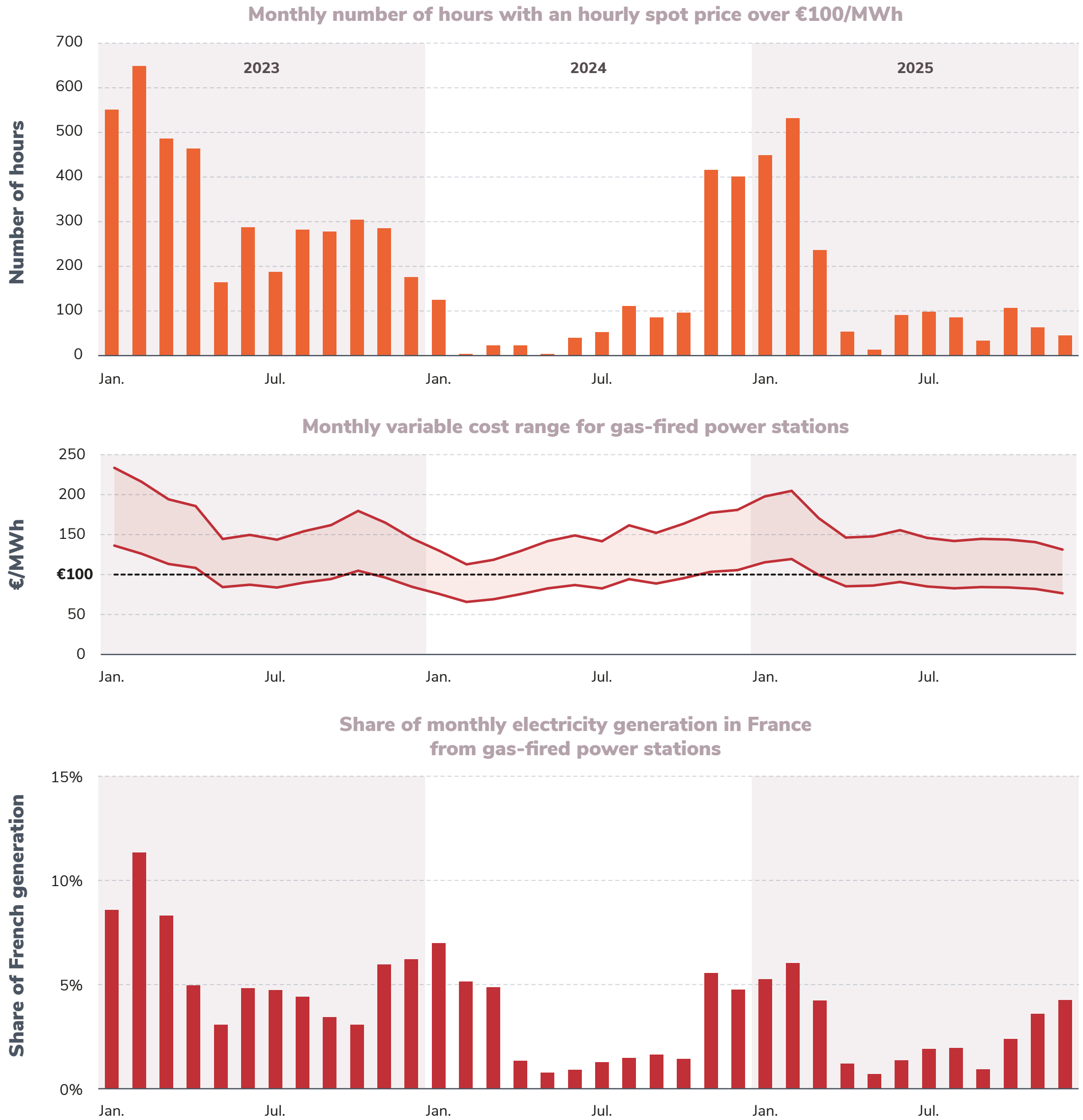
# The increase in the number of high-price hours reflects the rise in variable costs for gas-fired power stations

**In 2025, 1,807 hours exceeded the symbolic threshold of €100/MWh, compared with 1,382 in 2024.** These high-priced hours occurred mainly during the first quarter of 2025, when consumption was higher. This was when gas-fired power stations were used the most; gas prices were also relatively high at the beginning of the year, before starting to fall in the spring. In the first quarter of 2024, although gas-fired power stations were used in similar proportions to the first quarter of 2025, their operating costs were relatively lower because gas prices were at the bottom of the curve at the time, which meant that the number of hours when the price exceeded €100/MWh was lower in 2024. These high-price hours generally occur from Monday to Friday between 7 am and 10 am and then between 6 pm and 10 pm, at the opposite points of the cycle to the negative-price hours.

**The number of high-price hours has been higher in recent years than in the decade from 2010 to 2020: this reflects the higher operating costs of gas-fired power stations compared with the earlier period, rather than an increase in the use of these plants.** In fact, gas-fired generation in 2025 was around 16 TWh (approximately 3% of the mix), compared with an average of 28 TWh over the period from 2010 to 2020 (representing an average of 5.7% of the mix). For comparison, variable costs for gas-fired power stations ranged from €15/MWh to €100/MWh[9], depending on the month, between 2011 and 2020. In 2025, these variable costs ranged from €80/MWh to €230/MWh. Gas-fired power stations in France were used almost equally in March (2.2 TWh) and November 2025 (2.1 TWh), but the price of gas was considerably higher in March (€40.7/MWh) than in November (€29.5/MWh), which explains the significant difference in the number of hours when the price exceeded €100/MWh during these two months (236 in March compared with 63 in November). On the other hand, the proportion of the time when the hourly spot price exceeded the bottom of the range of variable costs for gas-fired generating units in France, an indicator of the proportion of the time when these generating facilities set the price, was similar for these two months (around 30% of the time). In addition, other generating resources may use the price of gas as a reference for setting their bids, particularly in the case of generating resources that depend on stocks, such as reservoir hydropower or batteries.

9. This interval concerns the variation in the average monthly variable cost, calculated on the basis of average monthly gas and $CO_2$ prices, with the assumption of an efficiency interval ranging from 35% to 60% and emissions of 0.204 tonnes of $CO_2$ per MWh of gas consumed.

**Figure 3.13 – Distribution of hours with spot prices over €100/MWh and comparison with the generating costs of gas-fired power stations and their share of the mix**

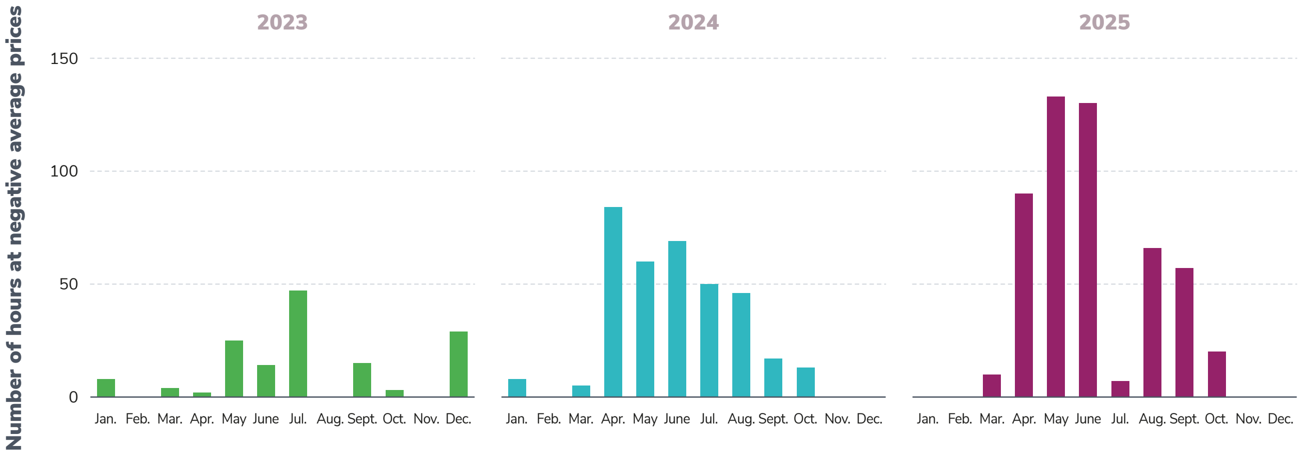



**Data source:** EPEX, Nord Pool. EEX Group, RTE

# Growing incidence of negative spot prices, with negative prices appearing more frequently during the week

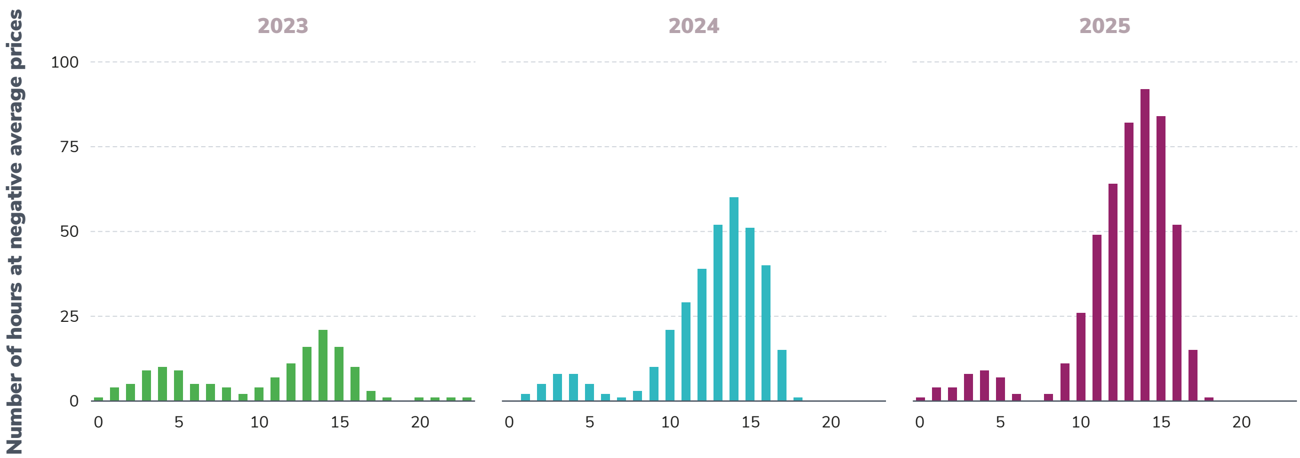
The hourly spot price was negative for 513 hours[10] in 2025, a higher number of occurrences than the previous year (352 in 2024), representing around 6% of the time over the year. The main change concerning negative prices is that they **appeared more frequently on weekdays (Monday to Friday) than in previous years:** 51% of hours with negative prices were recorded on weekdays in 2025, compared with 32% in 2024 and 27% in 2023. On the other hand, in line with previous years, negative prices mainly occurred in the middle of the day between April and August, i.e. when consumption is lowest and solar

**Figure 3.14 – Breakdown of negative prices recorded in France by month of the year**




**Data source:** EPEX, Nord Pool

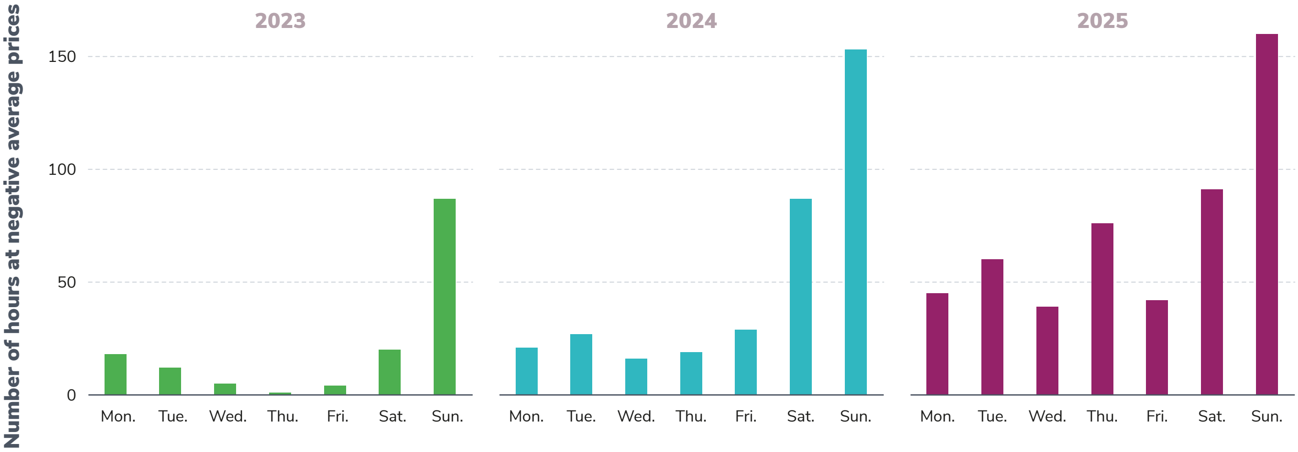
**Figure 3.15 – Breakdown of negative prices recorded in France by time of day**




**Data source:** EPEX, Nord Pool

10. After the switch to the 15-minute interval, an hour is considered to have a negative price if the average of the prices over the hour is negative, to maintain comparability with past records.

Figure 3.16 – Breakdown of negative prices recorded in France by day of the week




**Data source:** EPEX, Nord Pool

output is highest. **Nearly half the occurrences took place in May (133 hours) and June (130 hours).** The month of July 2025 was an exception in terms of the number of negative prices, since there were few occurrences in France (only seven) and in neighbouring countries due to an increase in residual consumption in France, Germany and Belgium.

# Negative prices were less negative than in 2024

**While the number of hours with negative prices rose sharply between 2024 and 2025, prices were less strongly negative on average.** The average negative price was €–6.5/MWh in 2025, compared with €–10/MWh in 2024 and €–6.8/MWh in 2023. These low absolute values mean that the electricity traded on the spot market during negative-price periods **represented less than 1% of the total value traded,** although these periods account for around 6% of the time.

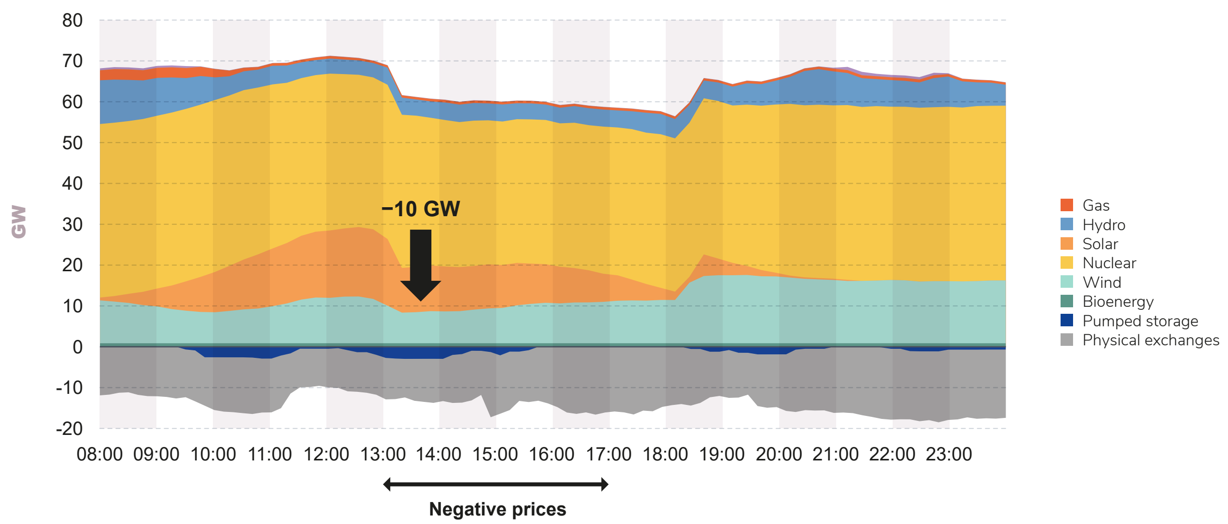
**Prices between €0 and €–0.1/MWh account for over half of the occurrences of negative-price hours** (55% in 2025 compared with 36% in 2024 and 54% in 2023). In other words, if the spot price had been €0.1/MWh higher over all the hours of the year, the number of negative prices would have been more than halved. Strongly negative prices were also much less frequent than in 2024, with prices below €10/MWh accounting for 14% of occurrences in 2025, compared with 31% the previous year.

# The consequences of negative prices arise from the operation of the power system and require its management to be adapted

Negative prices now occur in situations where consumption is low and low-carbon generation is plentiful. During these periods, renewable energy sources that benefit from the premium scheme have an economic incentive to stop generating.

These stoppages occur simultaneously when the negative-price period begins, resulting in a rapid fall in output whose precise scale is difficult to predict. During certain episodes when generation is significantly in excess of consumption, RTE is faced with

**Figure 3.17 – Illustration of the threshold effect of stopping renewable generation during an episode of negative prices on 1 April 2025**



very specific operating situations. This issue requires all the more care in terms of system operation in that information on the scheduling of shutdowns and restarts is often not transmitted to RTE. To meet this challenge, the scheduling system needs to be strengthened (by making programmes more reliable and updating them frequently) to anticipate this type of stoppage, and variations in output need to be controlled to ensure market players behave in a way that is consistent with the physical needs of the grid.

Methods for ensuring the operation of the power system during these trough periods are identified and grouped together in RTE's transformation plan for power system operation. RTE has already presented them to stakeholders in a detailed consultation programme. New legislative and regulatory provisions have recently been put in place to gradually increase the contribution of renewable energy sources to downward modulation and the balancing mechanism. The operational implementation of these new provisions now needs to be completed as quickly as possible and, more generally, the scheduling and operating rules need to continue to evolve in order to guarantee the balance of the power system over the coming years.

# Neighbouring countries are experiencing negative price episodes in similar proportions

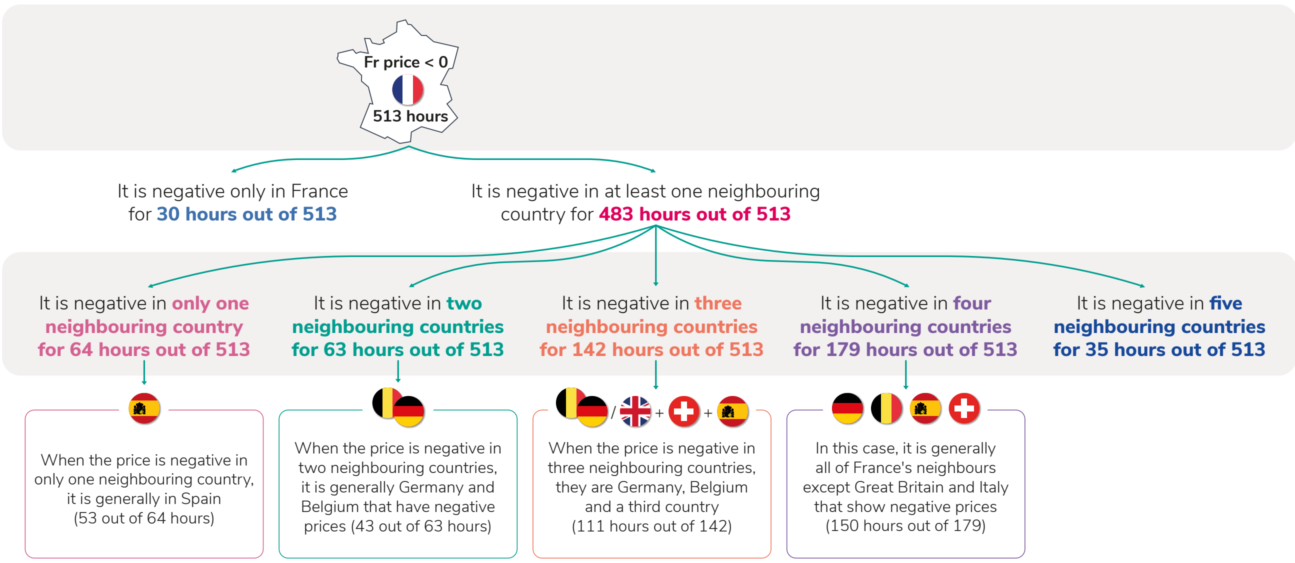
**In France's neighbouring countries, the number of negative prices was of the same order of magnitude as in France.** Germany recorded 576 hours at negative prices (457 in 2024) and Belgium 519 hours (404 in 2024). In Spain, which experienced its first negative prices in 2024, the number of negative-price hours more than doubled, rising from 247 to 556. Switzerland and Great Britain recorded 303 and 149 hours with negative average prices respectively.

**These negative-price episodes generally occur at the same time as in France.** As an illustration, situations where the French price is negative while all its neighbours' prices are positive or zero account for only 30 of the 513 occurrences of negative prices in France in 2025.

In general, the technical and economic fundamentals that lead to negative prices in France also apply in neighbouring countries. Moreover, the coupling of the European markets means that prices tend to converge between neighbouring countries if trading capacity allows. During these episodes, just as when prices are positive, electricity is exported from the country where the price is lowest to the one where it is highest. This lowers the equilibrium price in the importing country.

When the French price is negative, **France is a net exporter of electricity 90% of the time (460 of the 513 hours). However, it is often an importer across at least one of its borders (419 of the 460 hours)**, which means that in these situations, as for the rest of the year, it plays its role as an "electricity crossroads" due to its geographical location (see the Trading chapter) by importing electricity across one of its borders and re-exporting it across another. This situation, combined with the complexity of determining the marginal generation source (in France or abroad) setting the price, makes it difficult to identify unambiguously the origin of a negative price when electricity is being traded across borders.

**Figure 3.18 – Correspondence between negative prices in France and its neighbours**




**Data source:** EPEX, Nord Pool

It is important to note that a small increase in residual consumption can significantly reduce the number of instances of negative prices recorded, as was the case in July 2025. Once again, **France has a large amount of energy generated from competitive low-carbon sources, which is an asset in terms of the electrification of energy uses currently powered by fossil fuels.**

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## Why do negative prices happen?

Negative prices generally occur during times of low consumption combined with high renewable energy generation. During these periods, offers from producers can contribute to the formation of negative prices. Depending on the type of support mechanism involved, renewable energy producers may offer their output at a negative price in order to be selected. Dispatchable generating units may also formulate offers with negative prices, either because they prefer not to shut down their unit in order to save the associated technical costs, or because their operational planning requires them to respect a certain minimum level of production.

In addition, certain complex offers can also contribute to the appearance of negative prices. For example, a "block" offer is an offer to sell over several time intervals at a given price. If it is accepted, the seller is selected for the duration of the block, which reduces the volume remaining to be satisfied by shorter-interval bids[11]. In certain configurations, this mechanism can facilitate the appearance of negative price hours.

Negative prices are not in themselves an anomaly in the functioning of the market. In theory, the negative price is a legitimate economic signal, encouraging consumers to increase their consumption during periods of high renewable production, and producers with controllable units to lower their production levels. In fact, however, as only a small part of electricity consumption at a given time is covered by volumes traded at the spot price (or whose price is indexed to it), the incentive effect of this signal on the level of consumption is reduced.

In addition, a large part of renewable production is also not exposed to market prices, having direct power purchase agreements through the feed-in tariff mechanism. The negative price does not then act as an incentive to reduce this production. On the other hand, facilities on the premium scheme have an incentive not to produce if prices are negative. The mechanism does not provide for any remuneration for generation during these episodes, but it provides compensation if the total number of hours the facility is shut down over the year exceeds a threshold defined for each generation source.

11. This is a simplified explanation for information purposes. In practice, prices result from a process of joint optimisation over all the time intervals of the day, carried out by the market coupling algorithm.

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In a power system where the share of renewable energy is growing, negative prices are likely to occur more frequently, particularly if the electrification of energy uses is delayed and electricity consumption is slow to rise. The resources for dealing with these situations are clear:
- the flexibility of the generating fleet: the manoeuvrability of France's nuclear fleet is an essential source of flexibility;
- The development of support mechanisms for renewable energy: the premium scheme provides support for generating sources while encouraging modulation;
- The development of demand flexibility and storage. Generally speaking, certain uses of electricity (such as recharging electric vehicles or water heaters) could take place during the periods of the day most likely to experience negative prices, with no effect on user comfort and extremely competitive economic conditions for the consumer.

In this context, it is also worth recalling the usefulness of cross-border trade and the integration of European markets: the operation of the European electricity market enables optimum use to be made of the generating capacity available, within the limits of the trade capacities between the various countries. Trade makes it possible to take advantage of the variability of production and consumption profiles in different market areas, while minimising the cost of production on a European scale. In a purely theoretical situation in which there are no limits on trade in Europe, the price would be the same everywhere (negative or not), and all generation across the continent could be matched with all consumption in an optimised way.

In this hypothetical situation, negative prices would only be possible if the non-dispatchable renewable output of the whole of Europe were greater than the whole of Europe's consumption at a given moment. But total wind and solar power output is nowhere near the level of European consumption on an hour-by-hour basis. Over the last four years, as negative prices have multiplied, the average coverage rate has risen from 21% to 27%, and the maximum rate from 50% to 64%. This is purely theoretical, but it shows the advantages, in terms of managing the power system and minimising generating costs, of being able to "pool" generation and consumption across different countries via an interconnected power system and an integrated European electricity market.

# Electricity trading

2025 ELECTRICITY REVIEW

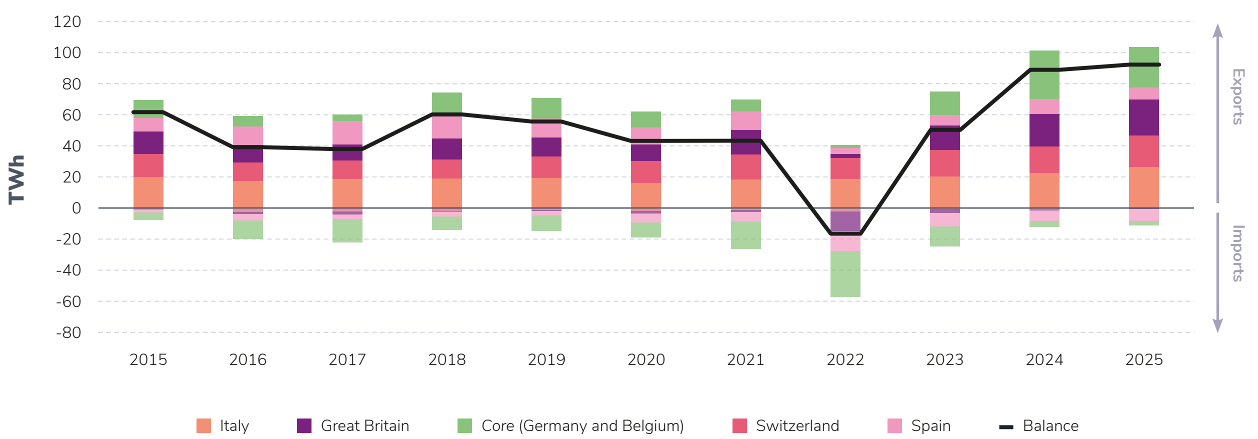
## The competitiveness of French generation led to a new export record in 2025, in line with the previous year

**France's net balance in 2025 was 92.3 TWh of exports. For the second year in a row, it was the highest since the beginning of trading between France and the other European countries,** exceeding the 2024 export balance (89.0 TWh), in a generally similar context. For comparison, this represents a volume similar to the total electricity consumption of a country such as Belgium (around 80 TWh in 2025).

**The balance of trade was very positive across all borders except to Spain, where trade was more balanced.** It amounted to 22.6 TWh with Great Britain, 20.1 TWh with Switzerland, 26.2 TWh with Italy, 23.1 TWh with the Core region, i.e. the borders with Germany and Belgium, and 0.2 TWh with Spain.

**This export volume reflects fundamentals that have changed little since 2024. National electricity generation remained high in 2025, and essentially comprised a highly competitive (low-variable-cost), low-carbon production base.**

**Figure 4.1 – Annual electricity trading between France and its neighbours between 2015 and 2025**



The drop in hydropower production was offset by the return of nuclear power to pre-pandemic levels, as well as the increase in solar power output due to growth in the installed base and favourable sunshine conditions.

**In addition, consumption remained stable compared with 2024, and is still below pre-crisis levels** (see the *Consumption* chapter). Finally, the large export balances of 2024 and 2025 were enabled by the development of interconnections and the growing integration of Europe's electricity markets.

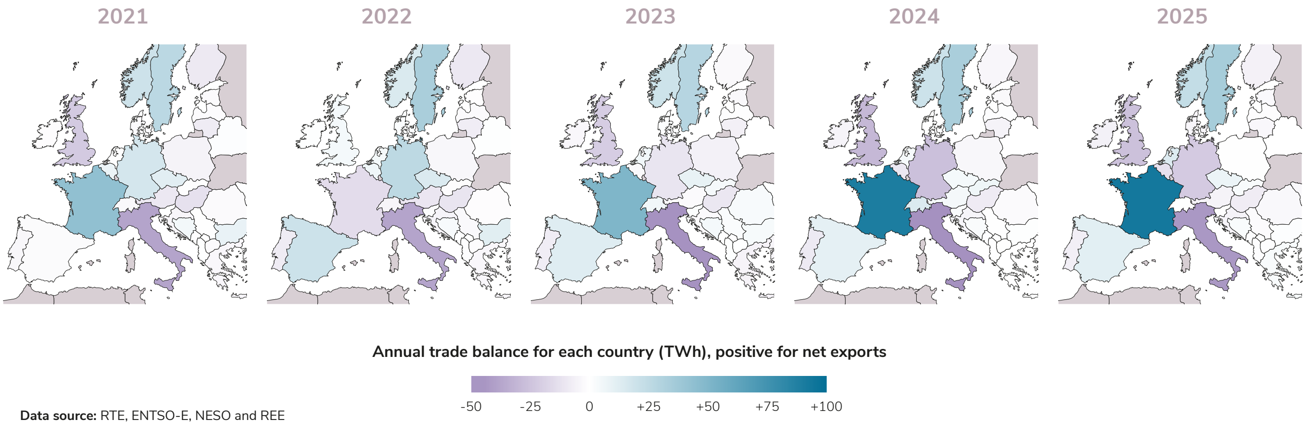
**These trends confirm the diagnosis of the recent 2025 Generation Adequacy Report: the abundance of French low-carbon electricity generation puts the country in a very favourable position to decarbonise quickly and reduce its dependence on fossil fuels, which still account for almost 60% of its total energy consumption.**

**France remained Europe's leading net exporter of electricity by volume, as it has been almost every year for the past three decades**[1] (excluding 2016, 2017[2] and 2022). **France exported the equivalent of 17% of its output in 2025,** similar to the 2024 level (16.5%). France is not the only country to export such a high proportion of the electricity it generates: some northern European countries such as Norway and Sweden also have high export rates – around 22% for Sweden in 2025 – thanks to their large renewable generation capacity, mainly hydropower and wind. Conversely, other countries such as Italy, Portugal and Great Britain[3] rely heavily on imports to cover their electricity consumption, in proportions of up to 15–20%.

**Comparable proportions of exports had previously been achieved in France between 1992 and 2002,** when they oscillated between 12% and 15% of national production. This was a time when the nuclear fleet had grown strongly and consumption was at lower levels than today (see the Focus on the historical view of French power trading).

**At the monthly level, the export balance remained strongly positive in every month of 2025,** extending the trend observed since mid-2023. Values were slightly lower in the first half-year than in the second, driven by consumption and by higher prices at the beginning of the year.

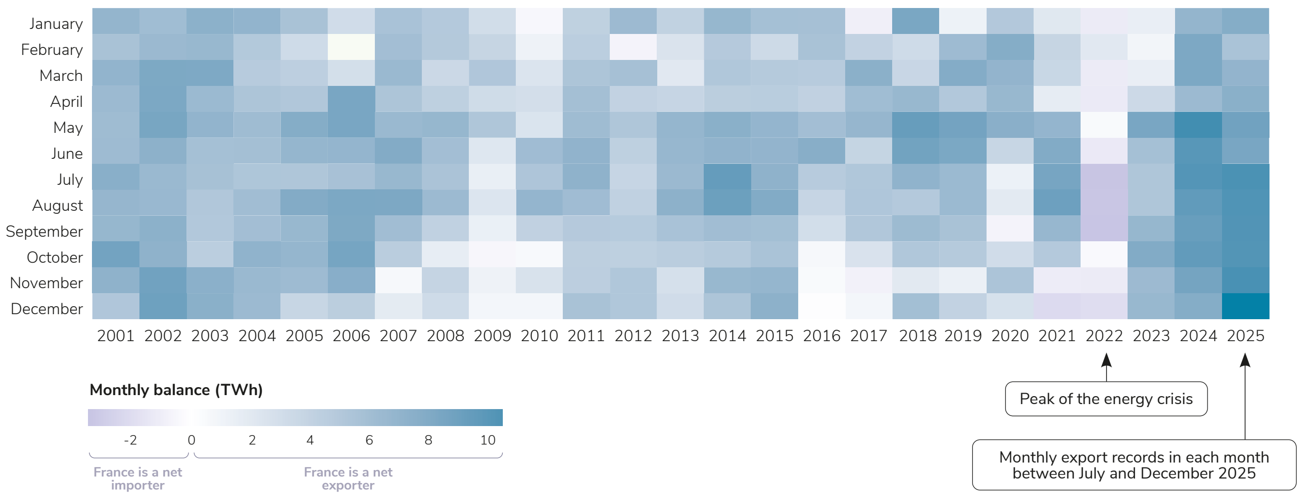
**Figure 4.2 – Annual balance of trade in Europe between 2021 and 2025**




**Data source:** RTE, ENTSO-E, NESO and REE

1. The Eurostat data used to calculate the balance for each European country only goes back to 1990.
2. France was Europe's second largest exporter in those years, behind Germany.
3. In analysing trade, we consider Great Britain rather than the whole United Kingdom, as Northern Ireland is part of the integrated Ireland/Northern Ireland market area (see the Focus on the details of trade with Great Britain).

Figure 4.3 – France's monthly electricity trade balance since 2001




Historically high levels of exports were recorded from July until the end of the year, driven by particularly significant trade with Great Britain, Italy, Germany and Belgium. Over this period, consumption remained virtually unchanged from the previous year (+0.1 TWh per month on average). At the same time, low-carbon generation increased overall: +1.2 TWh per month on average for nuclear, +0.8 TWh for wind, +0.7 TWh for solar. Only hydropower output fell, by an average of –1 TWh per month. December saw a new monthly export record, reaching 10.5 TWh. During this month, nuclear generation reached a level not seen since January 2019.

## FOCUS

### Electricity markets aim to optimise the use of the resources available

The power systems of the different European countries are now widely interconnected. Most countries in continental Europe are part of the synchronous continental power system, which shares the same 50 Hz electrical frequency at all times.

By making it possible to take advantage of the synergies between national energy mixes, the interconnection of the power systems benefits the European community in three ways: by reinforcing the security of the electricity supply and operational security, by reducing production costs on a continental scale through the use of the least expensive production resources, and by making it possible to integrate greater volumes of decarbonised energy.

**Trade between European countries means that the least expensive (and therefore often least carbon-intensive) generating capacity available can be called on at any given time to cover electricity consumption**

FOCUS

**in Europe, even in high-pressure situations.** This possibility proved essential when supply to the French power system came under pressure in the autumn and winter of 2022/2023. As a general rule, the integration of the European power system is particularly beneficial in making it possible to take advantage of the varied consumption profiles in different countries. For example, consumption peaks do not occur at the same time of day or in the same season in different countries – they happen on summer afternoons in Italy, on winter evenings in France and on winter mornings in the Scandinavian countries. To a lesser extent, pooling also enables full advantage to be taken of the different production profiles of variable renewable energy.

Over the past fifteen years, the strengthening of interconnections between countries and the development of variable renewable energy have led to a significant increase in electricity trading between European countries, and France is at the heart of this trading. **Located at the intersection of several electrical peninsulas (Iberian peninsula, Italy, Great Britain) and with significant installed generating capacity, France participates fully in European trade.** France's energy mix, made up mainly of low-carbon generation sources (nuclear, hydropower and other renewables), is on the whole more competitive than that of most of its neighbours. As a general rule therefore, in the absence of pressures on the national supply–demand balance, the power system is a significant exporter across the scale of a year: supply from French nuclear and renewable generating capacity is called on by the markets before thermal production units, including those in neighbouring countries (within the limits allowed by interconnection capacity). At other times, even in non-crisis situations, it is normal for the country to be a net importer from time to time, for a few hours or a few days: this is typically the case when it is cheaper to import than to generate additional volumes in France. This happens, for example, when there is high renewable generation in neighbouring countries, particularly Spain or Germany (see the details for each border below).

France's interconnection with other European countries, and its full integration into the market mechanisms governing trade, mean that it can:

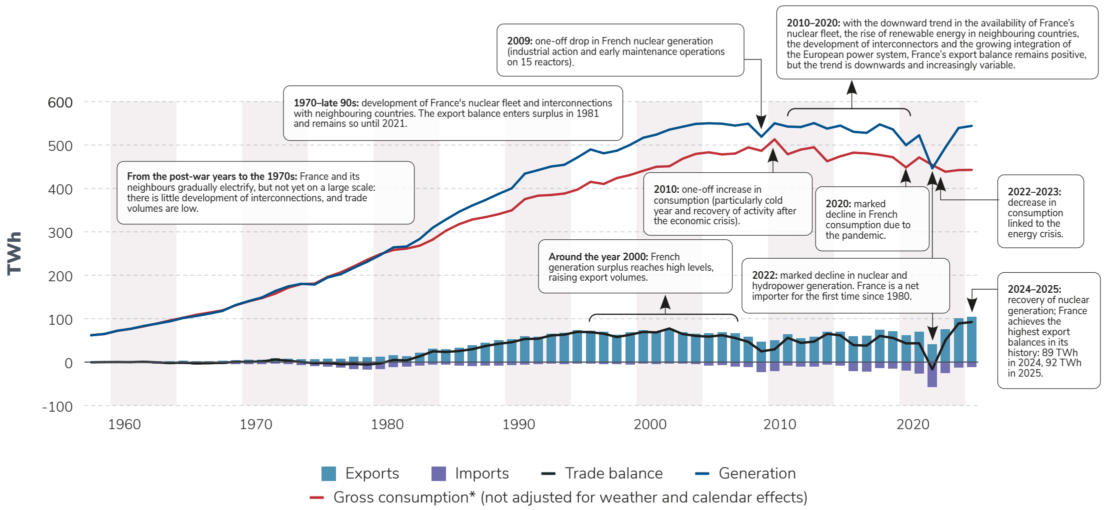
- find economic outlets for its low-carbon generation and contribute to decarbonising the European mix on one hand;
- ensure its security of supply at a much lower cost than if the country had to rely solely on national generation resources at all times, on the other.

By 2030, RTE will have completed work on the two DC connection projects currently under way with Spain and Ireland. In addition to these projects, work is planned on the existing network at the Spanish, Belgian and German borders, which will also increase trading capacity. However, additional projects can only be decided on if the physical situation of the French network, located at a European electricity crossroads, is taken into account. In 2025, a very small proportion (2%) of France's imports supplied French consumption; the rest were flows imported from one border to be re-exported to other borders (see the analysis later in the chapter). These flows have an impact on the domestic power grid, as highlighted in the Ten-Year Network Development Plan (SDDR 2025). The development of new interconnections will thus depend on the acceleration of measures to strengthen the French domestic grid, which will involve greater financing requirements than the SDDR's reference pathway for the period between now and 2035.

FOCUS

## A historical overview of French electricity trading

**Figure 4.4 – Electricity generation, consumption and trade between 1955 and 2025**




* Gross consumption excludes PSH, which has represented 6 to 8 TWh per year over the last decade.

**Before 1945, electricity played a relatively minor role in the country's energy system.** The first power stations in France, built at the end of the 19th century, were either hydroelectric or coal-fired. Electricity became widely used over the first half of the 20th century, particularly for lighting, but there was still no unified transmission grid, and generating facilities were mostly private, for industrial use. The bulk of electricity generation came from coal and hydropower.

**From the post-war period until the end of the 1970s,** electricity consumption increased significantly (+1% per year on average), against a backdrop of strong economic growth and the electrification of the country. The first interconnection between the French, Swiss and German networks was created in 1958.

**Following the first oil crisis in 1973,** France rapidly developed a large fleet of nuclear reactors to reduce its dependence on fossil fuels. During this period, 48 nuclear reactors were commissioned between 1978 and 1989[4]. At the same time, the development of electrification was encouraged, particularly by incentivising the installation of electric heating and water heaters. However, under the combined effect of energy-saving policies, slower economic growth and the oil crisis of 1986, which led to sustained low fossil fuel prices until the end of the 1990s, electricity consumption did not grow as fast as projected, leading to a structural surplus of electricity generation in France, which could then be exported.

**As a result, France's trade balance recorded a surplus from 1981, and exceeded**

4. Assemblée Nationale - Office parlementaire d'évaluation des choix scientifiques et technologiques, *Rapport sur l'aval du cycle nucléaire - Les coûts de production de l'électricité*, February 1999

## FOCUS

**60 TWh from 1993,** supported by the growing interconnection of electricity grids and the competitiveness of France's nuclear fleet. A local peak was reached in 2002, with an export balance of 76 TWh. The last second-generation nuclear reactor was commissioned in the same year.

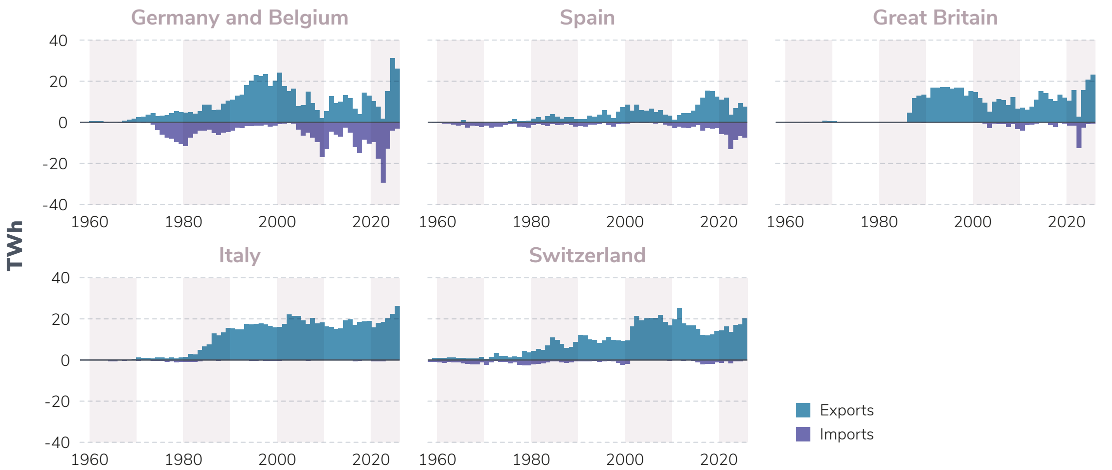
**During the 2000s,** electricity consumption continued to increase. At the same time, generation levelled off from the middle of the decade, partly due to the lack of new nuclear projects coming on stream and the absence of any marked drive to develop the renewable fleet.

**From the late 2000s and during the 2010s,** the availability of the French nuclear fleet declined as maintenance operations became more intensive due to the ageing of the plants and the launch of the "Grand carénage" refurbishment programme. The Fessenheim power station shut down permanently in 2020. In parallel, renewable energy, and particularly wind and solar power, expanded in France and Europe. France's trade balance remained positive, even though the proportion of generation destined for export no longer reached the unusually high levels seen in the early 2000s.

**After a marked decrease during the energy crisis in 2022 (when France became an importer), the country's balance broke its 2002 export record (76 TWh) two years in a row in 2024 and 2025,** with 89 TWh and then 92 TWh respectively, driven by strong low-carbon generation (thanks partly to the recovery in nuclear availability) and consumption that was lower than in the 2010s.

**As a result, the French power system is currently experiencing a situation of national electricity abundance, though this is not unprecedented.** In the electricity industry, cycles occur regularly because of the contrast in time scales between the inertia associated with developing generation and network infrastructure, which extends over several years or even decades, on one hand and the occurrence of energy and economic crises or major shifts in consumption, which happen over much shorter periods of time, on the other. This can lead to periods, such as the current one, when the growth dynamic of electricity generation is temporarily out of sync with growth in consumption.

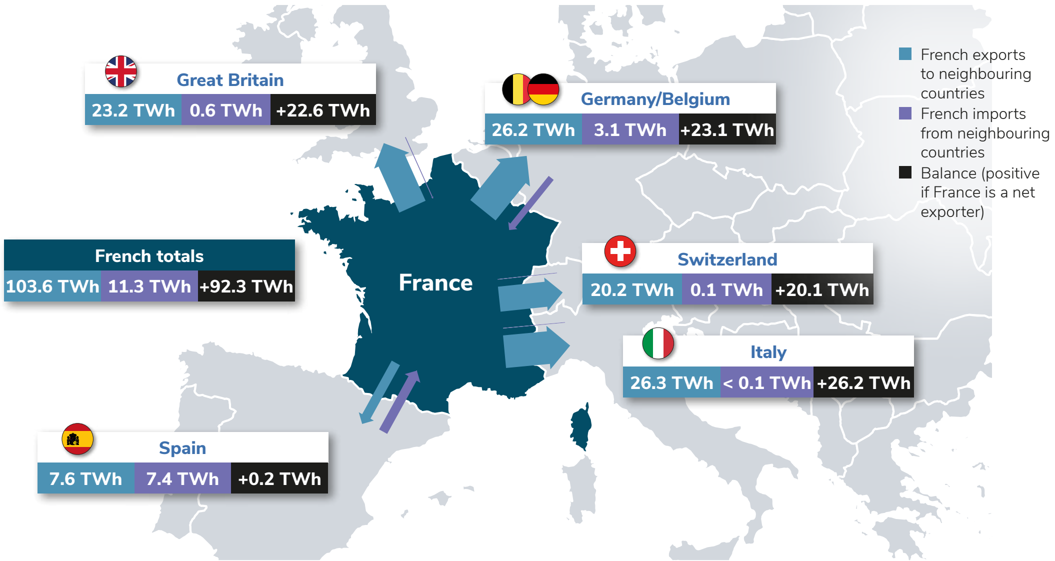
**Figure 4.5 – Volumes traded* by border since 1958**




* Physical volumes before 2001, commercial volumes after 2001

# Trade with neighbouring countries: contrasting trends at different borders

**Figure 4.6 – Electricity trading between France and neighbouring countries in 2025**




Although the net balance of electricity trading in 2025 was close to that of the previous year, the trends varied slightly from one border to another.

The balance of exports increased in relation to Great Britain (22.6 TWh, i.e. +2.5 TWh compared with 2024) and Italy (26.2 TWh, i.e. +3.9 TWh compared with 2024), mainly due to better availability of exchange capacity with these two regions. The balance also increased in relation to Switzerland (20.1 TWh, i.e. +3.5 TWh), where a nuclear power station has been shut down for technical reasons since May 2025[5]. However, it fell with Spain (0.2 TWh, or −2.6 TWh), mainly as a result of significant imports from this region at the beginning of the year, when French consumption was at its highest, and with the Core region, i.e. the borders with Germany and Belgium (23.1 TWh, or −4.1 TWh), mainly due to maintenance work on the interconnection lines across these borders in the spring and summer of 2025.

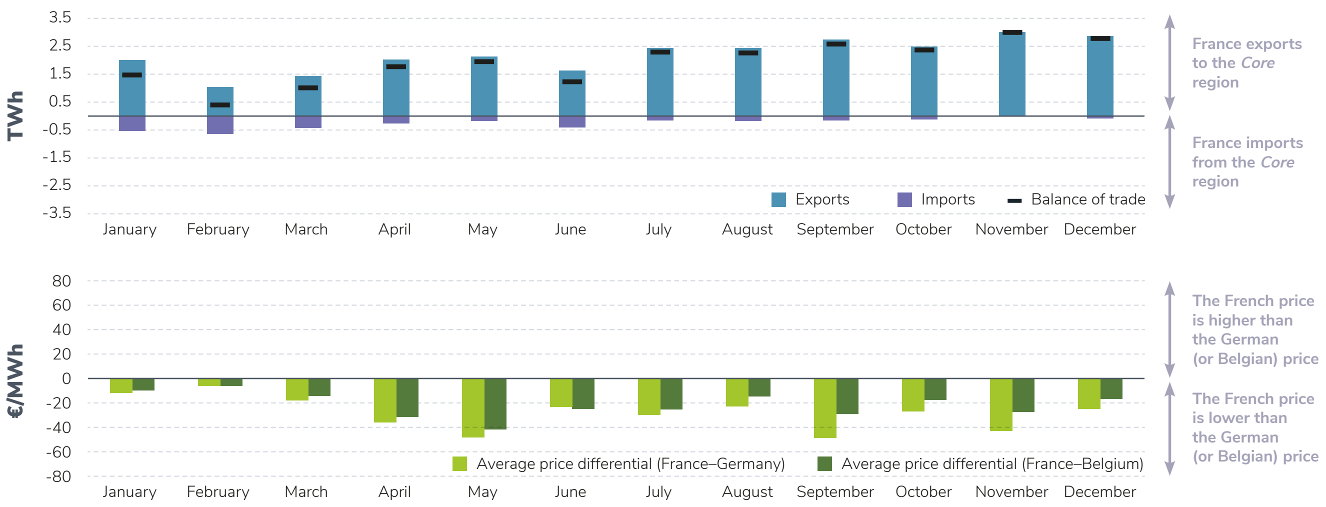
5. It is worth noting that a significant proportion of exports to Switzerland are re-exported to Italy – see the “Flow tracing” section.

# France exported a high volume to the Core region, but less than in 2024

**The balance of trade between France and its neighbours in the Core *region*, i.e. Germany and Belgium, was 23.1 TWh in exports. This is the second highest export balance ever recorded across this border, behind 2024 (27.2 TWh) and ahead of 2001 (17.1 TWh).** The balance was 4.1 TWh lower than the previous year due to the drop in the volume exported from France to Germany and Belgium (from 31.3 TWh in 2024 to 26.2 TWh in 2025), which was not offset by the drop in the volume imported (from 4.1 to 3.1 TWh). The reduction in volume of trade is mainly due to major maintenance work on the Franco-Belgian interconnections during 2025. The export balance was exceptionally strong at the end of the year (whereas France has generally been a net importer from Core during this period) due to particularly low renewable generation in Germany and high low-carbon generation in France.

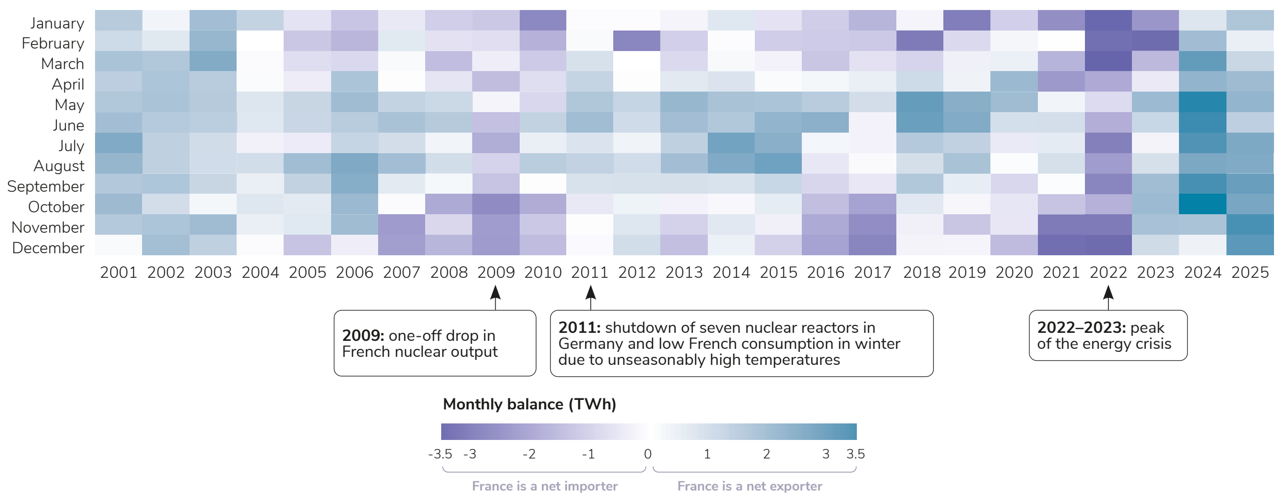
The total volumes traded with the Core region (absolute value of imports plus exports) were the highest; exchange capacity is also higher than across the other borders[6]. Historically, trade with this region has been highly variable, depending on the period or the year: this is due to market integration, but also to the significant change in the generation mix in the region over time, including an increasingly high proportion of low-carbon generation, particularly wind and solar. **As of the end of 2025, more than 115 GW of solar power was installed in Germany and Belgium. The effect of solar generation is particularly visible: France was a net importer from the Core region in the middle of the day (12 pm–2pm) on almost 40% of days in 2025,** whereas this figure falls to an average of 7% from 5 pm to 8 am.

**Figure 4.7 – Monthly volumes of electricity trading between France and the Core region member countries (top) and average monthly differences between French spot prices and spot prices in these countries (bottom) in 2025**




6. In addition, the border with the Core region is the only French border on which exchange capacity is determined on the basis of a so-called “flow-based” approach, which optimises the use of exchange capacity.

**Figure 4.8 – Monthly trade balances between France and the Core region since 2001**




**Prior to 2022, France exported to the Core region during the summer, when French consumption is lower, and imported from the Core region during the winter. This pattern has changed since 2023: the export balance from France to the Core region has been positive every month since May 2023.** The annual balance of trade between Germany and its neighbours has tilted towards imports since 2023 (28 TWh of imports in 2024, 22 TWh in 2025), with the nuclear phase-out completed at the beginning of 2023 and the gradual closure of coal-fired power stations (scheduled for complete shutdown by 2038 at the latest). A similar trend is occurring in Belgium, in a similar context of nuclear power plant shut-downs[7]. French exports to Germany and Belgium also contribute to consumption beyond these two countries, which accounts for 30% of the 26 TWh exported, particularly to other Central European countries (see the analysis of flows exported beyond neighbouring countries later in this chapter).

7. Of Belgium's seven nuclear reactors, two were shut down in 2022–2023, and three in 2025. It should be noted, however, that in March 2025 the Belgian parliament repealed the 2003 law on nuclear phase-out, thereby removing any reference to the end of nuclear in 2025, as well as the ban on Belgium building new nuclear generating capacity.

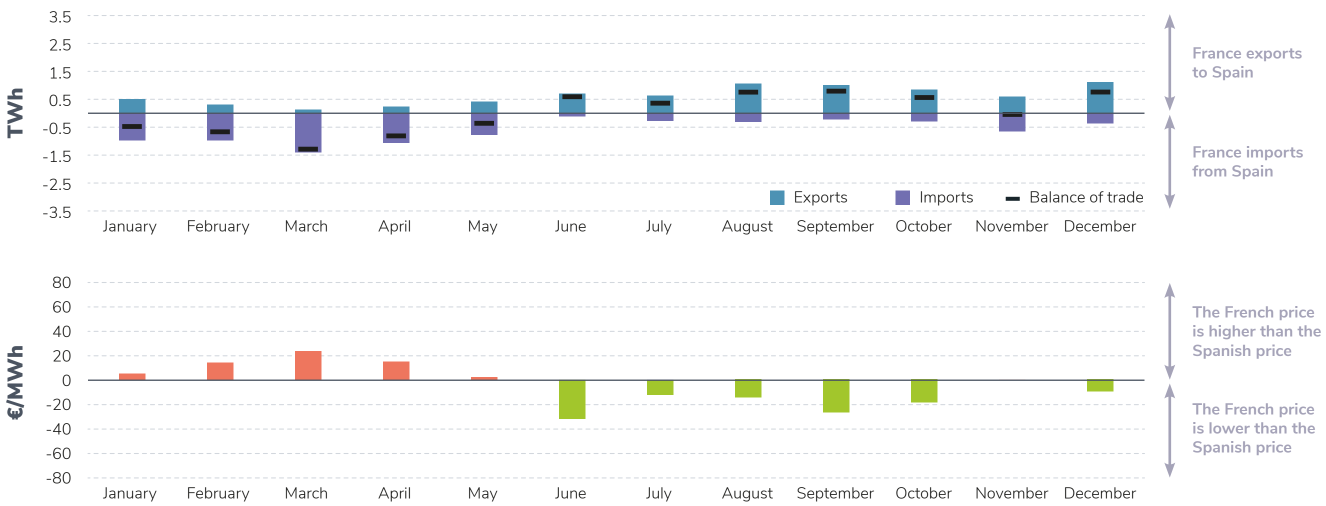
# Trade with Spain remained balanced

**France's net trade with Spain was close to being balanced in 2025, amounting to 0.2 TWh** (7.6 TWh of exports and 7.4 TWh of imports).

Until 2022, France was generally an exporter to Spain; since the energy crisis in 2022, when France exceptionally became a net importer across this border, trade has been more balanced, being slightly negative in 2023 and slightly positive in 2024 and 2025. **This results from the increased competitiveness of the Spanish generation mix, with its low-carbon share (nuclear and renewable) rising from an average of 66% over the 2015–2019 period to an average of 78% between 2023 and 2025.** Spanish wind production in particular has influenced the direction of trade[8]. It should also be noted that most of France's exports to Spain are re-exported by Spain at the same time to Portugal and Morocco (see analysis below).

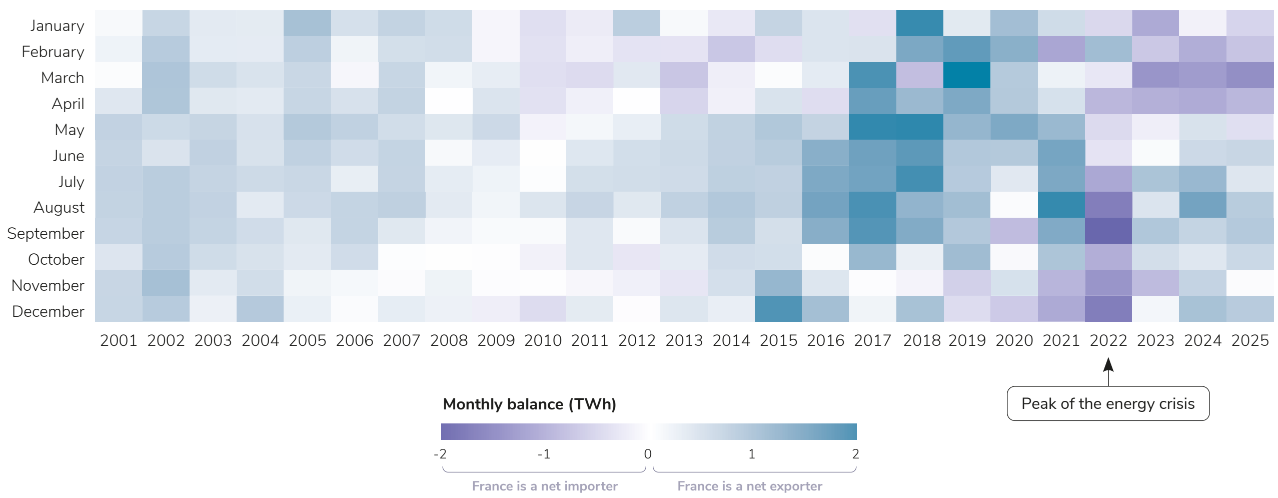
The average price in Spain was €66/MWh in 2025, compared with €61/MWh in France. This is the lowest price among France's neighbours. Spain was the only country where the average monthly spot price was lower than the French price; this was the case from January to May, and again in November. Between January and May, therefore, trade was mainly from Spain to France. From June onwards, the direction of trade reversed, as consumption fell in France at the end of the heating period and increased in Spain with the rise in air conditioning (+18% in July compared with May), and French nuclear availability remained relatively high for the season. The export balance turned slightly negative in November, before becoming mainly positive again in December.

**Figure 4.9 – Monthly volumes of electricity trading between France and Spain (top) and monthly average differences between French and Spanish spot prices (bottom) in 2025**



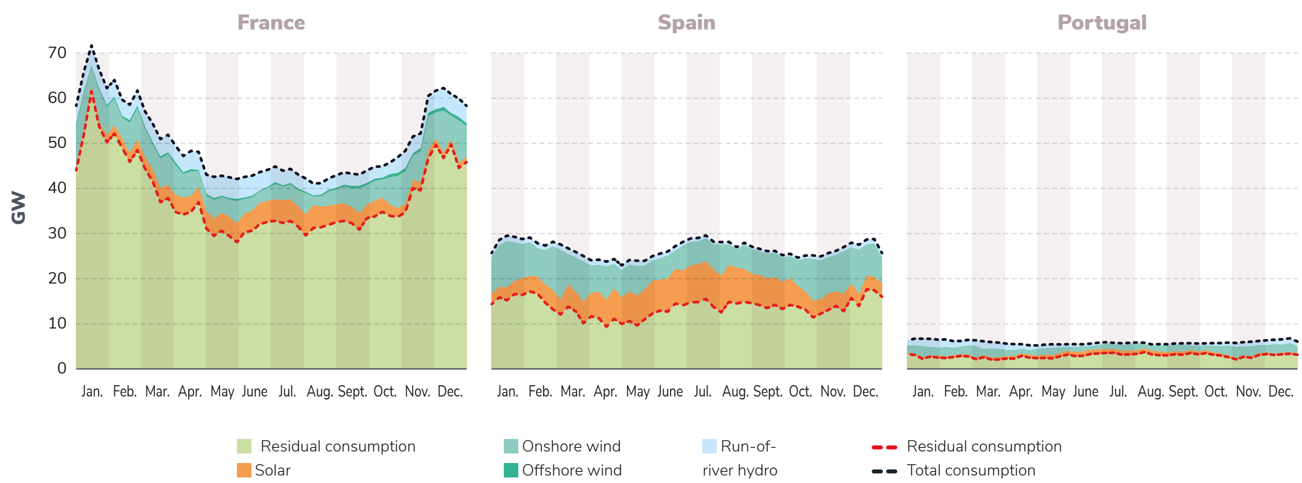

8. View detailed analysis: RTE, 2024 *Electricity Review – Trading chapter – details for each border*, February 2024

**Figure 4.10 – Monthly trade balances between France and Spain since 2001**




It is interesting to compare trade trends with the consumption profiles in France, Spain and even Portugal. Consumption on the Iberian peninsula has a "flatter" profile over the year than in France, although it is slightly higher in winter and early summer – the temperature sensitivity of consumption is lower there than in France (see Europe chapter). As a result, France often imports from Spain in winter and exports to Spain in summer.

**Figure 4.11 – Weekly residual consumption in the Iberian peninsula and France over the year (averages over the period 2023–2025)**



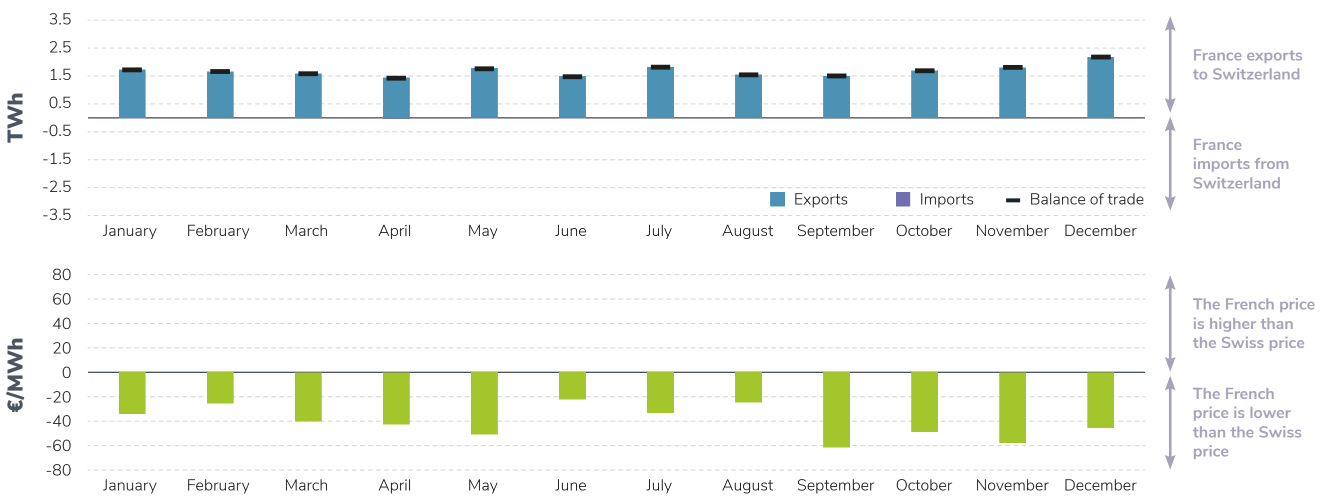
# Switzerland imported from France throughout the year

**The French export balance with Switzerland was clearly positive, reaching 20.1 TWh, the highest value since 2011**, when the balance stood at 25.2 TWh. This 2011 record remained unbroken, however, due to lower exchange capacity resulting mainly from pressures on the Swiss network.

The average spot price in Switzerland was 30% higher in 2025 than in 2024. Only the Italian price was higher among France's neighbours. This increase was partly due to the extended shutdown of the Gösgen nuclear power station, which supplied on average 13% of Switzerland's electricity needs, from May 2025[9]. The difference with the French price (over €40/MWh) is the highest since the creation of the Swiss electricity market.

France's export balance with Switzerland has generally been positive, although growth in solar generation from the mid-2010s onwards has led France to import more often during the spring and summer months. In 2025, trade remained largely export-oriented in every month of the year. In addition, Switzerland plays the role of a "transit country", given its central position in Europe: about 80% of the flows exported to Switzerland are directed to other neighbouring countries, such as Italy (see the analysis in the "*flow tracing*" section).

**Figure 4.12 – Monthly volumes of electricity trading between France and Switzerland (top) and monthly average differences between French and Swiss spot prices (bottom) in 2025**

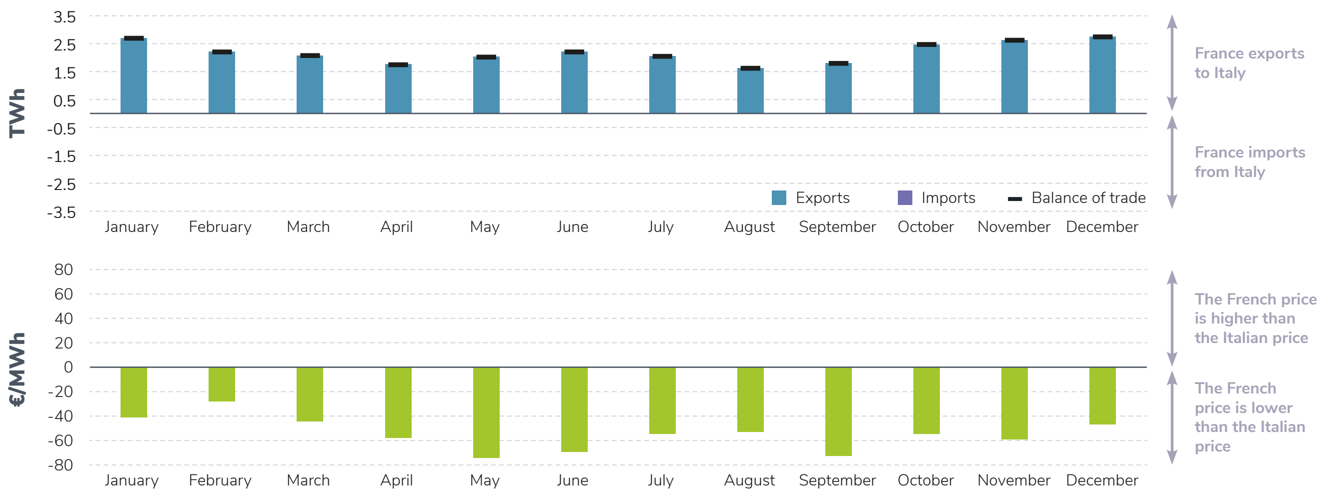



9. The shutdown, scheduled to last until the end of February 2026, was due to the discovery of a potential weakness in the specification of the water supply system.

# Exports to Italy reached a new peak

Historically, trade between France and Italy has tended to favour exports to Italy: France has been a net exporter to Italy every year since 1979. Italian electricity generation, which is still heavily dependent on gas, is structurally less competitive than French or Swiss generation. Since the late 1980s, imports have accounted for between 10 and 15% of Italy's domestic electricity consumption[10]. In 2025, the dynamic was in line with historical trends: France exported massively to Italy. **The net annual balance across this border was 26.2 TWh, the highest ever recorded**, ahead of 2024 (22.3 TWh) and 2002 (22.1 TWh). Volumes are on the rise, due partly to the abundance of low-carbon generation in France, the commissioning of a new 1,200 MW interconnector between France and Italy in 2023, and the fact that there were fewer maintenance operations on the French–Italian interconnectors in 2025 than in 2024. In addition, the average Italian price was €116/MWh, almost double the French price (€61/MWh). This is the biggest price differential between Italy and France since the markets opened.

**Figure 4.13 – Monthly volumes of electricity trading between France and Italy (top) and monthly average differences between French and Italian spot prices (bottom) in 2025**



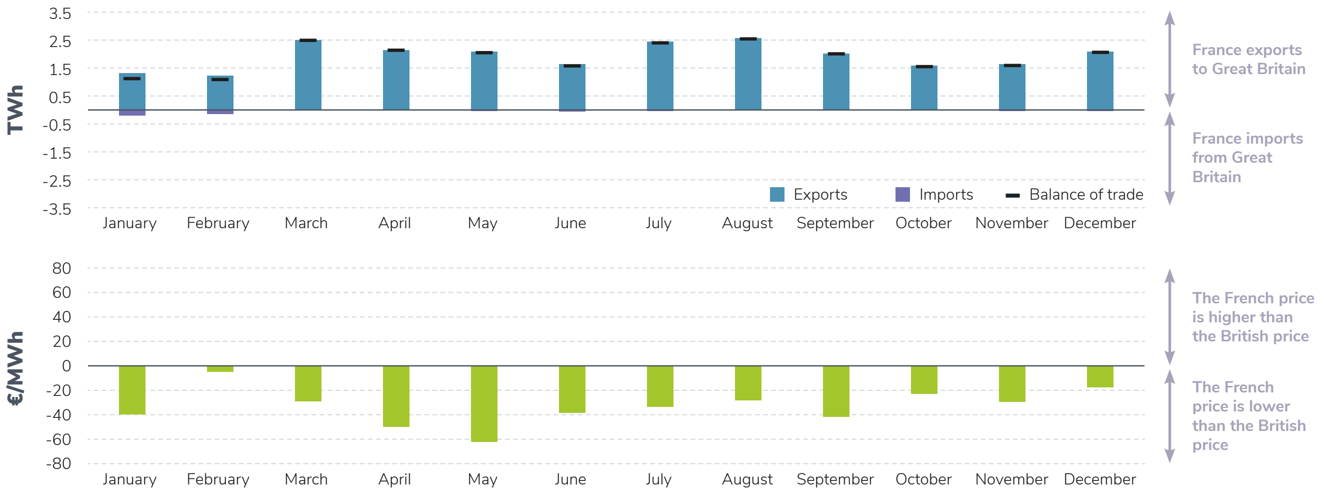

10. Terna, *Dati statistici sull'energia elettrica in Italia*, 2023. Since the commissioning of the new Savoie-Piedmont interconnector in 2023, this proportion has risen to 17%–19%.

# Exports to Great Britain reached their highest level ever

**In 2025, the export balance with Great Britain stood at 22.6 TWh;** 23.2 TWh were exported, and 0.6 TWh were imported, mainly in January and February. This constitutes **the largest net export balance France has ever recorded across this border**, beating 2024's previous record of 20.1 TWh, thanks in particular to better interconnector availability. These consecutive records owe a great deal to the increase in exchange capacity in 2021 (IFA 2) and 2022 (ElecLink).

Since the IFA 2000 interconnector between Great Britain and France was commissioned in 1986, Great Britain has imported large volumes of electricity from France for much of the year, despite the fact that the British electricity generation mix includes a fast-growing proportion of low-carbon energy (mainly wind, but also nuclear and, to a lesser extent, solar, hydropower and biomass). In winter, however, during periods of high wind generation in Britain, or when consumption is high in France, the trade is often reversed, with France importing from the UK.

**Figure 4.14 – Monthly volumes of electricity trading between France and Great Britain (top) and monthly average differences between French and British spot prices (bottom) in 2025**



FOCUS

## Background: Why do we talk about the “British” power system?

We refer to trade with Great Britain, and not with the United Kingdom, because the power systems of the island of Great Britain and of Northern Ireland are not synchronous, are not managed by the same transmission system operator (NESO or National Energy System Operator for Great Britain and SONI for Northern Ireland), and do not belong to the same market area. The Northern Irish power system is integrated with the Republic of Ireland’s system; the two Irish transmission system operators (EirGrid for the Republic of Ireland and SONI for Northern Ireland) have jointly operated a single market area for the entire island of Ireland, the Single Electricity Market, since 2007. The Irish network is interconnected with the British network by three DC links with a capacity of 500 MW each: the East-West Interconnector between the Republic of Ireland and Wales, the Moyle Interconnector between Northern Ireland and Scotland, and Greenlink between the Republic of Ireland and Wales, which was commissioned in 2025. A fourth HVDC link is also planned, this time between the Republic of Ireland and France: the Celtic Interconnector, capacity 700 MW, with commissioning scheduled for 2028.

# The daily trading profiles at each border are driven by consumption and low-carbon generation levels in France and the neighbouring countries

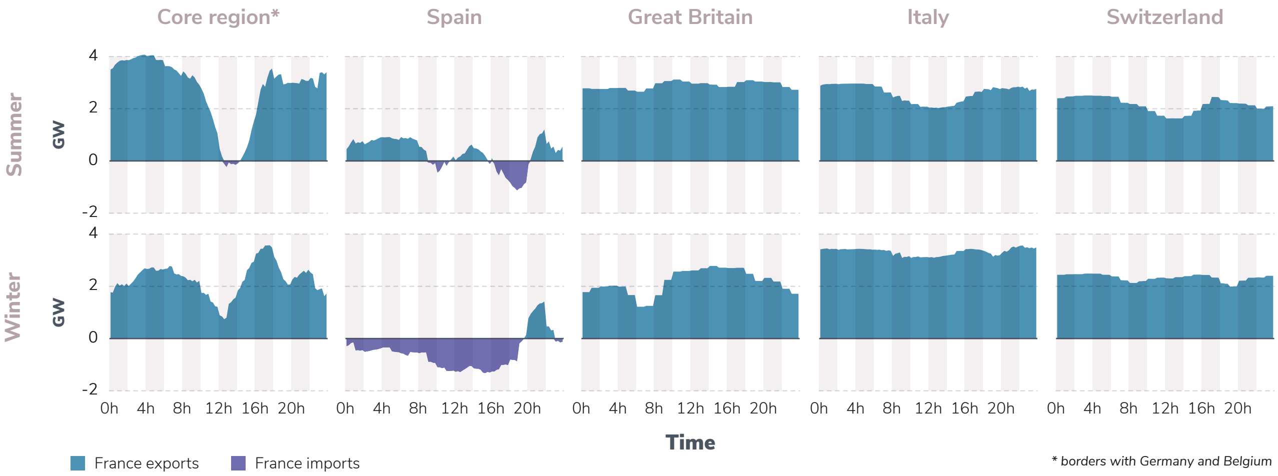
Although France is generally a major electricity exporter on a monthly or annual basis, electricity trading between France and its neighbouring countries changes significantly from hour to hour and from day to day, depending on the characteristics of the different generation mixes and the structure of daily consumption in each country. As a result, hourly trade patterns vary according to season and border.

For example, France's trade with Italy and Switzerland is largely export-oriented for most of the day. On summer days, however, there is a noticeable drop in French exports in the early afternoon, reflecting the rise in solar generation in neighbouring countries, which makes their electricity more competitive at these times and reduces their need to import. This phenomenon is even more visible in trade with Belgium and Germany, which have over 115 GW of solar capacity in total: excluding the late morning and early afternoon, trade amounts to more than 2 GW of exports on average, but this falls sharply from 10 am onwards, even reversing during the summer period, when France becomes an importer.

Contrary to what one might expect, the opposite phenomenon is observed in summer at the Spanish border. Between midday and 4 pm, although Spanish solar output is high, Spain regularly imports electricity from France, where solar generation is also high. These imports, at a time when Spanish consumption peaks due to the use of air conditioning, are generally re-exported to Portugal and, to a lesser extent, Morocco. France then begins to import from Spain in the late afternoon, when French consumption rises, and then exports again after 8 pm when consumption peaks in the evening in Spain.

In Germany, the evening consumption peak is about an hour before the French peak. This schedule difference is reflected in trade with the Core region: in winter, French exports peak between 4 pm and 6 pm, then gradually decline to a trough around 7 pm to 8 pm, corresponding to the time when French demand peaks. This reduction in exports at the point when French consumption peaks at 7 pm in winter is widespread, and can also be seen in the patterns of trade with other countries.

**Figure 4.15 – Monthly electricity trading profile between France and neighbouring countries in 2025**



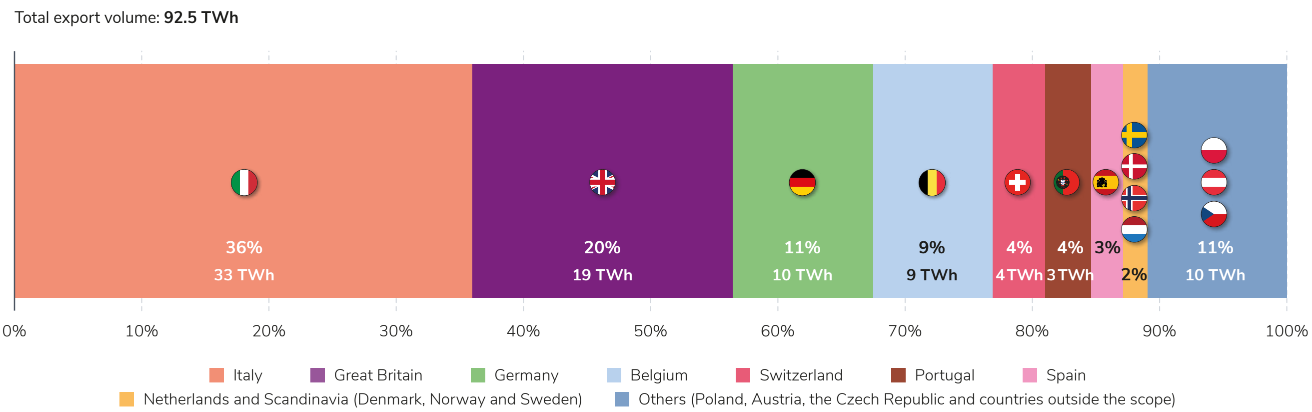
This illustrates how trade makes it possible to take advantage of differences in renewable energy consumption and generation profiles, even though there is a degree of correlation between French renewable generation profiles and those of neighbouring countries, which can limit outlets on the European market (and therefore the possibilities of exporting surplus production) and lead to power generation being modulated downwards.

# French exports reach all of Europe, not just the neighbouring countries

Due to the extensive interconnection of the European grid, France's electricity exchanges with its immediate neighbours, as presented in the border-by-border analysis, may also originate or terminate in countries with which it is not directly interconnected. Schematically, if, over a given period of time, France exports electricity to Spain but Spain exports it to Portugal at the same time, then it may be legitimate to consider that, over the period in question, part of the electricity traded between France and Spain is destined for Portugal. Similarly, if France exports electricity to Italy but imports it at the same time from Germany, it may be legitimate to consider part of these exports as coming from Germany and not from French production. The results of the analysing the trade using this approach, known as "flow tracing", with a European scope extended to 15 countries[11], are presented here. This is not measured data but the results of modelling[12], but it can still provide additional information useful for understanding the operation of the European power system.

This analysis shows, firstly, that a large proportion of France's imports "pass through" the country, and do not supply French consumption. **France was a net exporter almost 99% of the time in 2025.** In practice, even if France is a net exporter during a given period, it may simultaneously be importing from another country. A situation in which exports exceed imports (net export position) reflects the fact that these imports do not correspond to a need within France during these periods, but to exchanges of electricity that pass through its network. **The volume of imports supplying French consumption, as defined by this approach, is thus extremely low: less than 0.2 TWh over the year.**

**Figure 4.16 – French exports to the extended scope in 2025***




* *Exports reconstructed by RTE based on trade flows between the various European countries.*

**Data:** RTE, ENTSO-E, NESO.

11. The 15 countries are: France, Spain, Portugal, Italy, Switzerland, Austria, Germany, the Czech Republic, Poland, Belgium, the Netherlands, Sweden, Norway, Denmark and Great Britain. Ireland is excluded due to the insufficient quality of the data available. A wider group of countries, extending as far as Greece and Finland, was also studied: the inclusion of countries further away than the 15 selected, whose power systems are relatively small compared with France's, does not substantially alter the results presented here.
12. The foundations of the approach used in this section are set out in detail in: J Bialek, *Tracing the flow of electricity*, 1996.

Analysing the trade across each border, we can see that exports to Switzerland are much lower according to the “flow tracing” analysis than those identified in the bilateral analysis for borders with direct neighbours. This is because Switzerland is a transit country[13]: Switzerland's imports of French electricity for its own consumption represented only 4% of French exports in 2025 (4 TWh), whereas the total Swiss imports (including “re-exported” flows, particularly to Italy) accounted for 19%. As a result, Italian imports of French electricity, which at first glance represented only 25% of French exports, actually accounted for 36% (or 33 TWh) once flows transiting via countries such as Switzerland are included.

*Ultimately,* **15% of French exports supplied consumption in non-bordering countries in 2025.** The largest of these markets is Portugal, with 4% by volume (3 TWh), i.e. more than the French exports supplying Spanish consumption (2 TWh). Finally, around 11% of France's exports are destined for the rest of Europe (including Austria, Poland, Denmark and the Netherlands).

13. See: RTE, 2023 *Electricity Review – Trading chapter – Focus: Switzerland, a transit country for electricity*, 2023

# With the transformation of the French and European electricity mix, the French power system is playing the role of an "electricity crossroads"

**Because of its position as an "electricity crossroads" between its neighbours to the north, south-west and east, France automatically plays the role of a transit country.** In 2025, the volume of flows passing through France amounted to 11 TWh; this is similar to the 2024 volume, down on 2022, and is the lowest since 2015. This can be explained by the abundance of low-carbon domestic production, which made France's average spot price the lowest among its neighbours in 2025, and primarily supplied the import needs of its neighbours. In 2022, when French nuclear output was at its lowest level since 1988 and hydropower production was also low, a record 32 TWh passed through France,

**Figure 4.17 – Volume of flows passing through France, by origin (France's direct neighbours), since 2001**

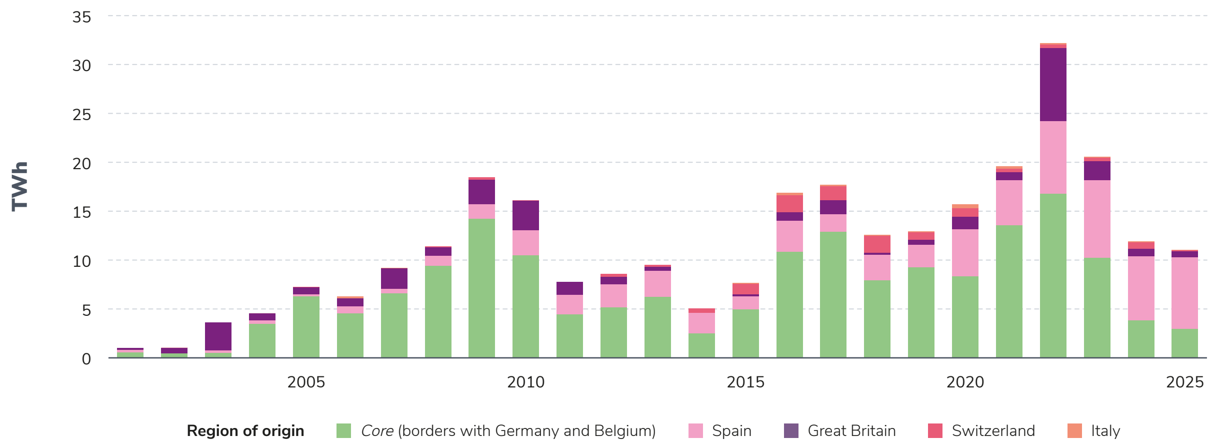



**Figure 4.18 – Volume of flows passing through France, by destination (France's direct neighbours), since 2001**

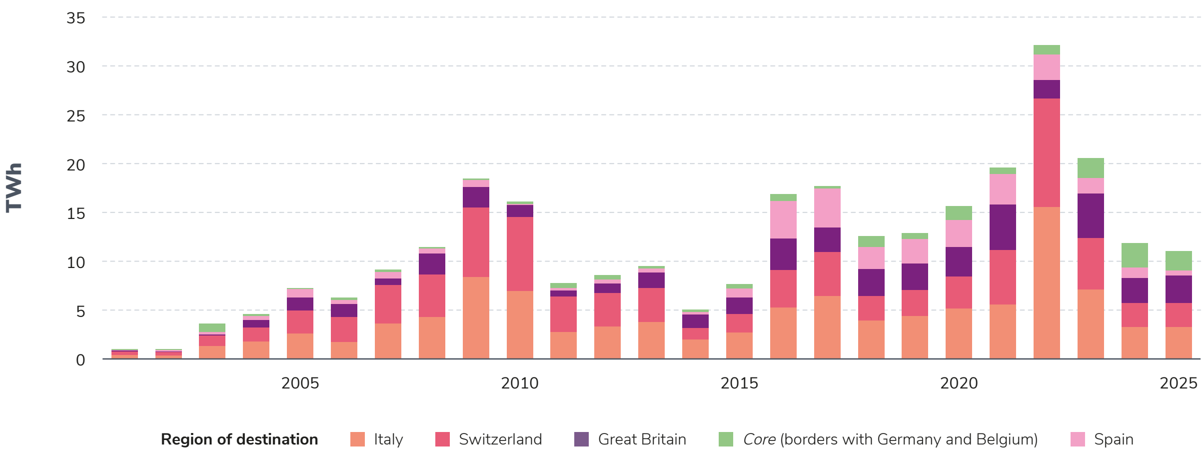
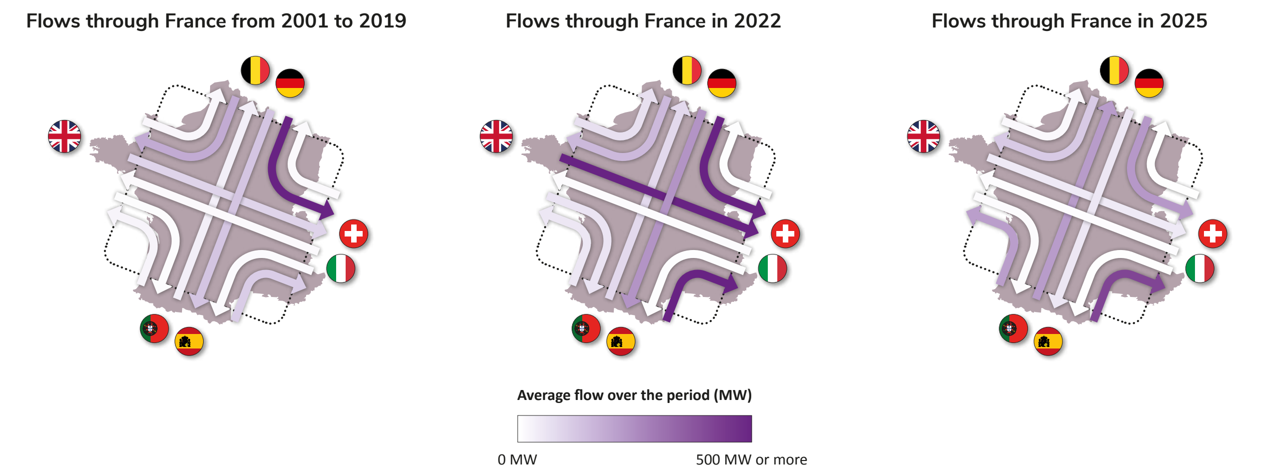


**Figure 4.19 – Evolution of flows through the French power system**




mainly from Core, Spain and Great Britain to Italy and Switzerland, where spot prices were higher than in France.

Through flows reflect the operation of the interconnected European power system, in which economic optimisation leads to the least costly – and generally least carbon-intensive – generation sources across Europe being called on to feed consumption, independently of national borders, within the limits of interconnection capacities and the transit capacities of the national networks.

Over the last few years, through flows have risen from Spain, as a result of its increasingly competitive generation mix, but decreased from Germany and Belgium, whose trade balances have recently switched from exports to imports – see the previous section. Of the 11 TWh that passed through France in 2025, 7 TWh came from Spain and 3 TWh from the Core region. Historically, these through flows were mainly destined for Italy and Switzerland[14], though the distribution was more balanced in 2024 and 2025.

For example, the increase in exchange capacity with Spain over the coming years should lead to an increase in transits to the rest of Europe, which will generate more cross-border flows on the French network. For these interconnections to be exploited to the full, the internal network routes that will enable these transits to other countries also need to be identified and strengthened.

14. Exports to Switzerland may be re-exported, particularly to Italy. See : RTE, *2023 Electricity Review – Trading chapter – Focus: Switzerland, a transit country for electricity*, 2023

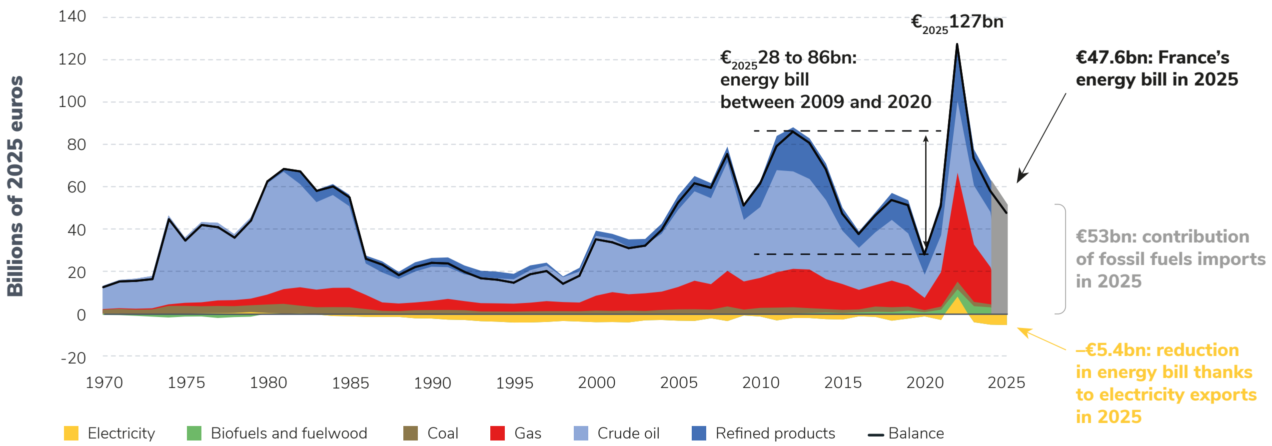
# The value of trade is increasing, but remains low compared to the cost of fossil fuel imports

**The total net value of France's electricity exports amounted to €5.4 billion in 2025** (or around €9 billion taking into account the average price in the countries to which France exports), **a level slightly higher than the previous year.** This amount helps to reduce France's "energy bill", but it is still low compared with the cost of fossil fuel imports, which represent the largest heading in France's trade deficit. In 2025, fossil fuel imports cost €53 billion[15]. In 2022, they amounted to over $€_{2025}$110 billion in the context of the energy crisis; by comparison, the fact that France was, unusually, an electricity importer that year only cost around $€_{2025}$8 billion.

As the findings of the latest 2025 Generation Adequacy Report published by RTE also make clear, **this provides a valuable opportunity to take advantage of the abundance of low-cost, low-carbon electricity generation to decarbonise the French economy by replacing fossil fuels, which still account for almost 60% of the energy consumed in France.** Electrifying energy uses would enable French consumers to benefit from low-cost electricity generation, strengthen the country's energy sovereignty and shield it from the volatility of fossil fuels prices resulting from events affecting the global economy.

Between 2002 and 2019, the annual net value of France's electricity trade fluctuated between $€_{2025}$1 and 3 billion. From 2021 onwards, the effect of the energy crisis in Europe became apparent: the value of the electricity traded by France rose sharply, driven primarily by prices. In 2024, falling prices partly offset the effect of higher export volumes. In 2025, the value of electricity trading between France and its neighbours was slightly higher, due to a higher export balance and prices that were also slightly higher.

**Figure 4.20 – Trends in the French energy bill between 1970 and 2025**




**Data source:** Customs for 2025, SDES until 2024 – **Graph:** RTE

15. Source: Customs

**Figure 4.21 – Value of electricity traded between France and its neighbours**

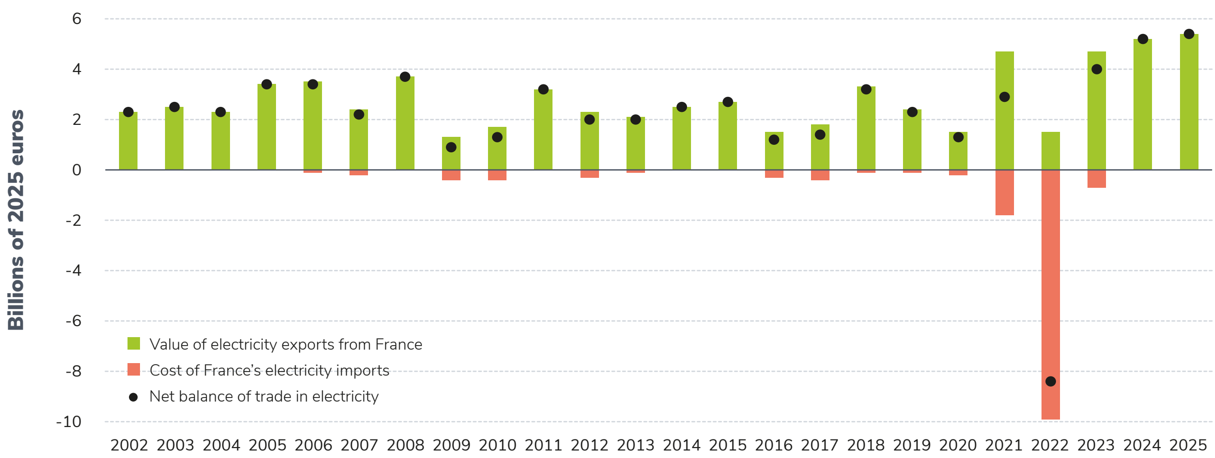



**Figure 4.22 – Volume exported by France in each price range since 2001**

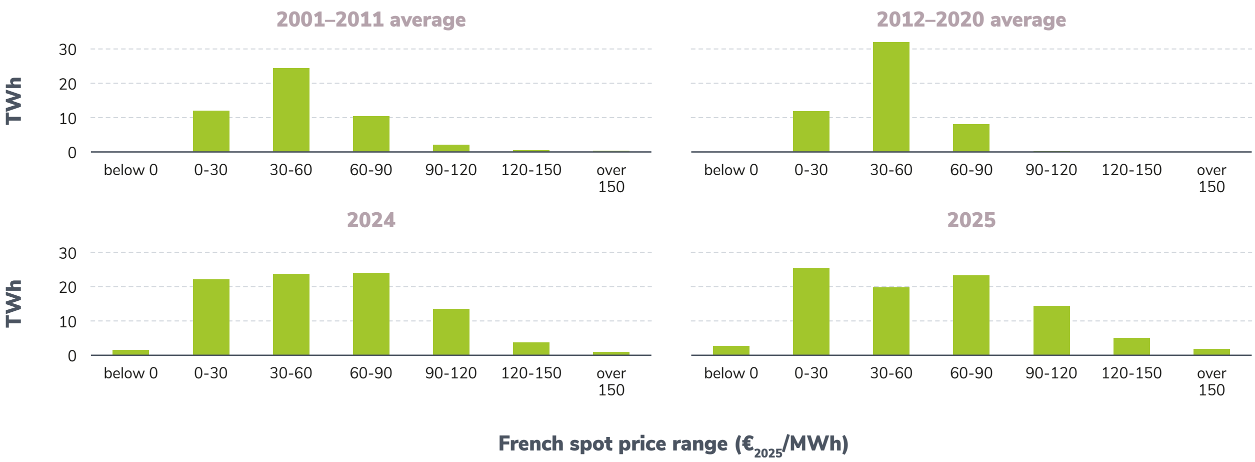
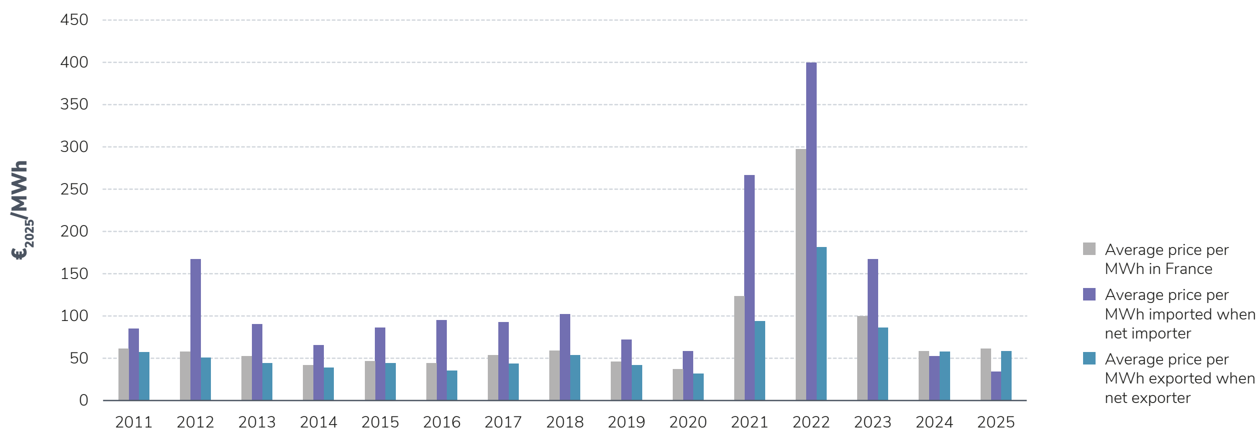



**Figure 4.23 – Average price per MWh exported and imported (as net exporter/importer) and average price in France***




** The volumes are valued at the French spot price. Average prices are weighted by net volumes exported and imported. The average price in France is not weighted.*

As a result of increased price volatility, volumes traded at relatively high prices increased (23% of volumes were exported at prices above €$_{2025}$90/MWh, compared with 20% in 2024 and less than 1% over the 2012–2020 average). Volumes traded at relatively low prices also increased slightly (13% of the volumes exported were at prices below €$_{2025}$10/MWh, compared with 12% in 2024 and 1% over the 2012–2020 average).

Historically, since the markets were opened up in 2002, the average spot price when France was a net exporter[16] has been lower than the price when France was a net importer. This is because most of the periods when France imported electricity corresponded to periods of high consumption, when prices also tend to be higher. This situation was reversed in 2024 and even more so in 2025: thanks to the abundance of low-carbon generation in France, there were only rare periods when France was a net importer (around 100 hours in 2025). During these times, France was mainly importing due to the abundance of renewable generation in neighbouring countries, which meant that half of these hours were characterised by negative prices. **The average import price[17] was €33/MWh, the lowest level since the markets opened.**

The average price per MWh exported in 2025 (€59/MWh at the French price) is close to the average French spot price (€61/MWh). It remains close to the levels of the previous year and slightly higher than during the 2010s. Valued at the average price in the countries to which France exports, on the other hand, it came to €101.5/MWh. **So, as in 2024, France did not "dump" its electricity at rock-bottom prices in 2025: it exported its competitive surplus production almost continuously, benefiting from a higher price differential with neighbouring countries than in 2024.**

16. I.e. when France is exporting more electricity than it is importing. When France is a net exporter, it is possible that it may still be importing across one or more of its borders.

17. I.e. the average of the spot prices weighted by the corresponding traded volumes, over the time intervals when France is a net importer (i.e. only 0.2 TWh)

# Emissions

2025 ELECTRICITY REVIEW

## The carbon content of French electricity generation is one of the lowest in Europe, representing leverage for decarbonising the country's energy consumption

In France, electricity production is already almost all low-carbon, so the volume of emissions is low compared with other sectors of the economy and with electricity generation in neighbouring countries.

On the other hand, France's energy consumption (across all energy sources) still relies heavily on imported fossil fuels, at almost 60%. This highlights the value of accelerating electrification based on an electricity mix that has already been largely decarbonised (see the *Electrification* chapter).

For the third year running, direct emissions from French electricity generation continued to fall in 2025, reaching an all-time low since 1945 of 10.9 $MtCO_2e$. This level is comparable to, but slightly lower than, the 2024 figure (11.7 $MtCO_2e$).

In terms of carbon intensity, i.e. the quantity of emissions per quantity of energy produced, French electricity is among the least carbon-intensive in Europe, with 19.6 $gCO_2e$ per kWh generated in 2025, well ahead of most other countries; the average in the European Union (plus Switzerland, Norway and the United Kingdom) is 175 $gCO_2e$ per kWh. Despite relatively high per capita electricity consumption in relation to comparable European countries[1], electricity generation represents only a small proportion of the national carbon footprint: less than 5% in France, compared with around 20% in Germany, Spain and the European Union as a whole[2,3].

Fossil-fired electricity generation was used particularly infrequently in 2025, which explains these unusually low levels of emissions (see the *Generation* chapter). In particular, the most emissions-intensive fossil fuels, coal and oil, were scarcely used at all. Gas-fired generation, which currently relies mainly on fossil gas, emits slightly smaller quantities of greenhouse gases than coal and oil. It currently accounts for the bulk of fossil-fired electricity generation in France, and also reached an all-time low in 2025.

1. Partly because of the higher proportion of electric heating compared with other countries. In 2024, electricity consumption was about 6,600 kWh/capita in France, compared to 6,000 kWh/capita in Germany, 5,900 kWh/capita in the European Union and less than 5,400 kWh/capita in Spain and Italy (source: Eurostat).
2. Sources: CITEPA, *Rapport Secten 2025*, 2025; European Environment Agency; Eurostat; ENTSO-E; calculations by RTE.
3. The gross territorial emissions of the European Union amounted to 3,039 $MtCO_2e$ in 2024 (source: European Environmental Agency). Direct emissions due to electricity generation in the European Union reached 519 $MtCO_2e$ (source: Ember Climate, *Yearly electricity data*, 2025).

**With French electricity generation now almost entirely low-carbon, the main challenge for France is to replace fossil fuels with low-carbon electricity on a large scale in sectors other than electricity generation (such as transport, buildings and industry).** This will mean an increase in electricity consumption in the medium to long term.

The decarbonisation of the electricity mix has been achieved gradually and successfully over the last few decades, with the development and maintenance of a large base of low-carbon hydroelectric and nuclear generation, followed by the closure of the most polluting power plants (coal and oil-fired) and the development of solar and wind generation. For the French energy system as a whole, two goals must now be pursued at the same time:

- **from the consumption viewpoint , making the massive switch from fossil energy vectors to electricity a reality** across the economy (transport, industry, tertiary and residential buildings (see the *Electrification* chapter) and in new energy uses (data centres, electrolysers);
- **from the electricity generation viewpoint, establishing a development pathway for low-carbon generation resources** that is consistent with the target pathway for decarbonising the economy.

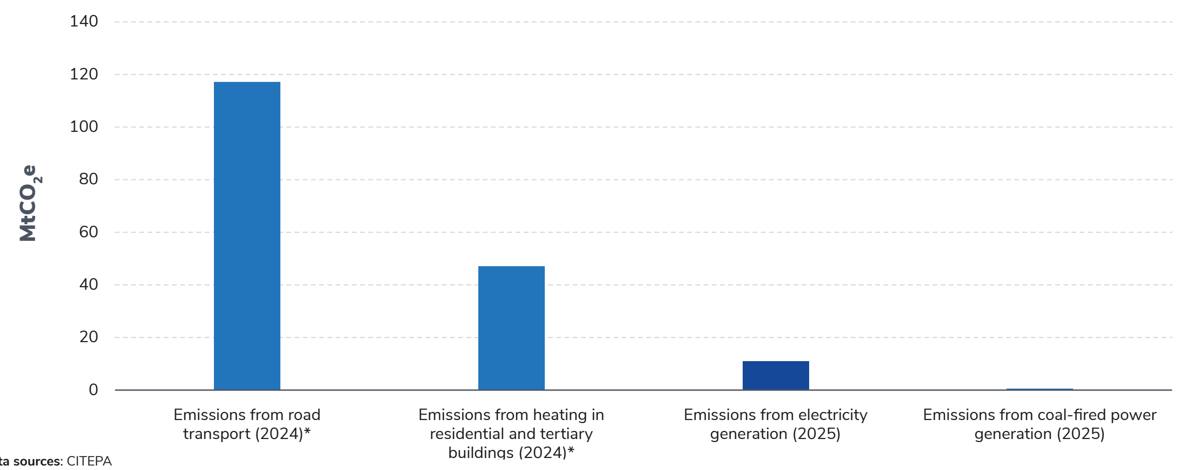
These issues are examined and developed in detail in the 2025–2035 Generation Adequacy Report published by RTE at the end of 2025.

## French electricity generation has been largely decarbonised since the late 1980s, and is now almost entirely low-carbon

From the beginning of the 20th century, it is possible to identify six major periods for the French power system in terms of greenhouse gas emissions[4]:

- **Before 1945**, electricity played a relatively minor role in the country's energy system. It became more widely used over the first half of the 20th century, particularly for lighting, but there was still no unified transmission grid, and generating facilities were mostly private, for industrial use. The bulk of electricity generation came from coal and hydropower;

**Figure 5.1 – Orders of magnitude of greenhouse gas emissions in France for a selection of energy-related uses or activities**

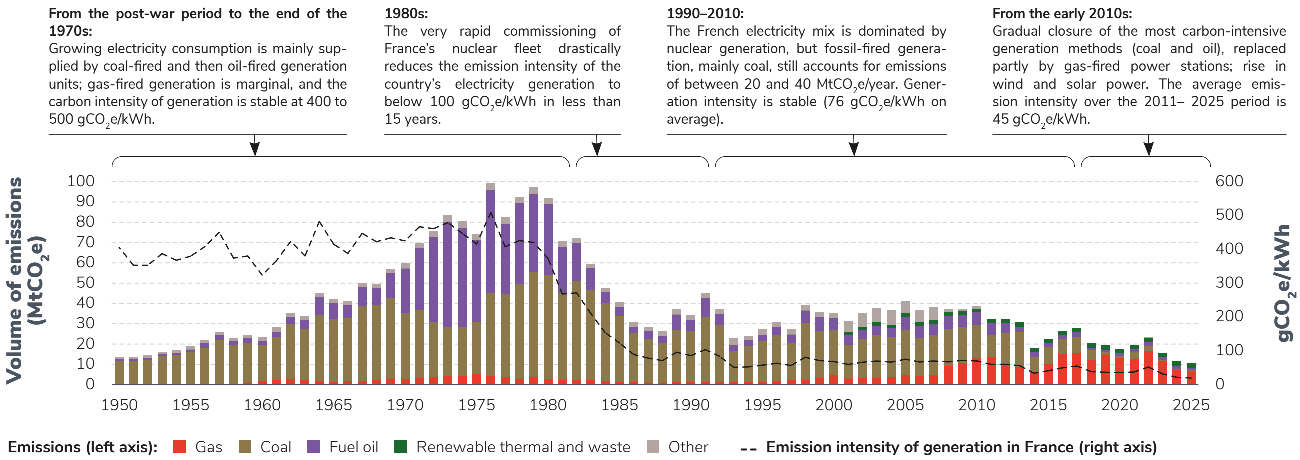



*** Data sources:** CITEPA

4. The emission factors of the different generation sources used to calculate the emissions over the entire period 1950–2025 are the current emission factors (see Appendix). Strictly speaking, it should be taken into account that emission factors tend to decrease (very slowly) over time with improvements in plant efficiency, changes in the quality of fossil fuels, etc. However, the approximation made here is not likely to substantially modify the results of the analysis.

- **From the post-war period until the end of the 1970s**, generation was highly carbon-based; the significant increase in electricity consumption (+1% per year on average), in a context of strong economic growth and the electrification of the country, was mainly covered by hydropower and coal- and oil-fired power plants. The average intensity of electricity generation in France thus remained between 400 and 500 $gCO_2e/kWh$. In 1976, annual emissions related to electricity generation in France reached nearly 100 $MtCO_2e$;
- **During the 1980s**, the rapid commissioning of the nuclear reactors that make up the current fleet, in parallel with continued growth in national electricity consumption (+0.4% per year on average over the decade), resulted in a very rapid decarbonisation of the French electricity mix[5]. This deployment saw the fuel-oil fleet almost disappear and emissions related to coal halve between 1980 and 1990. As a result, the carbon intensity of French generation was divided by four in ten years: in 1990, it was less than 100 $gCO_2e/kWh$;
- **Between 1990 and the late 2000s**, emissions and the emission intensity of generation remained relatively stable. The electricity mix was dominated by nuclear power, but a proportion (between 10 and 20 GW) of the fossil-fuel thermal plants, particularly coal-fired, were still in operation. Greenhouse gas emissions (between 20 and 40 $MtCO_2e$) and carbon intensity (around 75 $gCO_2e/kWh$) remained stable over the period;
- **From the early 2010s until the start of the energy crisis in 2022,** the oil- and coal-fired generating fleet was gradually scaled back, driven by stricter targets for reducing greenhouse gases and pollutant emissions. Some of this production capacity has been replaced by gas-fired power stations, which emit less for the same amount of energy produced. The 2010s were also marked by strong growth in wind and solar power. All these factors together contributed to further reducing the intensity of French electricity generation, which reached 47 $gCO_2e/kWh$ on average over the period 2010–2023. At the end of this period, it can now be said that the French electrical system has virtually completed its decarbonisation process. The energy crisis of 2022, which led to a one-off rise in emissions that was absorbed the following year, did not significantly alter this trend;

**Figure 5.2 – Direct greenhouse gas emissions related to electricity generation in France and emission intensity of French electricity generation between 1950 and 2025**




*Calculated using current assumptions for fuel emission factors and plant efficiency, which may lead to a slight underestimation of historical emission volumes.*

5. The main objective at the time was the improvement of energy sovereignty and not the decarbonisation of the mix.

- **In the wake of the energy crisis, the French power system is entering the next phase of its transformation: providing leverage for the decarbonisation of the economy as a whole.** In this new phase, we are no longer talking about decarbonising electricity, but all energy consumption in France. This will require a massive increase in the use of electricity in all sectors, accompanied by the development of low-carbon electricity generation infrastructure capable of supporting the increase in consumption. As the analyses in the various chapters of the Electricity Review and the latest Generation Adequacy Report show, this phase has yet to achieve real momentum: the stagnation in electricity's share of final energy consumption highlights the delay in electrification. The abundance of low-carbon electricity generation, on the other hand, presents a real opportunity to accelerate the electrification of the French power system.

## Sustained low emissions reflect a new era for electricity generation in France

In 2022, the crisis in electricity generation in France led to a real but limited increase in emissions from the French power system (see the *Emissions* chapter of the 2022 Electricity Review). This one-off cyclical episode did little to alter the broader dynamic of deep and gradual decarbonisation that has taken shape over the last ten years.

Emissions quickly returned to a particularly low level: **between 2022 and 2023, generating emissions fell by almost a third to 15.8 MtCO$_2$e, their lowest level since 1953.** This drop was mainly due to the upturn in low-carbon generation, and particularly the recovery in nuclear power. **The downward trend then continued: in 2024 emissions reached 11.7 MtCO$_2$e, and in 2025 they stood at 10.9 MtCO$_2$e. This is once again a historically low level, comparable to the early 1930s**, when the volume of electricity generation, entirely coal-fired, was almost 30 times lower than today.

Just under two-thirds (6.7 MtCO$_2$e) of generation-related emissions come from gas as a generating source. Of these, almost 40% (3.2 MtCO$_2$e) are associated with production facilities that fall into the cogeneration category, i.e. facilities that mainly produce heat to supply industrial processes or district heating networks, with electricity as a by-product. They operate regardless of conditions in the electricity market, and correspond to a "base" level of generation and emissions (see the *Generation* chapter) that cannot

**Figure 5.3 – Direct greenhouse gas emissions related to electricity generation in France (left axis) and emission intensity of French electricity generation (right axis) between 2017 and 2025**

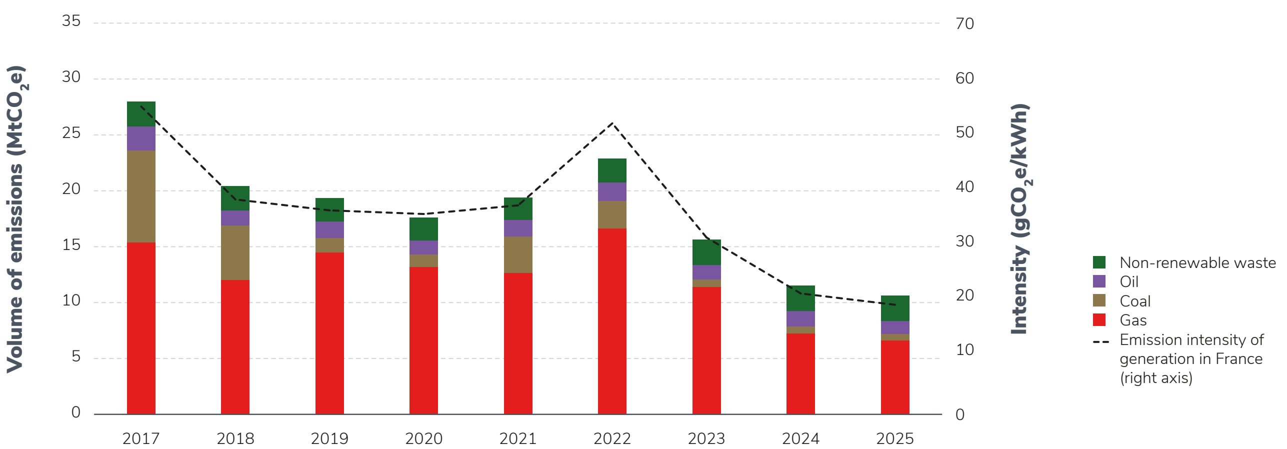
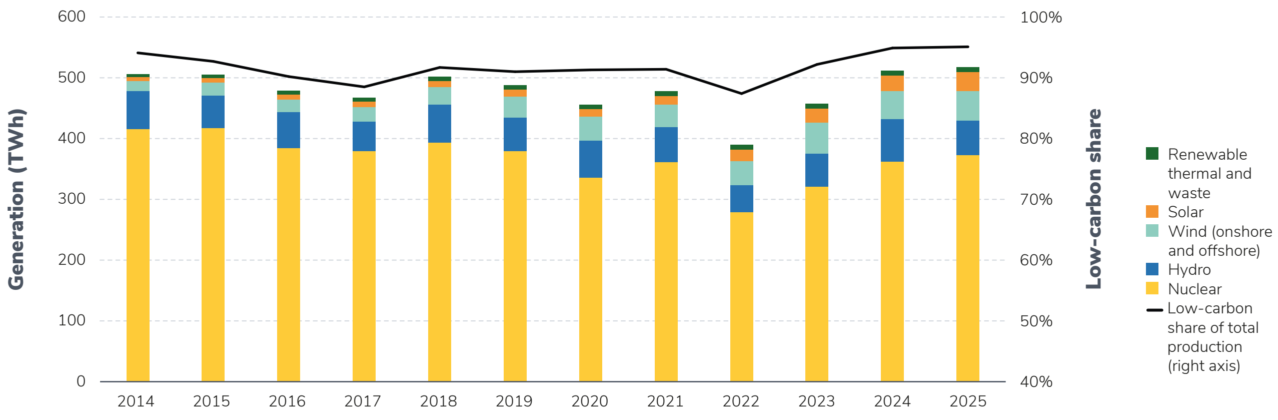


**Figure 5.4 – Decarbonised electricity generation in France (left axis) and decarbonised share of total electricity generation (right axis) between 2014 and 2025**




*Power generated from household waste is considered 50% renewable. Seventy percent of PSH pump consumption is deducted from hydropower generation in accordance with European Directive 2009/28/EC.*

easily be reduced. Electricity generation from the incineration of non-renewable waste, which is also mainly determined by the need to deal with waste, independently of conditions on the electricity market, accounts for around one-fifth of the volume of emissions, or 2.3 $MtCO_2e$.

The proportion of emissions that cannot be attributed to cogeneration or inflexible sectors thus represents only 40% of the emissions linked to electricity generation. This proportion corresponds to generation resources that help to balance the system during periods of high consumption, with relatively short operating times. These "residual" emissions from the French mix should be seen, at least in the short term, as enabling the system to function properly and the low-carbon generating fleet to develop: they represent a low volume of emissions compared to the service they provide to the system.

**Figure 5.5 – Daily emissions from French electricity generation in 2025**

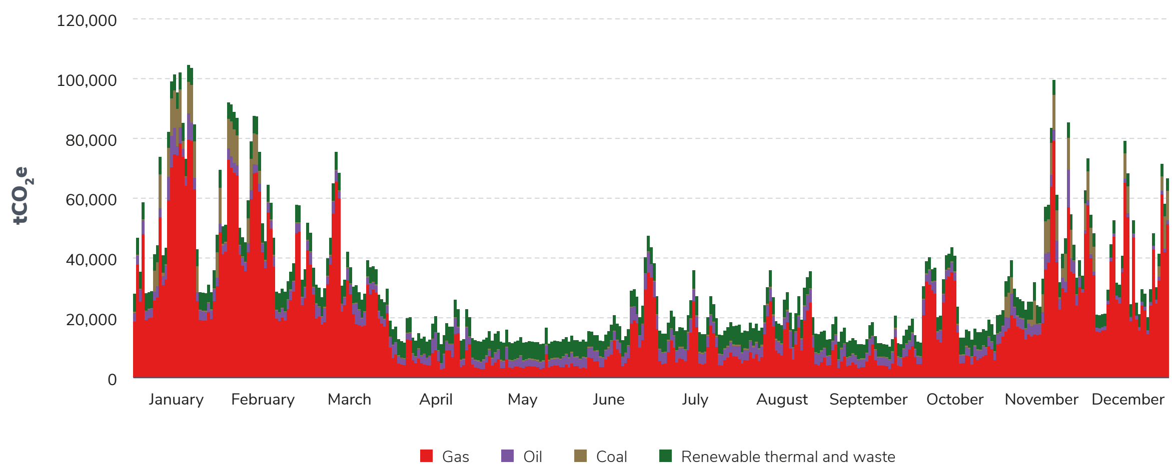
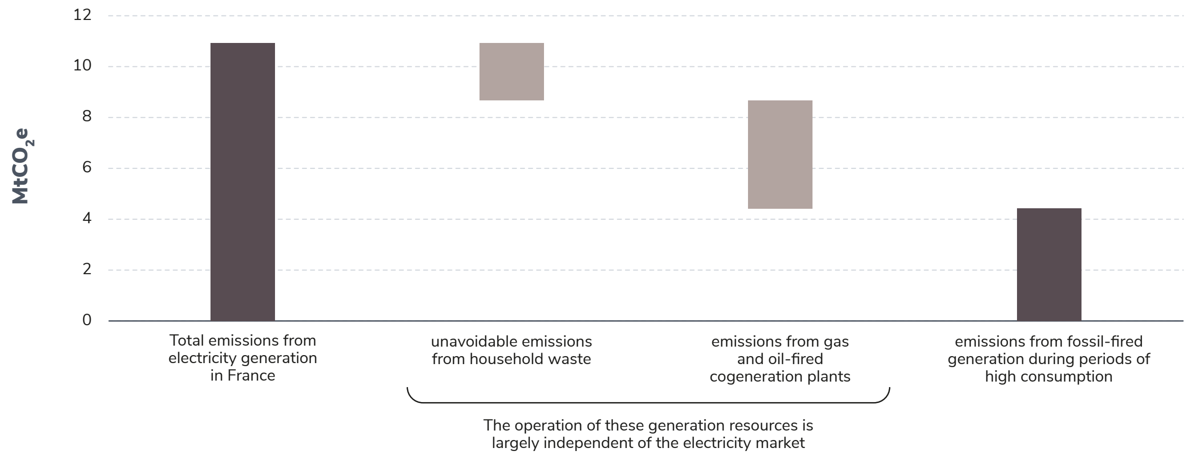


**Figure 5.6 – Breakdown of total emissions from French electricity generation by origin**

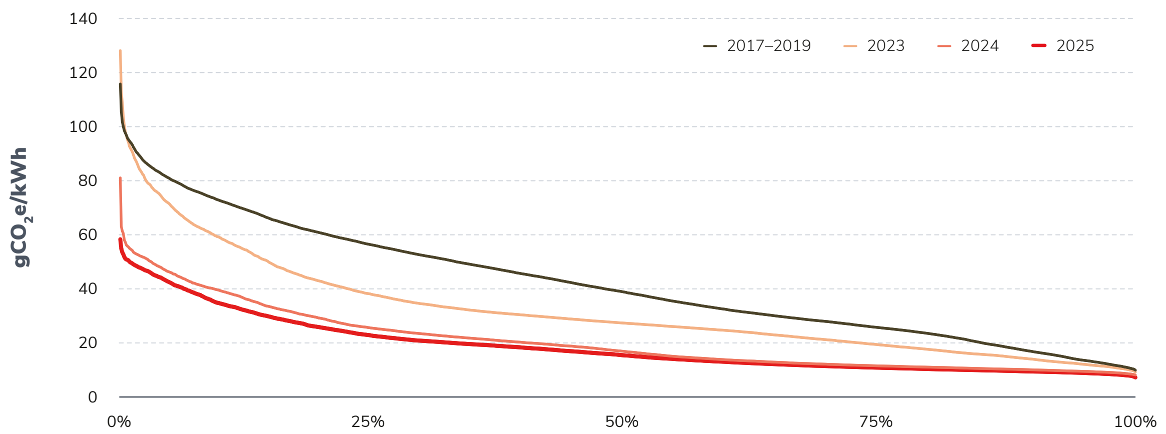



Coal is hardly used at all, except during periods of high consumption: it generated less than 0.6 $MtCO_2e$ over the year as a whole, which is roughly the equivalent of one day's road transport emissions in France. It is interesting to note that the total emissions from electricity generation are equivalent to around three weeks of road transport emissions (see Figure 5.1 above).

## On an hourly basis, the carbon intensity of the French power system remained limited throughout the year

On average over 2025, the carbon intensity of French electricity generation was 19.6 $gCO_2e/kWh$, and the carbon intensity of French consumption, taking electricity trading with other countries into account, was 20.0 $gCO_2e/kWh$. The fact that these two values are almost identical can be explained by France being almost exclusively a major net exporter over the year (see the *Trading* chapter).

**Figure 5.7 – Monotonic intensity of greenhouse gas emissions from French electricity consumption over different periods**



The intensity of both generation and consumption was below 15 $gCO_2e/kWh$ almost half the time. This practically irreducible level, which can be seen as the system's "background intensity", corresponds to emissions from sources that are largely inflexible from the point of view of the power system (see the analysis in the previous section), i.e. waste incineration and cogeneration.

Even in a low-carbon power system, there are likely to be occasional spikes in the intensity of generation and consumption. These occur mainly in winter, during periods of high consumption, when it is necessary to call on fossil-fired thermal generation and possibly imports from countries whose power is more carbon-intensive. In 2023, for example, the carbon intensity of consumption exceeded 100 $gCO_2e/kWh$ around 3% of the time.

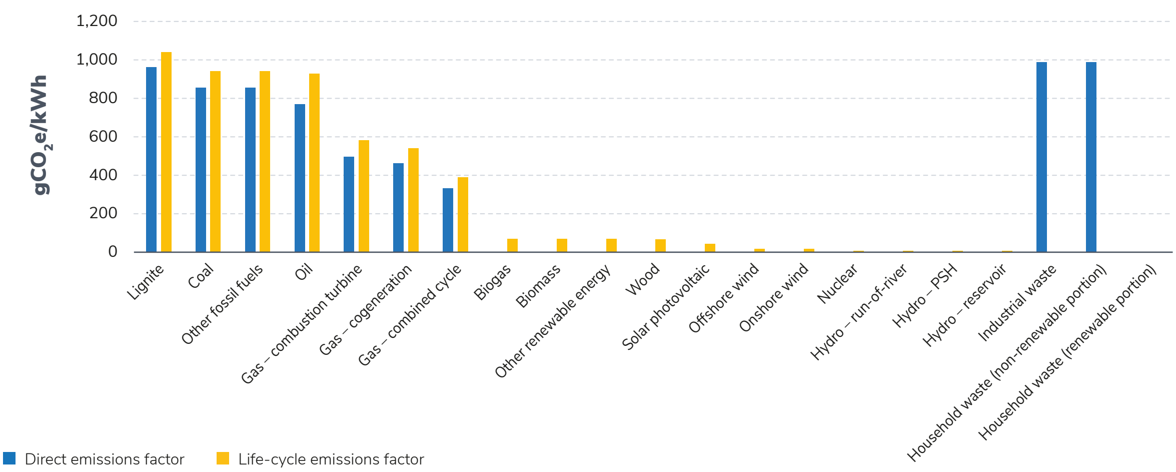
In 2025, this intensity remained limited even during periods of high consumption, reaching a maximum of 58 $gCO_2e/kWh$. This is a very low level, below the average intensity of French production over the whole of 2012.

## Even taking life-cycle emissions into account, emissions related to the French power system remain very low

The carbon intensity related to electricity generation can be calculated by considering only direct emissions, as in the previous paragraphs, or by including all emissions related to electricity generation over the life cycle. As well as the direct emissions related to combustion in power plants (for fossil fuel-fired power plants), this second approach includes all the emissions related to the life cycle of generating facilities: from the extraction and transport of fuels and raw materials or equipment to the construction of infrastructure allowing the generation of a given amount of energy. Some generation sources, such as wind, solar and hydropower, do not cause direct emissions, but the construction of dams, the manufacture and transport of solar panels and wind turbines and their installation generate indirect emissions that are taken into account in this approach.

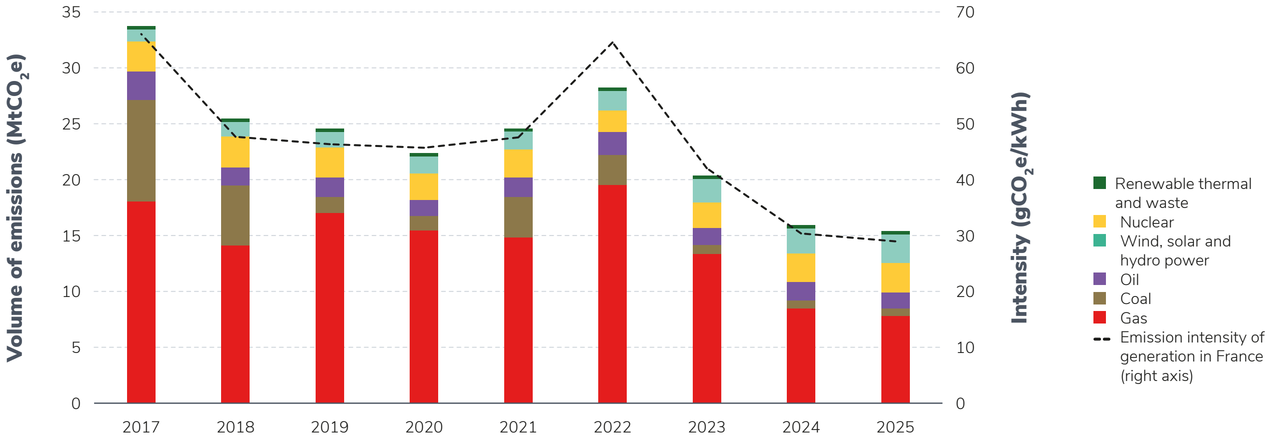
In 2025, the emissions attributable to French electricity generation in terms of life cycle analysis were 15.7 $MtCO_2e$, very close to the total recorded in

**Figure 5.8 – Emissions factors for different electricity generation sources**




*The emissions factors used by RTE to calculate emissions are the result of internal work; they are based on a range of sources and models, and are harmonised between the various publications (Generation Adequacy Reports, Electricity Reviews, etc.).*

**Figure 5.8 – Life-cycle greenhouse gas emissions related to electricity generation in France (left axis) and emission intensity of French electricity generation (right axis) between 2017 and 2025**




2024 (16.2 $MtCO_2e$). Life cycle analysis leads to the same conclusion as analysing direct emissions: the emissions from electricity generation in France are among the lowest in Europe. The intensity of generation reached 29.0 $gCO_2e/kWh$ across the life cycle.

Greenhouse gas emissions over the life cycle of low-carbon energy sources remain very low compared to those of fossil-fuel thermal facilities: 16 $gCO_2e/kWh$ for onshore wind power, 17 $gCO_2e/kWh$ for offshore wind power, 43 $gCO_2e/kWh$ for photovoltaic solar power, 7 $gCO_2e/kWh$ for nuclear power and 6 $gCO_2e/kWh$ for hydropower, compared to 941 $gCO_2e/kWh$ for coal-fired power plants, 928 $gCO_2e/kWh$ for oil-fired power plants and 389 $gCO_2e/kWh$ for combined cycle gas power plants, which are the most efficient gas-fired power plants.

As the share of fossil-fired generation in the production mix decreases, the proportion of emissions linked to direct emissions from combustion decreases, and the share of emissions linked to the rest of the life cycle of the generating plants automatically increases. That being the case, despite their now-significant share of the electricity mix, the combined contribution of wind, solar and hydropower to life-cycle emissions from electricity generation remains very low. In 2025, these sources accounted for around 16% of total life-cycle emissions from electricity generation in France (i.e. 2.6 $MtCO_2e$), while contributing around 25% to the country's electricity mix. Fossil-fired sectors, by contrast, made up less than 4% of the national generation mix, but accounted for 63% of life-cycle emissions from electricity generation. Furthermore, when looking at the wider scope of the country's carbon footprint[6], the emissions associated with these three renewable generation sources represent less than 0.5% of the total.

6. The carbon footprint refers to all emissions, both domestic and foreign, that are attributable to the national consumption of a given country. This therefore counts emissions generated abroad by the production of goods or services consumed in the country in question, but not emissions generated in the country in question by the production of goods or services that are consumed abroad. It is a concept close to the life cycle, but distinct: the carbon footprint is based on the attribution of emissions to the consumption of a given territory, while the life cycle analysis is based on the attribution of emissions to a given energy use, activity or object. The proportion of the carbon footprint made up of life-cycle emissions from renewable power is given here as a guide based on the total 2024 footprint, as the value of the footprint for 2025 is not yet known.

## French low-carbon electricity exports are an asset for the European power system

As French electricity generation is already almost entirely low-carbon, the country's electricity exports, which reached a record level in 2025 (92.3 TWh, see the *Trading* chapter), are helping to avoid emissions elsewhere in Europe. Exports of electricity to other countries make it possible to limit fossil-fired generation, particularly from coal and gas, in neighbouring countries.

To evaluate these avoided emissions, we can compare the intensity of French generation with that of the countries to which the electricity is exported, for each hour. The emissions avoided thus depend on the carbon intensity differential between the generation mixes of France and the other countries on one hand, and on the quantity of electricity exported on the other. This approach necessarily involves simplifications, and omits certain phenomena specific to the operation of the power system: in particular, it does not account for the effect that a change in trade would have on the order of economic precedence in each country. That said, an analysis of the avoided emissions calculated in this way does reveal trends, particularly in terms of time and geographical distribution.

In 2025, exports from France prevented the emission of almost 27 $MtCO_2e$ in Europe, nearly half of it in Italy and a fifth in Germany. This is a record level, driven on one hand by the slight increase in the export balance, and on the other by the different distribution of exports: specifically, the proportion of exports to Italy, a country with one of the largest carbon intensity differentials, was higher in 2025, while exports to Spain, whose mix is mostly low-carbon, fell (see the *Trading* chapter). More broadly, the increase in the export balance over the last two years has offset the effect of the gradual decarbonisation of power generation elsewhere in Europe (see the *Europe* chapter), and therefore the fall in the carbon intensity differential between France and other countries.

## Emissions from electricity imports are virtually zero

Emissions linked to the French power system can be assessed in relation to different scopes (see Figure 5.11): the electricity generated in France, detailed in the previous sections, but also the electricity consumed in France. As well as the proportion that covers the country's own consumption, part of the electricity produced in France is exported to other European countries. Conversely, part of France's

**Figure 5.9 – Emissions prevented by France's exports over the period 2017–2025**

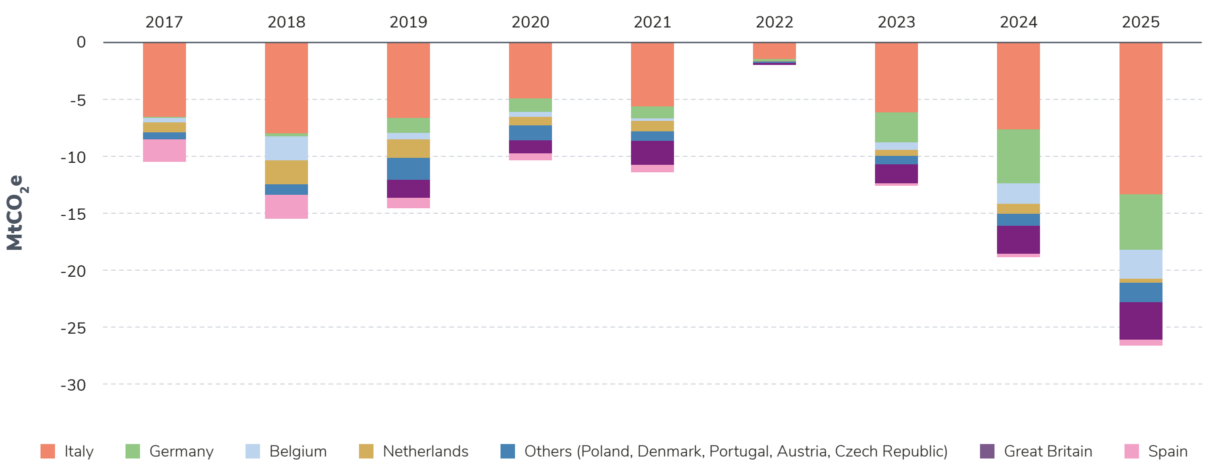
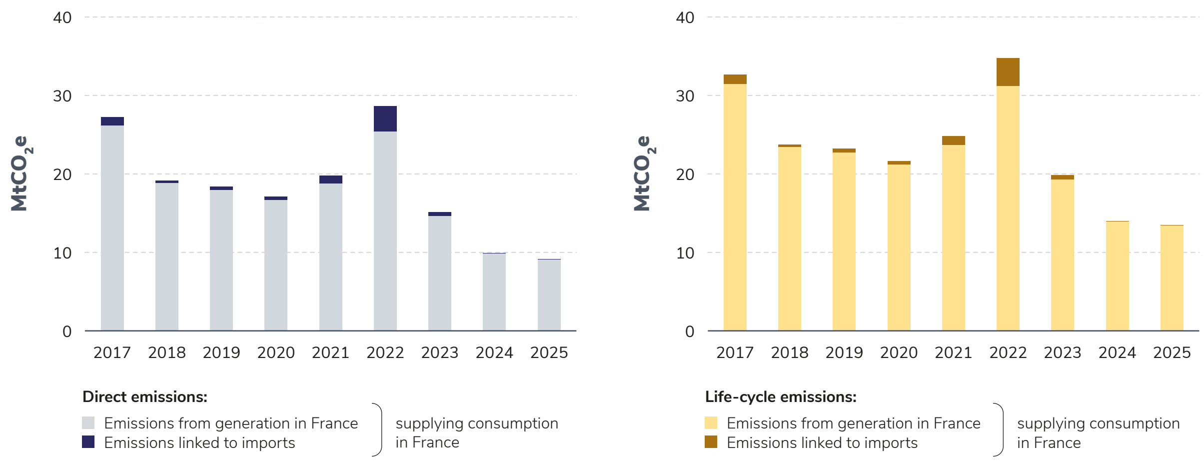


**Figure 5.10 – Greenhouse gas emissions related to electricity consumption in France between 2017 and 2025**




consumption is covered by imports of electricity generated abroad, particularly during high-consumption periods in winter, or when it is cheaper to import from neighbouring countries (particularly if there is abundant renewable generation in those countries) than to start up more expensive generating facilities in France.

In 2025, **the emissions arising from electricity imports that were actually used to supply French consumption were close to zero.** This is a direct consequence of the fact that the country was a net exporter almost 99% of the time.

**In addition, we estimate that around 17% of emissions from electricity generation in France were associated with volumes of electricity that were exported. Emissions linked strictly to French electricity consumption amounted to 9.1 MtCO$_2$e** (see Figure 5.1 above for a comparison of the orders of magnitude).

**Figure 5.11 – Summary of the concepts involved in the calculation of greenhouse gas emissions related to electricity**

| | | | Type of emissions | |
|---|---|---|---|---|
| | | | **Direct emissions** | **Life-cycle emissions** |
| | | | For electricity generated in fossil-fired power plants, these are emissions related to combustion. Electricity generation resources that do not use fossil fuels (wind, solar, nuclear and hydro power) do not generate direct emissions. | Life-cycle emissions assessment or LCA includes all the emissions generated to make a certain amount of electricity available: these include all the emissions related to the extraction and transport of materials used for the construction of power plants, equipment and infrastructure in France or abroad. These emissions can take place upstream or downstream of electricity generation facilities. Life cycle emissions include direct emissions. |
| Scope | Elec. gen. | This concerns the electricity generated by the facilities present on the national territory | Direct emissions from electricity generation plants located on the national territory. | Life-cycle emissions attributable to electricity generated on French territory. Some of the emissions related to earlier or later stages of the life cycle (excluding combustion) may take place abroad. |
| Scope | Electricity consumption | This concerns electricity consumed on French territory: this is the share of French generation that is not exported, as well as imports. | Direct emissions from electricity generation plants located on the national territory, minus emissions from the generation of exported electricity, and direct emissions from plants located abroad that supply electricity consumption in France (via imports). | Life-cycle emissions attributable to electricity consumed on French territory. Life-cycle emissions of electricity generated in France but exported are not counted; life-cycle emissions of imports that supply electricity consumption in France are counted. |

# Electrification of energy uses

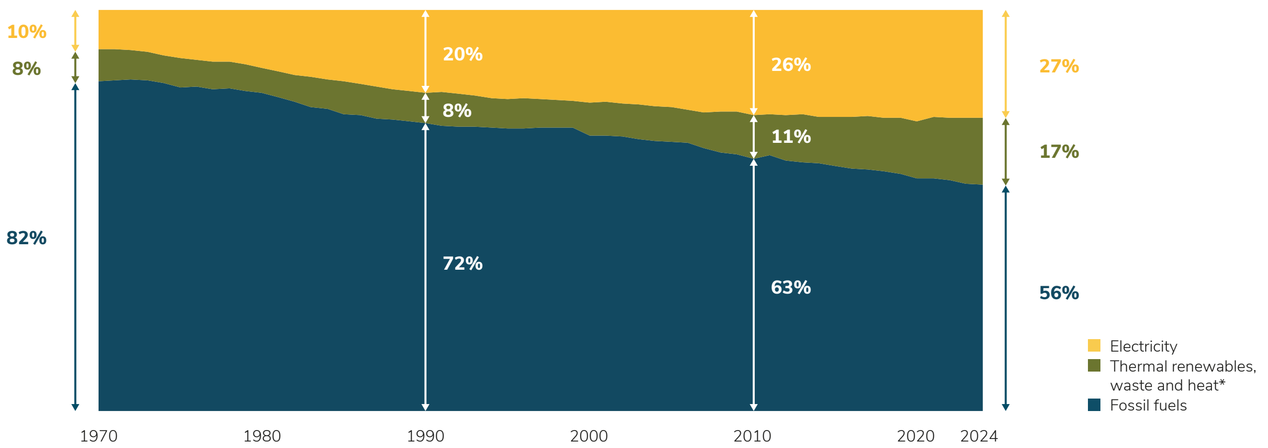
**2025 ELECTRICITY REVIEW**

## The ambition of reducing fossil fuel imports is now supported by a number of electrification projects that have already secured access to the grid for the coming years

**Fossil fuels (oil, gas, coal) continue to dominate final energy consumption in France: in 2024, they accounted for around 56% of the energy consumed in mainland France, while electricity accounted for just 27%[1].** This high level of fossil fuel consumption is responsible for most of the country's greenhouse gas emissions.

An analysis of historical data shows that electrification has followed different trends over different periods. At the end of the 20th century, electricity rose steadily as a proportion of final consumption from around 10% in 1970 to 26% in 2010, driven by the partial electrification of certain energy uses such as domestic hot water and heating. Since then, the rate of electrification of the economy has remained relatively stable.

**Figure 6.1 – Proportions of final consumption from different energy sources (not adjusted for weather or calendar effects)**




**Data source:** SDES – **Graph:** RTE

* *Heat included from 2000*

1. SDES, *Chiffres clés de l'énergie*, January 2026. Data adjusted for climatic variations. Electrification rate excludes non-energy uses of raw materials. The 2025 data was not available at the time of publication of the Electricity Review.

**While electrification should make it possible to support the switch from fossil fuels to low-carbon energy needed to achieve climate and energy sovereignty targets (see the analyses in the Generation Adequacy Report or *Energy Pathways to 2050*), recent trends show that this movement has not yet achieved real momentum.**

Looking at the detail, the share of electricity relative to fossil fuels varies significantly depending on the sector.

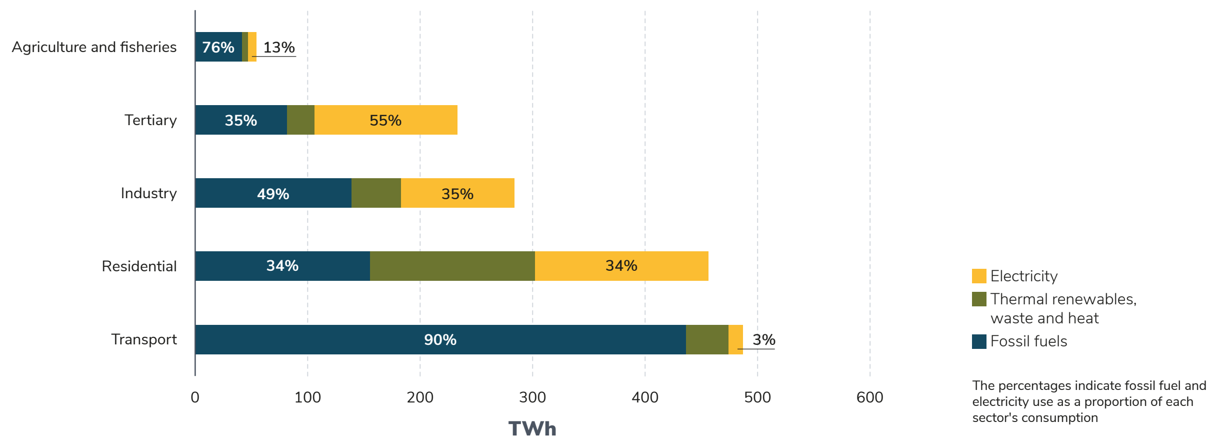
Transport is both the largest consumer of energy and the sector most dependent on fossil fuels, which account for almost 90% of its consumption.

Fossil fuels also represent a significant proportion of energy consumption in other sectors. For example, they still account for 34% of residential energy consumption, mainly for heating, domestic hot water and cooking. In industry, almost half of final energy consumption is supplied by fossil fuels. Lastly, the share of fossil fuels in the tertiary sector and agriculture is 35% and 76% respectively.

Because of its predominant consumption of fossil fuels, transport is by far the biggest emitter of greenhouse gases in France, accounting for more than a third (34%) of direct emissions[2]. In addition, this is the only sector in which emissions remained unchanged in 2024 compared with their 1990 level[3], whereas they fell in all other sectors. Next comes agriculture, with around 20.6% of emissions, followed by manufacturing industry and the construction sector (16.9%), residential and tertiary buildings (15.5%), the energy industry (9%) and waste management (4.2%).

**Only a small proportion of emissions are linked to electricity generation: around 10 $MtCO_2e$ in 2025, or approximately 3% of French emissions, since electricity is largely low-carbon (up to 95% in 2024 and 2025), unlike in other countries. The main challenge therefore lies in replacing fossil**

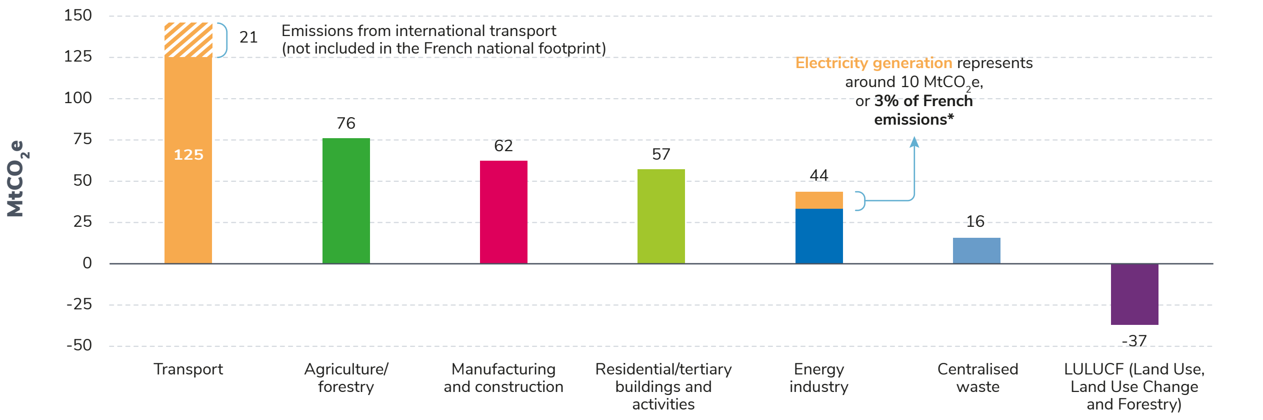
**Figure 6.2 – Climate-adjusted final energy consumption for energy use by sector in mainland France in 2024**




**Data source:** SDES – **Graph:** RTE

2. The share of emissions excludes the contribution of LULUCF (land use, land use change and forestry), which is negative.
3. Citepa – Secten, *Emissions de gaz à effet de serre et de polluants atmosphériques 1990–2024*, 2025

Figure 6.3 – Greenhouse gas emissions by economic sector in 2024 ($MtCO_2e$, excluding LULUCF)




**Data source:** CITEPA, 2025 SECTEN Report – **Graph:** RTE

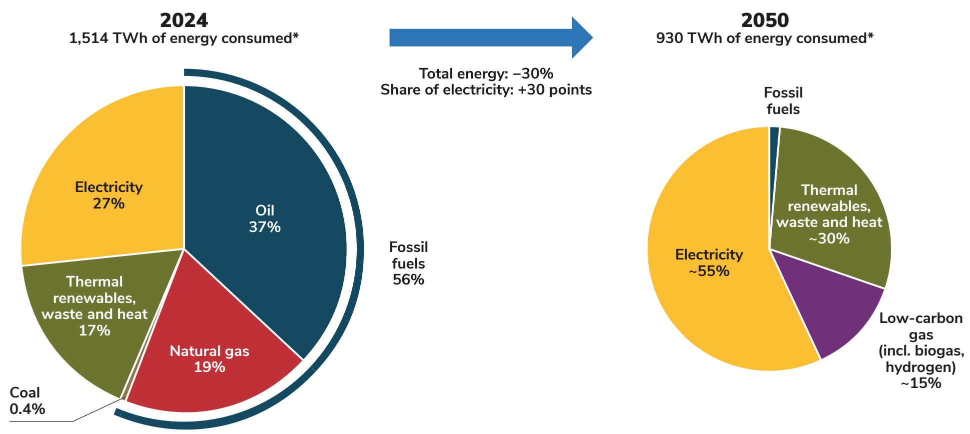
** Percentage calculated in relation to the national total with LULUCF used as a reference.*

**fuels in sectors other than electricity generation: electrifying these energy uses is a key means of achieving this, reducing dependence on fossil fuel imports and cutting emissions.**

France's decarbonisation strategy is based on a combination of reducing total energy consumption across all vectors (promoting energy efficiency and sufficiency) and switching to low-carbon energy sources, particularly through electrification, which can be deployed to decarbonise many energy uses very effectively. For some uses, electrification also provides major energy savings: an electric vehicle, for example, consumes around three times less energy than a car with an internal combustion engine, and the same is true of an electric heat pump compared with a gas or oil-fired boiler.

**Under the PPE multi-year energy plan published in February 2026, the electricity proportion of final energy consumption should reach 34% by 2030 and 38% by 2035, a pathway that is broadly**

Figure 6.4 – Proportions of final consumption from different energy sources




**Data source:** SDES and RTE (*Energy Pathways to 2050*)

**consistent with the rapid decarbonisation scenario presented by RTE in its 2025 Generation Adequacy Report.** The government has also announced a plan for the electrification of energy uses with the aim of establishing "*concrete proposals in the sectors of industry and crafts, digital, construction and mobility*"[4]. Electrification represents important leverage for achieving the decarbonisation targets, and is also included in the strategies of most other European countries.

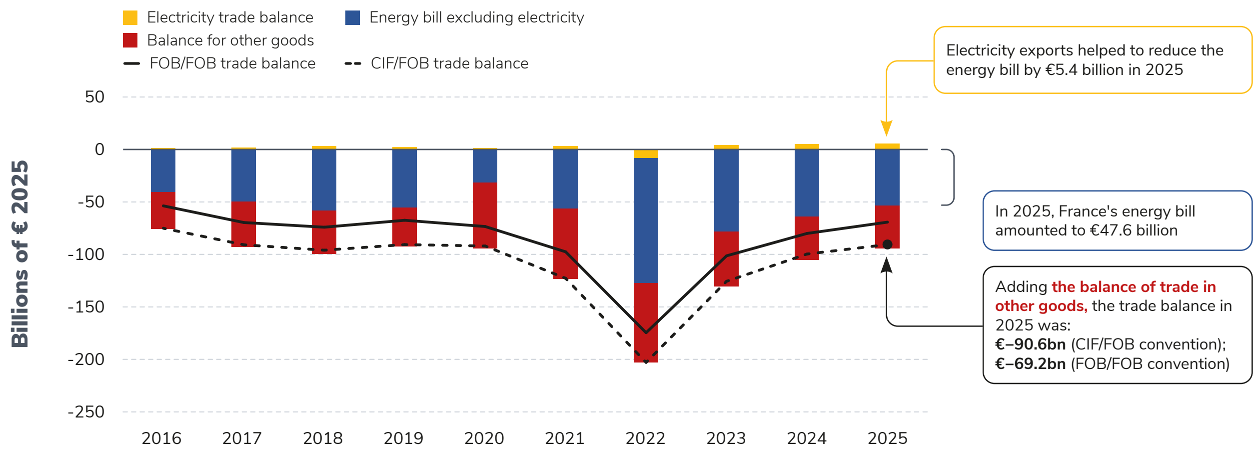
## Electrification represents an opportunity to strengthen France's energy sovereignty

France's energy bill, i.e. the difference between the value of the energy products imported and exported, shows a significant deficit: in 2025, it stood at around €47.6 billion, with €53 billion spent on fossil fuel imports. The majority of these come from non-European countries or countries in the former Soviet bloc (such as Azerbaijan, Georgia, Kazakhstan and Russia), which account for 57% of natural gas imports and 90% of crude oil imports. In 2024, for example, France imported 77 TWh of natural gas from Russia and 90 TWh from the United States[5].

**Energy products thus account for a major component[6] of France's trade deficit in goods** (€69.2bn in 2025[7]). This is not an exceptional situation: France's energy bill was between $€_{2025}$28 and 86 billion from 2009 to 2020 (with a peak of $€_{2025}$127 billion in 2022, at the height of the energy crisis)[8]. When France is a net exporter of electricity, as has been the case every year since the early 1980s except for 2022, the value of the electricity exported helps to reduce the energy bill, even though its scale (€5.4 billion in 2025, see the *Trading* chapter) remains limited compared with fossil fuels.

**Replacing fossil fuel consumption with electricity would thus reduce France's dependence on supplies from non-European countries in the strategic**

**Figure 6.5 – France's trade balance between 2016 and 2025, with a focus on energy**




**Data source:** Customs, INSEE and SDES. SDES data for the energy bill up to 2024 and customs data in 2025, for the same scope. **Graph:** RTE

4. Programmation Pluriannuelle de l'Énergie, February 2026.
5. SDES, *Chiffres clés de l'énergie*, January 2026
6. Customs data, RTE calculations. The aggregates used here are taken from the quarterly customs reports classification and include products AZ, B05-8Z, C1-C5, D, E, JZ, MN, RU.
7. Source: Customs, trade deficit in goods, FOB/FOB. The valuation of energy products is presented here using the CIF/FOB convention, since the correction from CIF/FOB to FOB/FOB is only available for the total.
8. See also the *Trading* chapter.

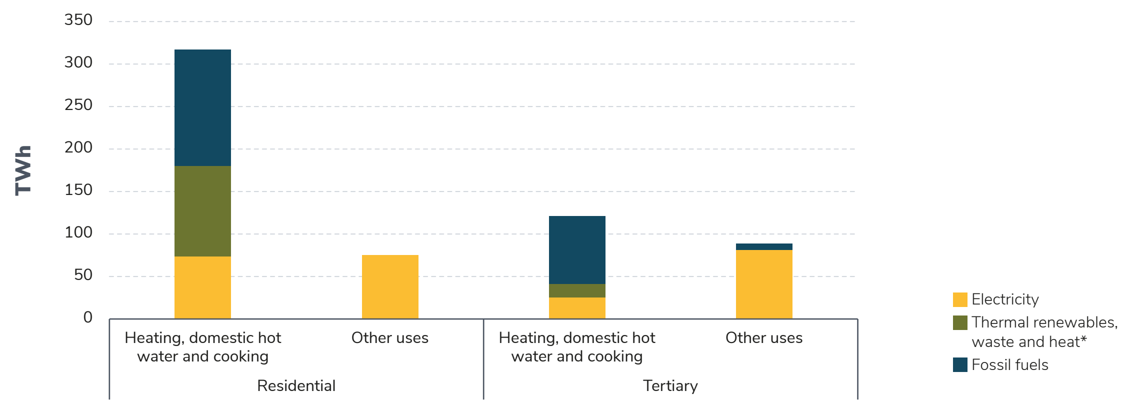
**field of energy, and reduce the trade deficit.** The choice of electrification is all the more relevant in that France already has abundant, largely low-carbon electricity, at lower prices than most other European countries (see the *Prices* chapter). RTE's latest future-focused analyses have identified a "*strategic situation (...) that is highly advantageous for rapidly decarbonising*" the French economy, "*without the risk of conflicts of use between the sectors to be electrified*"[9].

## Heating in homes and tertiary buildings is still largely dependent on fossil fuels

The rate of electrification of final energy consumption in buildings is 34% for homes and 55% for tertiary buildings. While some energy uses, such as ventilation and air conditioning, are already largely electrified, others, such as heating, are currently much less so. Despite a higher level of electrification than in other countries, fossil fuels accounted for 47% of residential heating energy consumption in 2024[10] (including 35% for natural gas and 11% for oil) and 68% of heating energy consumption in tertiary buildings. Electricity covers only 19% of residential heating needs, with the remainder covered by other sources such as wood burners or district heating networks.

As a result, emissions from homes and tertiary buildings arise mainly from the use of fossil fuels for heating[11]. Developing efficient electrical solutions, such as heat pumps, to replace fossil fuel boilers is therefore one of the key avenues for decarbonising the building stock.

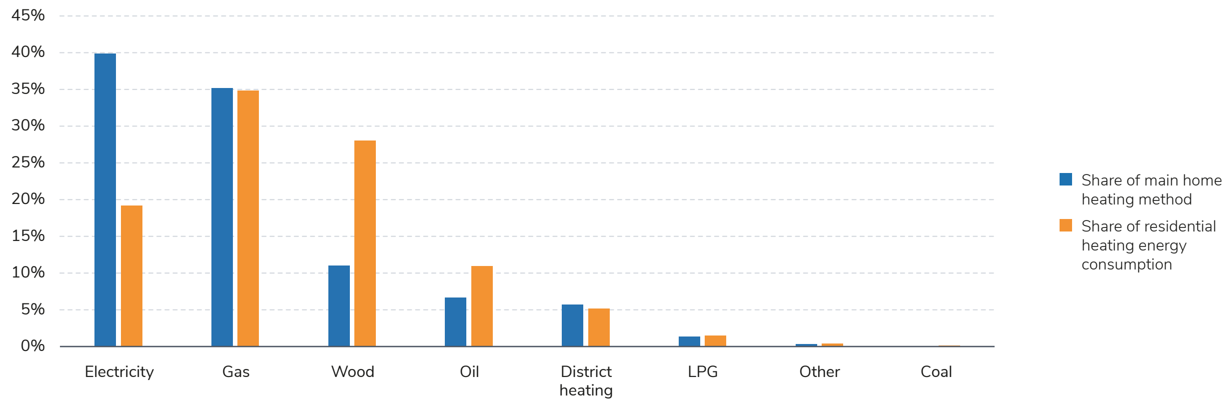
**Figure 6.6 – Energy consumption by use in the residential and tertiary sectors**




**Data source:** SDES. Data from 2023 for residential and 2020 for tertiary – **Graph:** RTE

9. RTE, *Bilan prévisionnel – Période 2025–2035*, 2025 edition
10. SDES data, "*Consommation d'énergie par usage du résidentiel*", 2025
11. CITEPA, "*Le rapport Secten édition 2025 vient d'être publié*", 2025

**Figure 6.7 – Main home heating energy sources and their shares of residential heating energy consumption in 2024**




**Data source:** CEREN – **Graph:** RTE

## Sales of heat pumps have fallen since 2024

The main source of energy used for heating in residential and tertiary buildings depends essentially on when they were built. The choice depends on the infrastructure available (such as district heating or gas networks), the technical solutions that exist, their relative prices and the regulations in force.

Historically, heating has already undergone two waves of electrification[12]. The first was during the 1970s and 1980s, in parallel with the development of civil nuclear power in France, and was based mainly on Joule electric heating. The second came in the 2000s, when rising fossil fuel prices led to a switch to electric heating. During these two periods, the proportion of electric heating in new homes rose to over 50%.

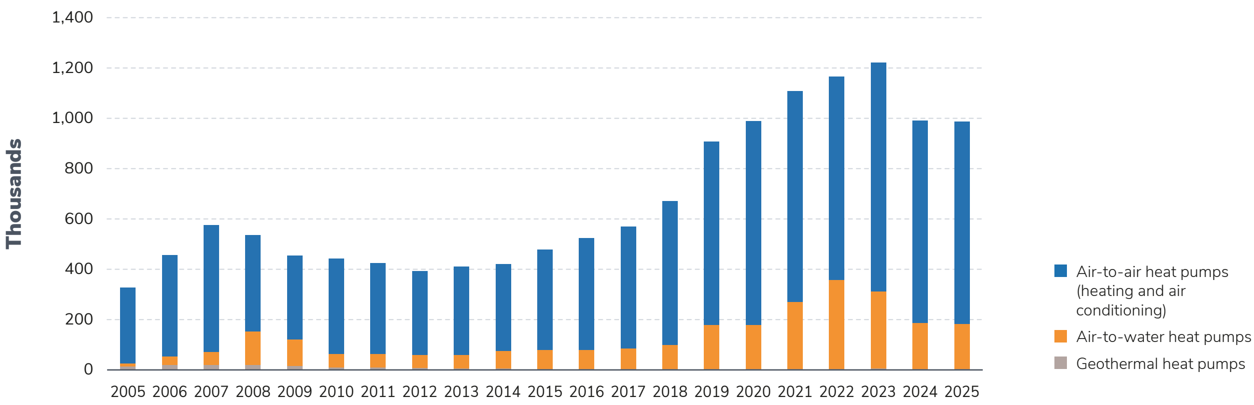
**Given the inertia in the development of heating methods in the building sector, these waves of electrification are still reflected in the composition of the heating stock today: around a third of homes (32% in 2020) are currently equipped with Joule electric heating.**

After 2010, the electrification of heating was mainly driven by the development of heat pumps, particularly in new homes. From a very low level of development in the early 2000s, their consumption for heating homes exceeded 10 TWh[13] in 2023 and they now account for just under 3% of energy consumption in residential buildings. By 2024, electric heat pumps were the main heating system in around 10% of primary homes.

Yet **since 2024, the growth trend of the past fifteen years has stalled.** In fact, 2024 saw a significant drop in heat pump sales, with around one million units sold[14], 200,000 fewer than the previous year. **In 2025, heat pump sales remained stable compared with the previous year[15].**

12. SDES, "*Les énergies de chauffage des ménages en France métropolitaine*", 2024
13. SDES data, "*Consommation d'énergie par usage du résidentiel*", 2025
14. Of these million units, around 800,000 were air-to-air heat pumps that can be used for both heating and cooling.
15. Uniclima, "*Bilan 2025 du marché du génie climatique et perspectives*", 2026

**Figure 6.8 – Number of heat pumps sold between 2005 and 2025**




**Data source:** SDES from 2005 to 2024, Uniclima for 2025 – **Graph:** RTE

**The pattern that has been seen since 2024 is partly due to a decline in new house building: 274,600 new homes were begun in 2025, which is 21.3% lower than the average for the previous five years.** And although the number of homes receiving planning permission in 2025 (379,000[16]) was up on 2024 (+14%), this figure is still 8.8% below the average for the previous five years.

## The total number of thermal renovations is down, but the number of major renovations is up

The housing stock is characterised by a high level of inertia: several hundred thousand units are built every year, but the stock of main residences amounts to several tens of millions of homes (38.4 million as of 1 January 2025).

**These orders of magnitude highlight the benefits of renovating existing homes, and particularly replacing heating systems, to reduce both their fossil fuel energy consumption and their greenhouse gas emissions.**

As of 1 January 2025, the most common energy performance certificate (EPC) rating used in the housing stock was "D". The worst-performing homes, rated F and G (often referred to in France as "heat sieves") still accounted for 3.9 million primary residences[17] (around 12.7% of the housing stock) in 2025, and these are the priority targets for thermal renovation policies. The proportion of these homes in the housing stock fell in 2025: around 327,000 fewer homes, or 1.2 percentage points less as a share of the stock.

The government currently supports heating and insulation upgrades primarily through the MaPrimeRenov' scheme. This system helps to finance part of the renovation work, whether this is a single action, such as changing the heating system or insulating the building, or a "major renovation", the most effective type of upgrade, with tailored support.

16. SDES, "*Stat info Logements N° 791: Construction de logements – résultats à fin décembre 2025*", January 2026
17. As of 1 January 2026, the conversion factor from final energy to primary energy for electricity has been reduced from 2.3 to 1.9, which – among other effects – will result in a number of these homes no longer being classed as "heat sieves" and, in the longer term, will favour electric heating over other, more carbon-intensive heating methods.

The MaPrimeRenov' scheme was temporarily suspended during the 2025–2026 budget cycle, meaning that the data made available by ANAH, the national housing agency, for 2025 stops in the third quarter. It was reopened when the 2026 finance act was adopted and has a budget of €3.6 billion for this year (€3.4 billion in 2025), which should make it possible to *finance at least 120,000 major renovations and 150,000 individual upgrades*[18].

Since 2024, ANAH has been favouring larger-scale renovations more than in the past, which partly explains the discontinuity in the number of homes renovated – fewer than before 2024 (226,000[19] homes at the end of Q3 25) – and in the grant amounts awarded, which are up significantly (€2.7 billion at the end of Q3 2025 compared with €1.85 billion at the end of Q3 2024). Relative to the same period in 2024, the number of renovations remained stable, but larger-scale, more substantial and more effective renovations were carried out in 77,650 homes, compared with 42,700 in 2024. These projects now account for 82% of the funds granted, compared with 60% the previous year.

18. france Renov', *MaPrimeRénov' : réouverture du guichet à la promulgation de la loi de finances*, 2026
19. The figures presented here stop at the third quarter of 2025 as the ANAH scheme is currently suspended pending the adoption of the 2026 Finance Bill.

# Electric mobility is continuing to develop, but fossil fuels still account for 90% of energy consumption for transport

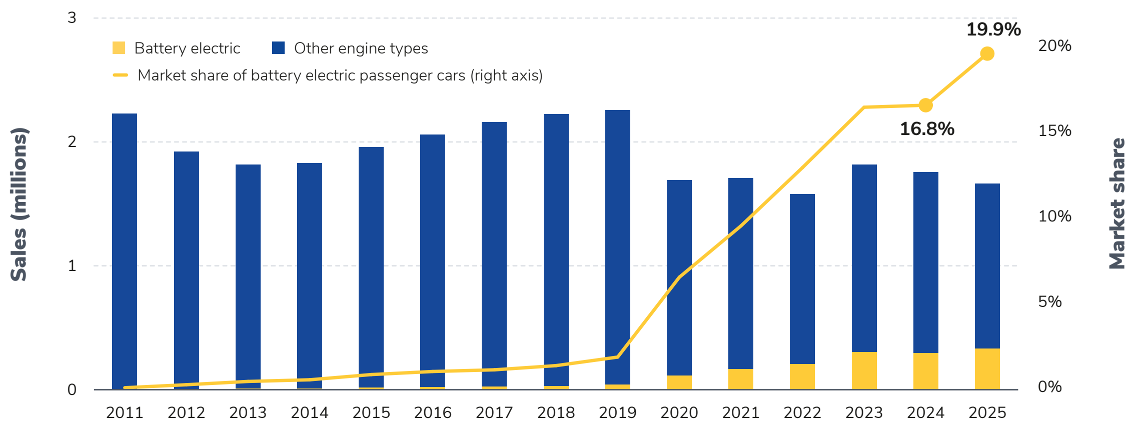
The transport sector is both the biggest consumer of final energy (one third of French final energy consumption) and the biggest emitter of greenhouse gases (one third of greenhouse gas emissions) in France. Within the sector, road passenger and freight transport, fuelled largely by petroleum products, is responsible for the bulk of energy consumption and consequently greenhouse gas emissions (53% for private vehicles, 22% for HGVs, 15% for light commercial vehicles[20]).

The development of electric vehicles is one of the main ways in which fossil fuels can be effectively replaced in transport, and particularly road transport. France's car fleet consists of almost 43 million light vehicles (passenger cars and light commercial vehicles), including 1.7 million battery electric vehicles (as of the end of 2025)[21]. In addition, there are 850,000 plug-in hybrid vehicles, which use both fossil fuels and electricity.

## Sales of electric vehicles have resumed their upward trend but need to accelerate further to meet government targets

In 2025, sales of battery electric passenger vehicles exceeded 330,000 units, the highest volume ever achieved in France[22]. This represents an increase of 12% on the previous year, despite the reduction in purchase subsidies during 2025. Their market share increased to almost 20%, up from 16.8% in 2024: **in 2025, one in five passenger cars sold was a battery electric vehicle.**

**Figure 6.9 – Sales of new battery electric cars in France between 2011 and 2025**




**Data source:** SDES – **Graph:** RTE

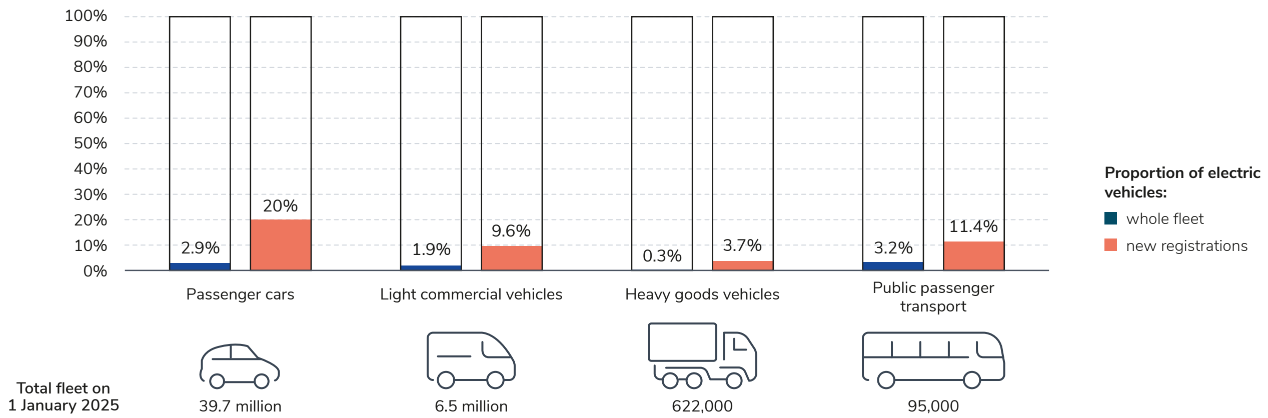
20. SDES, *Bilan annuel des transports en 2024 | Données et études statistiques*, November 2025
21. Avere-France, *[Baromètre] Décembre 2025 : les véhicules 100 % électriques signent un mois record à 46 282 immatriculations !*, January 2026
22. Scope: all of France

Since 2011, sales of these vehicles have grown steadily every year in France, except for 2024 when they stabilised, while the car market as a whole has been slowing since 2024. At the end of 2025, the fleet of battery electric passenger cars had reached 1.5 million units. In addition, there were 825,000 hybrid cars, compared with 1.2 million battery electric cars and 721,000 hybrid cars in 2024.

Electricity consumption by passenger vehicles (battery electric and plug-in hybrids) was about 4 TWh in 2025, an increase of 33% on the previous year[23]. This represents around 6% of the passenger car fleet, with a renewal rate of around 5% per year.

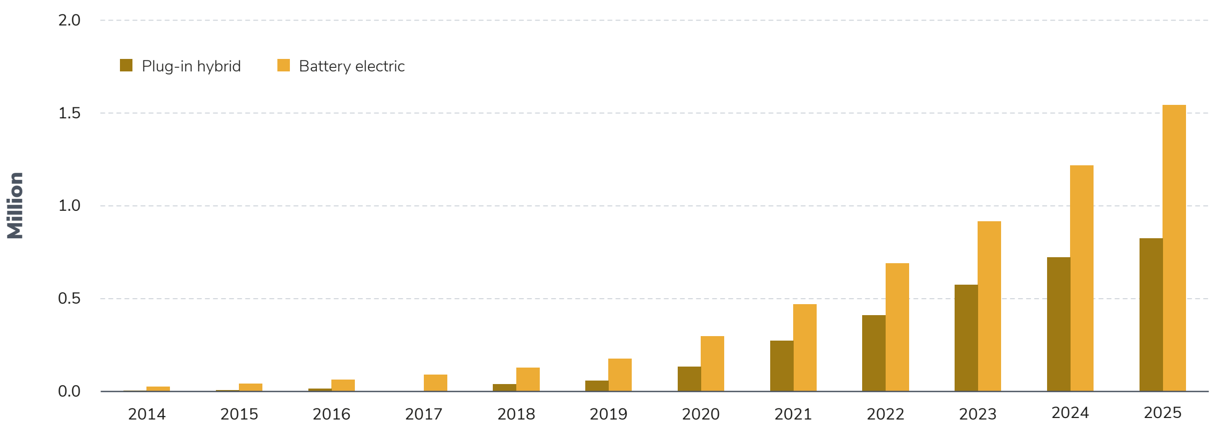
The trend for other categories of electric vehicle is also positive. The number of registrations of light

**Figure 6.10 – Battery electric vehicles as a proportion of the whole fleet and of new registrations**




**Data sources:** total fleet: SDES; EV sales: Avere-France/AAAData; total sales: European Alternative Fuels Observatory – **Calculations and graph:** RTE
The fleet is given as of 1 January 2025; sales correspond to the year 2025.

**Figure 6.11 – Growth in the number of battery electric and plug-in hybrid passenger cars between 2014 and 2025**




**Data source:** European Alternative Fuels Observatory

23. This is an estimate based on the vehicle fleet and assumptions about mileage and electricity consumption.

commercial vehicles, public passenger transport vehicles and battery electric heavy goods vehicles increased by 28%, 8% and 39% respectively[24] between 2024 and 2025.

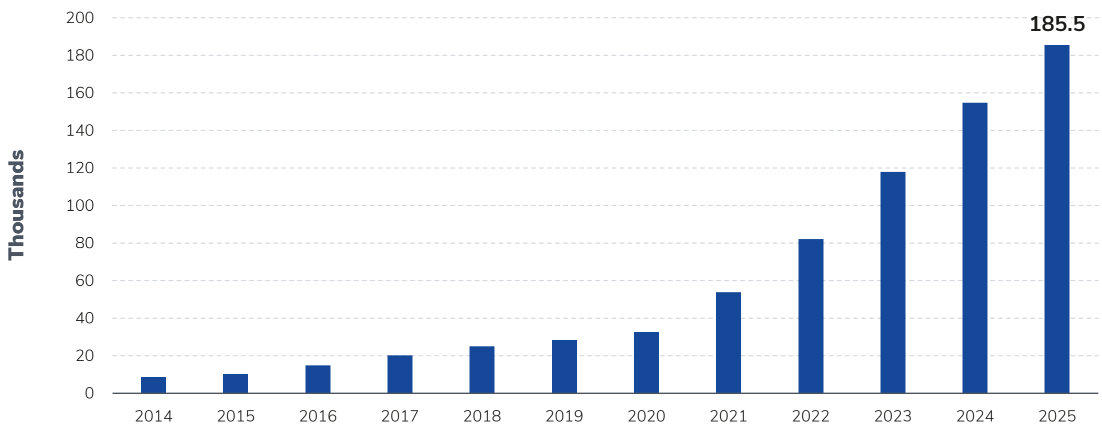
Electrification is less advanced in these segments than for passenger cars, but is growing rapidly: battery electric vehicles accounted for 9.6%, 11.4% and 3.7% respectively of new registrations in 2025 in the three categories. However, these vehicles are still a minority of the existing fleet.

The effect of the rise in sales of electric vehicles can be seen in the average greenhouse gas emissions of new vehicles, which have been falling steadily since 2020. They have dropped from 111 g/km in 2020 to 83 g/km for passenger cars and from 177 g/km to 163 g/km for light commercial vehicles. Not all of this reduction is attributable to electric vehicles alone, however – part of it comes from the improved efficiency of internal combustion engines.

## The development of charging infrastructure remains dynamic despite a slowdown in 2025

The development of charging infrastructure continued in 2025 with the installation of nearly 31,000[25] public charging stations, an increase of 20%, amounting to a total of 185,500 stations. The upward trend remains strong despite a slowdown in the rate at which the number of installations is increasing, averaging +48% per year between 2021 and 2024.

**Figure 6.12 – Number of charging points open to the public over time in France**




**Data source:** Avere-France

24. CCFA/AAA-DATA, Immatriculations mensuelles par énergie
25. Avere-France

# The electrification of energy uses is an opportunity for French industry, but one that is proving slow to materialise

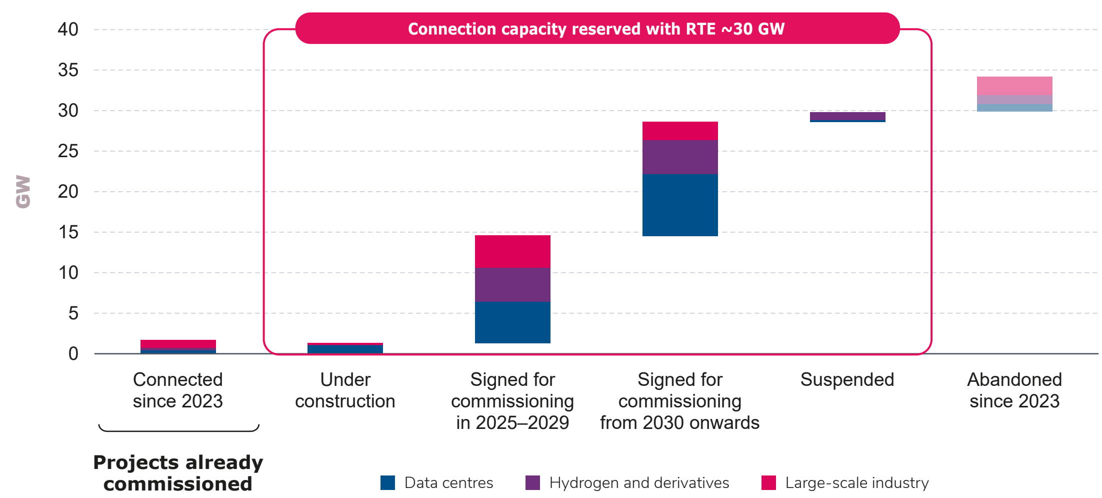
Industry accounted for 17% of greenhouse gases emissions in France in 2024[26]. Energy-intensive activities (chemicals, metallurgy, iron and steel, agri-food, wood, paper, rubber, plastic and glass manufacturing) are the biggest emitters of greenhouse gases overall. Industry still largely derives its energy from fossil fuels, with natural gas chief among them, though its share is gradually declining – from 63% in 1990 to 48% in 2024, thanks partly to the use of bioenergy and district heating networks.

**In contrast, electricity's share of final energy consumption in the industrial sector has risen only slightly over the last 25 years, from 32% in 1990 to 36% in 2024.**

Final electricity consumption in industry has been on a downward trend for almost two decades in France, as has final energy consumption across all energy vectors. This trend reflects the effect of energy efficiency measures, which have been widely developed in this sector over the last few decades, as well as the decline in activity in the electricity-intensive sectors, though this came to a halt in the 2010s. Over the last fifteen years, manufacturing's share of GDP has broadly stabilised at around 10% (compared with 16% in 2000).

**As highlighted in the 2025 Generation Adequacy Report, over 170 major industrial and digital projects are currently under development to contribute to decarbonising existing industrial sites, reindustrialisation and digital sovereignty.** Although the effects on industrial consumption are not yet visible, many electrification projects and new industrial sites have been granted access rights to the electricity transmission network. By 1 November 2025, they had reached around 30 GW, including 14 GW for data centres, 9.5 GW for hydrogen production units and 6.5 GW for electrification projects at existing or new industrial sites.

**Figure 6.13 – Breakdown of transmission system access rights by status (situation at end of November 2025)**




26. Citepa – Secten, *Émissions de gaz à effet de serre et de polluants atmosphériques 1990-2024*, 2025

Around half of this 30 GW figure involves projects scheduled to come on stream between 2025 and 2029, which should lead to an increase in consumption in the coming years, though this is difficult to estimate accurately because of uncertainty about the speed with which projects will be completed and scaled up. These requests are not binding, and RTE has no information on the level of maturity or progress of the projects being developed by the applicants. The system now needs to be redesigned to identify the sectors in which projects will operate, in order to maximise the chances of industrial projects becoming a reality, in line with the framework set out in the CRE's decision of 23 July 2025.

In terms of concrete achievements, the first major hydrogen project was connected to the RTE network in autumn 2025. This is the Normand'Hy project, led by the Air Liquide group in Port-Jérôme-sur-Seine, which will produce low-carbon hydrogen by electrolysis, decarbonising the hydrogen used by Total Energies' Normandy refinery located nearby. The project is scheduled to enter operational service in 2026.

In manufacturing, the Alteo group in Gardanne has replaced a gas-fired boiler with an electric equivalent (8 MW) for alumina production, electric kilns have been installed in the glass-making sector (at Verallia in Cognac and the Pochet group in Seine-Maritime), and in metallurgy Saint-Gobain PAM's Vulcain project has replaced a coal-fired cupola furnace at Foug in Meurthe-et-Moselle with a 20 MW electric furnace. Finally, a high-temperature industrial heat pump demonstrator has been set up in the paper industry, in the form of WEPA Greenfield's TransPAC project in Château-Thierry.

Support schemes exist to facilitate and assist investment in decarbonisation projects involving the electrification of energy uses, as these often require high levels of investment. One of the existing schemes is the France 2030 investment programme[27], which is helping to finance the Major Industrial Decarbonisation Projects call for bids (AO GPID) managed by ADEME[28]. This call for bids provides support for the largest industrial decarbonisation projects, backing the winners over a 15-year period. In the first round, seven projects were selected that will avoid 3.8 $MtCO_2e$/year, 24% of the national industrial emissions to be cut by 2030, with a budget of €1.6 billion. Two of these projects aim to replace equipment running on fossil fuels: one with an electric boiler, the other with a furnace fuelled by green hydrogen. There are also schemes at European level, such as the European Innovation Fund dedicated to reducing greenhouse gas emissions[29].

**France's abundant generation of competitive low-carbon electricity is now an asset that can strengthen France's energy sovereignty and reduce the burden of fossil fuel imports on the balance of trade by developing these new energy uses. Speeding up the implementation of this type of project is now essential.**

27. Ministère de l'économie, France 2030 : un plan d'investissement pour la France, October 2023
28. DGE, *Industrie décarbonée, industrie compétitive : point d'étape sur l'action de l'État*, February 2026
29. DGE, *Fonds pour l'innovation européen : 14 projets lauréats pour la France*, November 2025

# Europe

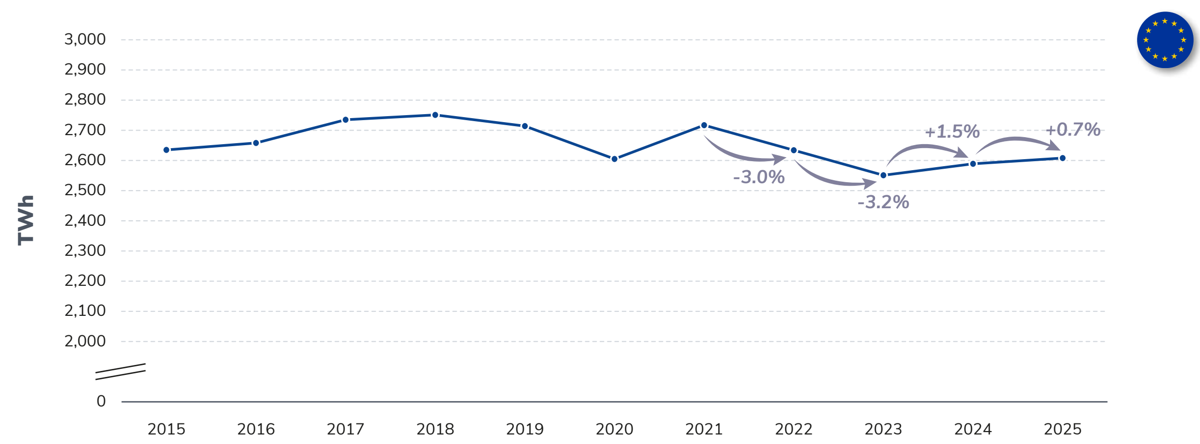
**2025 ELECTRICITY REVIEW**

## European electricity consumption remained stable in 2025 after bouncing back in 2024

**Gross electricity consumption, i.e. not adjusted for weather and calendar effects, remained relatively stable[1] in 2025 (+0.7%) across the European Union[2] compared with the previous year.**

After two years of sharp falls (–3.0% and –3.2%) in 2022 and 2023 due to the energy crisis and warmer winters, European consumption bounced back slightly in 2024 (+1.5%), but remained below the consumption levels before the pandemic and the energy crisis. This was also the case in 2025, with consumption remaining 3.4% lower than the average level between 2015 and 2019.

**Figure 7.1 – Gross electricity consumption (i.e. not adjusted for weather and calendar effects) in Europe (scope: EU-27)**




**Data source:** Eurostat, ENTSO-E – **Calculations:** RTE

1. The analysis in based on consumption not adjusted for weather and calendar effects, as consumption data adjusted for these effects is not available for other European countries. As 2024 was a leap year, the increase between 2023 and 2024 would have been slightly lower without this effect (+1.2%) and slightly higher between 2024 and 2025 (+1.0%).
2. The scope considered here is the European Union of 27 member states. The United Kingdom is not included, even in the pre-Brexit years, in order to maintain a constant scope and facilitate analysis.

**This stability of consumption at relatively low levels confirms that the drivers of the fall in demand in previous years in Europe have persisted in the short term, and particularly the effects of energy efficiency and energy sufficiency initiatives as well as the drop in industrial production in several countries, partly due to the global macroeconomic context.**

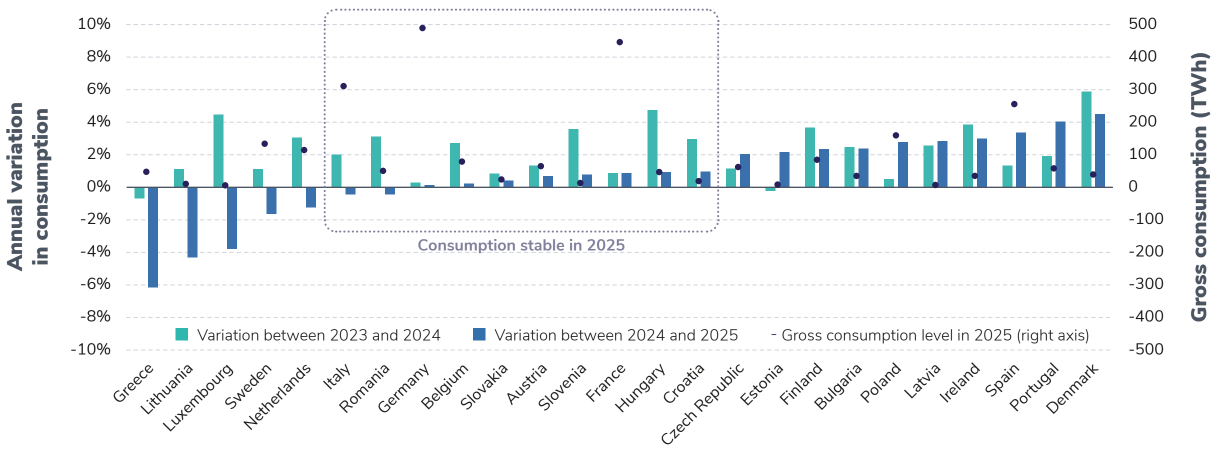
**For the time being, the effects of electrification remain hardly visible, despite (still-limited) progress in electrification rates in some countries.** Electrification is a key component of many European countries' medium-term strategies for reducing their reliance on fossil fuels. In certain scenarios[3], for example, Germany could see its consumption rise by almost 80% over the next 10 years, and Spain and the UK by almost 45%.

**The changes in consumption in 2025 were fairly mixed across the different countries, and less significant than those in 2024 compared with 2023. In the three biggest consumer countries (Germany, France and Italy), consumption remained relatively stable between 2024 and 2025.**

**However, some countries stand out from the general trend. In Greece, the sharp drop in consumption (–6% compared with 2024) was concentrated in June, July and August** (–13% on average compared with the same months the previous year). Greece is the hottest country in the EU, particularly in summer, so use of air conditioning there is significant. The summer of 2024 was the hottest on record, with an average temperature of 27.7°C. The summer of 2025 was slightly cooler, so electricity consumption in Greece was lower between June and August 2025 than the previous year, with a marked effect on annual consumption.

Conversely, Denmark was the country with the biggest increase in consumption in 2024 (+6%) and 2025 (+5%). It is also one of the European Union countries where the pace of electrification has increased the most over the last ten years (+7 points[4], against an average of +3 points in the EU-27), indicating the structural nature of this increase in consumption. The rise of electricity as a proportion of final energy consumption can be seen in all sectors, including the development of electric vehicles (Denmark is the EU country with the highest rate

**Figure 7.2 – Gross electricity consumption (i.e. not adjusted for weather and calendar effects) by country in Europe**



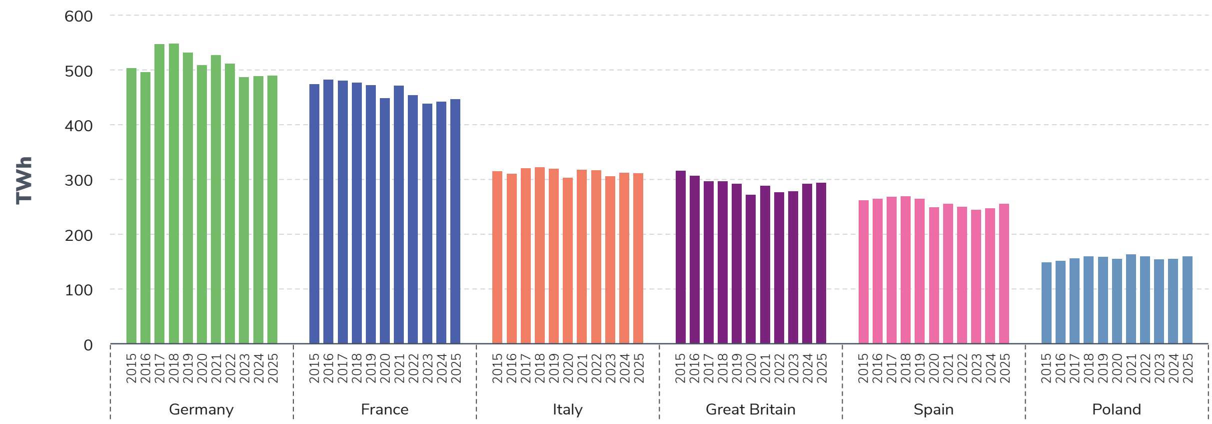

*Consumption is considered stable if its absolute variation from one year to the next is less than 1%*

3. Germany: BNetzA, Spain: ERAA24, Great Britain: FES2024
4. Source: Our World in Data, variation between 2015 and 2024
5. European Commission, *European Alternative Fuels Observatory*, 2024

of electric vehicle ownership[5]), the increased use of heat pumps in housing and the development of data centres[6]. Denmark was also the EU country with the strongest growth in industrial production in 2024 and 2025, which has also contributed to the upward trend in electricity consumption.

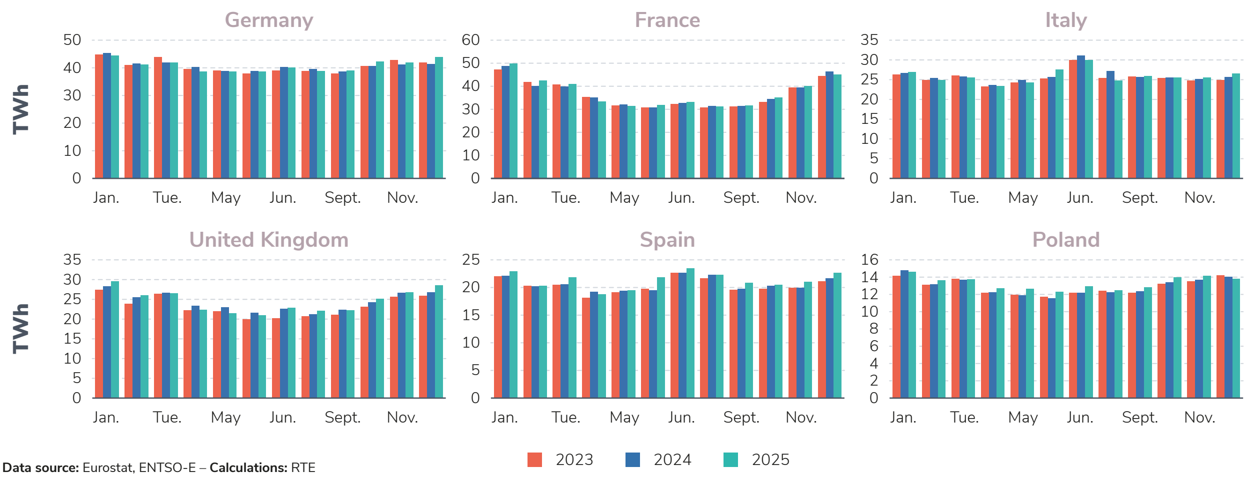
**After a slight increase in 2024, Spanish consumption rose by 3% in 2025.** A large part of this increase was concentrated in March and June. March 2025 was the wettest month since 2018[7], resulting in higher humidity and a drop in mid-month temperatures of three to four degrees compared to March 2024, resulting in an increased need for energy for heating. June 2025 was the hottest June on record in Spain, at 0.8°C above the previous record set in 2017[8], and even exceeded average July–August temperatures. Against this backdrop, consumption rose by 2.4 TWh in June compared with the same month the year before, representing almost a third of the increase in Spanish consumption over the year.

**Figure 7.3 – Gross electricity consumption (i.e. not adjusted for weather and calendar effects) in Europe's six largest consumer countries**




**Data source:** Eurostat, ENTSO-E, National Grid – **Calculations:** RTE

**Figure 7.4 – Gross monthly electricity consumption (i.e. not adjusted for weather and calendar effects) in Europe's six largest consumer countries**




**Data source:** Eurostat, ENTSO-E – **Calculations:** RTE

6. Energistyrelsen, *Årlig energistatistik*, 2024
7. Euronews, *Heavy rainfall fills empty reservoirs in Spain, bringing drought relief and floods*, 2025
8. Miteco, *Junio de 2025 fue el mes anómalamente cálido en España desde que hay registros*, 2025

**The decrease or stagnation in consumption in some countries in recent years can be attributed in part to the decline in industrial production.**

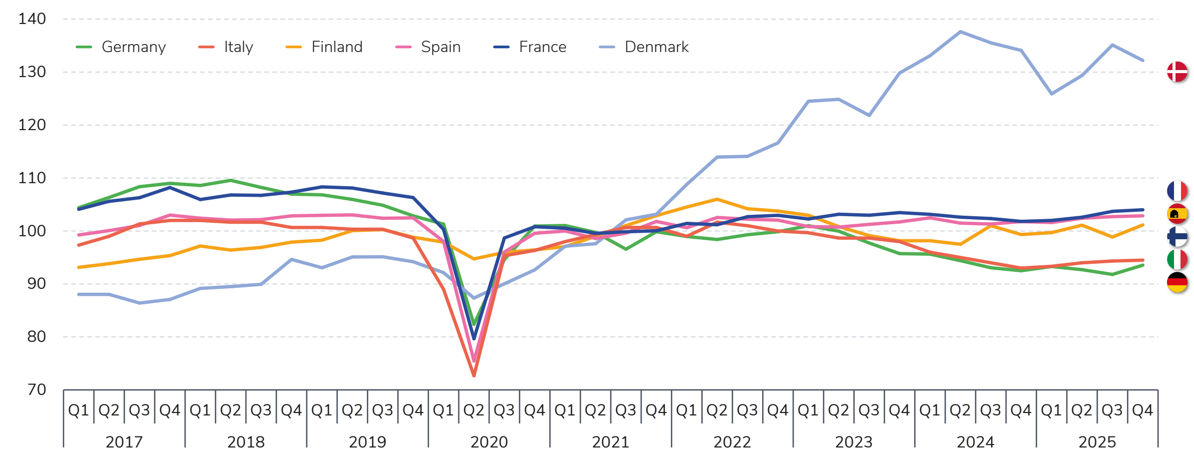
Among these countries, Germany and Italy are the EU's two largest industrial producers, accounting for around 45% of its total manufacturing output. They are also among the countries whose industrial production recorded the sharpest falls in 2024, followed by a slight recovery during 2025 for Italy. In Germany, industrial production continued its decline over 2025, despite an inversion of the trend in the fourth quarter. This fall reflected particularly high electricity prices compared with competitor countries, especially for energy-intensive sectors such as the automotive and steel industries, under the lingering effects of the 2022 energy crisis. The German government is considering a plan to subsidise electricity prices for these sectors from 2026 until 2028[9].

In general, temperatures were lower at the start of 2025 than at the same time in 2024. While this difference led to a one-off increase in consumption in France and Spain, its effect on consumption was less visible in other countries, where the other factors mentioned had a predominant effect.

**Electricity consumption in European countries has historically been temperature-sensitive, to varying degrees,** driven by the use of electric heating in autumn and winter and air conditioning in summer. While all European countries experience temperature sensitivity in winter, this is currently more pronounced in France than in other countries, including countries with colder winters such as Germany, due to the greater use of electric heating. For example, French consumption in January, February and March is around 20% higher than in other months, compared with less than 10% in Germany. The difference is particularly marked in January, the coldest month of the year, when consumption levels in France are generally the highest of the year.

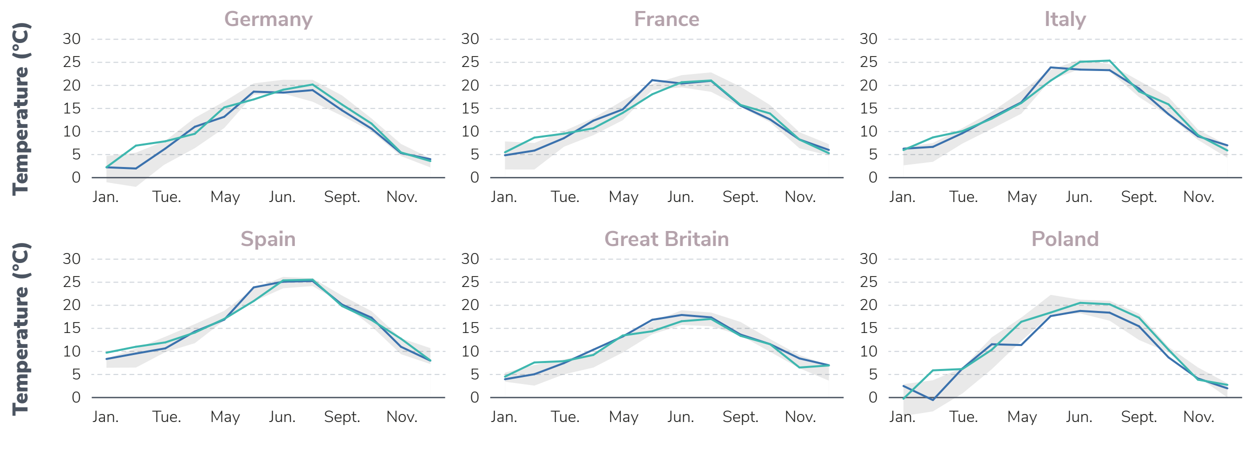
Conversely, in other countries such as Spain and Italy, electric heating is less common due to the relatively high proportion of fossil-fired electricity generation in the electricity mix between 1970 and 2000 (when heating was electrified on a large scale in France), which made the use of electric heating less attractive. These countries have historically favoured gas or oil-fired heating. In these two countries, electricity consumption from January to March is therefore relatively similar to other months (+4% on average for Spain and +1% for Italy). Conversely, consumption peaks in July, one of the hottest months of the year, when it is significantly higher than in other months (+10% on average in Spain, +18% in Italy). Consumption in August is lower than in June, mainly because of the drop in economic activity due to the summer holidays.

**Figure 7.5 – Quarterly breakdown of the industrial production index for a selection of European countries (base 100 in 2021, adjusted for calendar and seasonal effects)**




9. France24, *German plans to lower industrial power costs from January*, November 2025

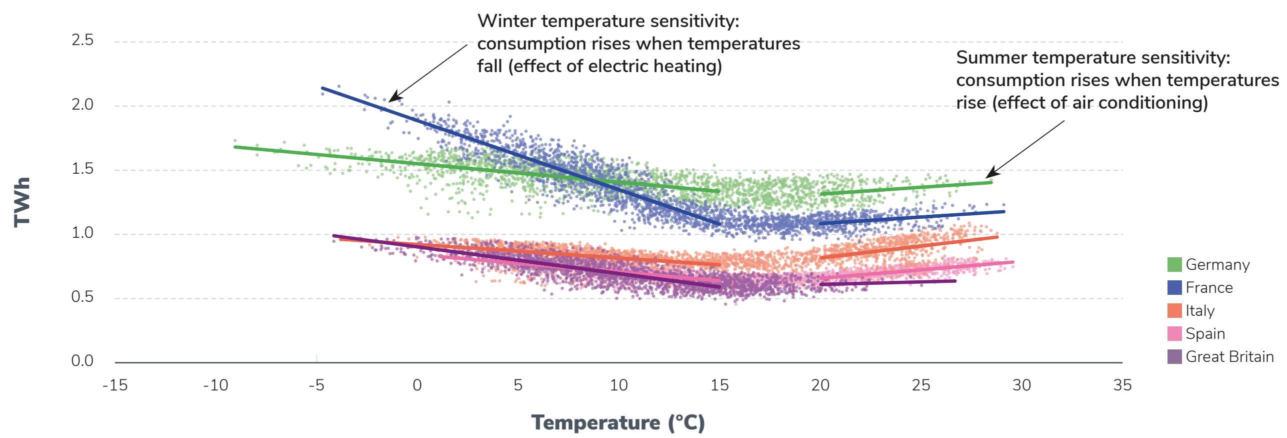
**Figure 7.6 – Temperature adjusted for population for Europe's six largest consumer countries**




**Data source:** ERA 5 TAW

The increase in consumption for each degree lost at low temperatures has remained almost constant over the last ten years in the countries analysed (the five countries with the highest consumption). Although electric heat pumps are beginning to gain ground, they are mainly installed in new, well-insulated buildings and thus have a limited impact on winter consumption. In the medium term, however, the development of electric heat pumps needs to accelerate in order to meet climate targets, and should also affect older homes (through renovation efforts), which could ultimately contribute to increasing the temperature sensitivity of electricity consumption in winter in many European countries.

**Figure 7.7 – Daily consumption according to temperature for a selection of European countries between 2017 and 2025 (working days only)**




**Data source:** ECMWF ERA5 Reanalysis, ENTSO-E, RTE – **Graph:** RTE

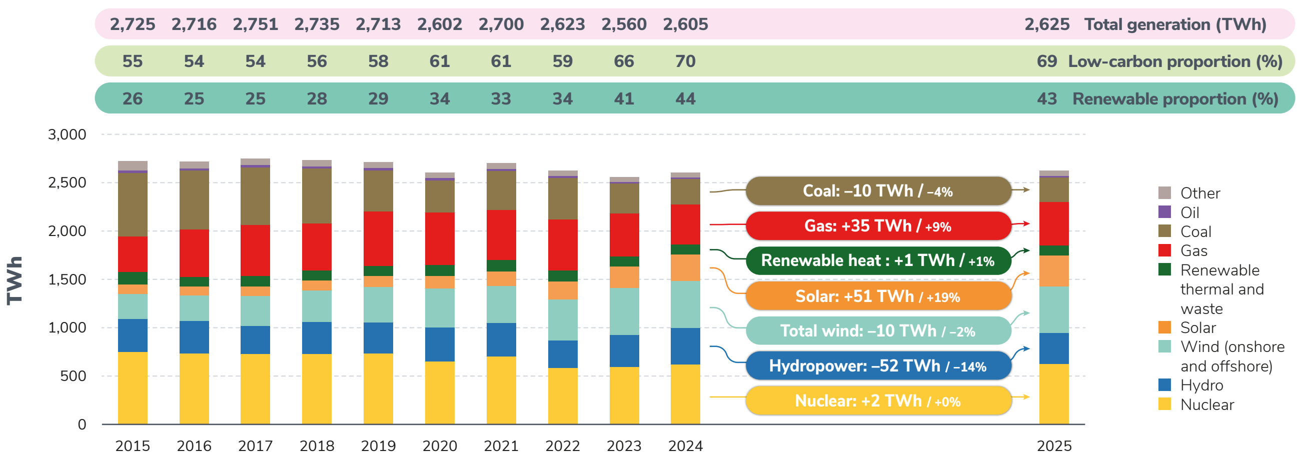
# Total electricity generation remained stable in Europe, with solar and wind production outstripping fossil fuel output for the second year running

**In line with the stagnation in electricity consumption, the volume of electricity generated within the European Union also remained relatively stable in 2025 compared with 2024 (+0.8%, +20 TWh),** though with marked variations across the energy mix.

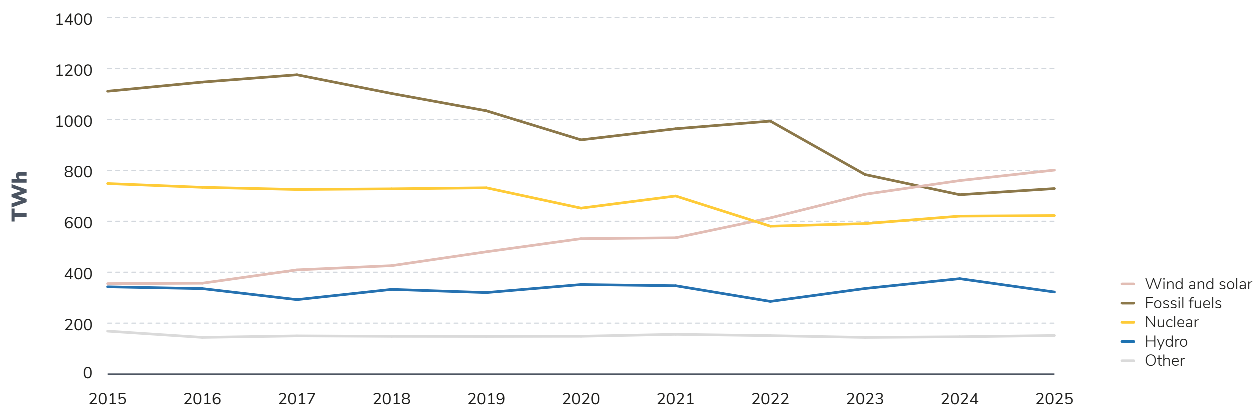
With an increase of 19% (+51 TWh, including only +8 TWh in France) in 2025 compared with 2024, **solar output showed the strongest growth, at a similar rate to the previous year.** Wind generation fell slightly (–2%, –10 TWh) due to less favourable weather conditions than in 2024.

**Hydropower production fell significantly in 2025 (–14%, –52 TWh),** after an exceptional year in 2024, returning to a level close to the average of the previous ten years. Against this backdrop, fossil-fired generation rose slightly (+3%, +24 TWh), mainly

**Figure 7.8 – Electricity generation in Europe (scope: EU-27)**

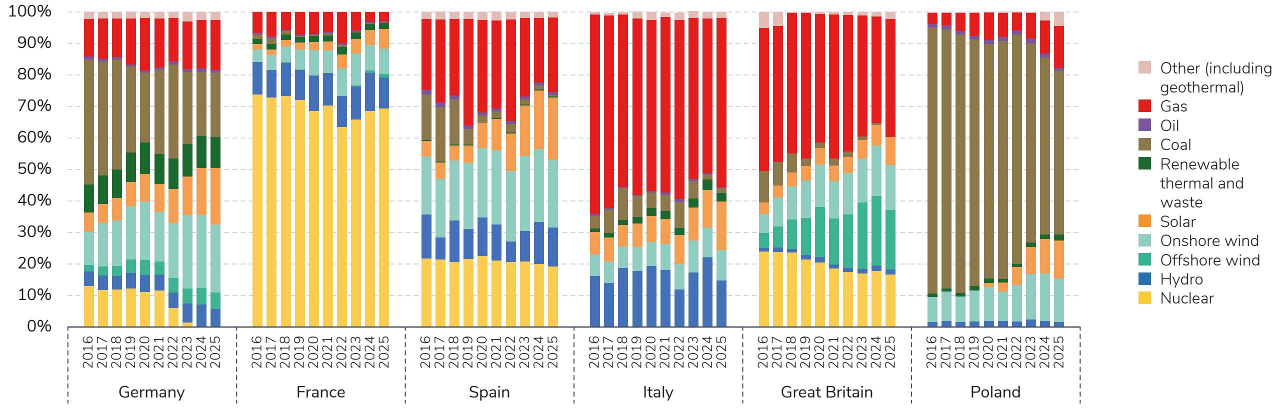



**Data source:** ENTSO-E, Energy-Charts, RTE, REE, NedNL, CBS – **Graph:** RTE




**Data sources:** ENTSO-E, Energy-Charts, RTE, REE, NedNL, CBS – **Calculations:** RTE

**Figure 7.9 – Electricity mix in Europe's six largest consumer countries between 2016 and 2025**




**Data source:** ENTSO-E, Energy-Charts, RTE, REE, National Grid

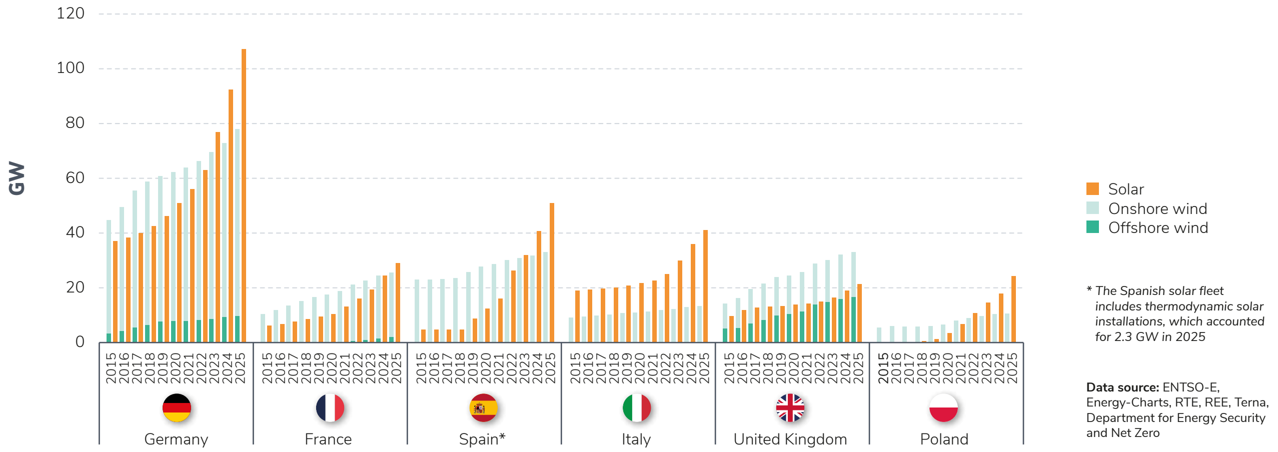
driven by gas, while coal-fired generation continued to decline (–10 TWh or –4%) and now represents less than 10% of the generation mix.

Despite this, **combined solar and wind output exceeded fossil generation for the second year running.** Nuclear and renewable thermal generation volumes remained stable.

## Solar

**The increase in solar output (+51 TWh or +19%) is similar to the previous year (+46 TWh or +20%).** The volume generated across the European Union almost tripled in 2025 compared to its 2019 level. Solar generation rose in all countries, driven largely by the increase in the size of the fleet[10]. Better sunshine

**Figure 7.10 – Growth in installed wind and solar generation capacity in a selection of European countries (values on 31 December for each year, except the UK at the end of Q3 2025)**




** The Spanish solar fleet includes thermodynamic solar installations, which accounted for 2.3 GW in 2025*

**Data source:** ENTSO-E, Energy-Charts, RTE, REE, Terna, Department for Energy Security and Net Zero

10. SolarPowerEurope estimates the solar photovoltaic capacity installed in the EU at 65.1 GW, an increase of 19%. Source: SolarPower Europe (2025): EU Solar Market Outlook 2025–2030

than in 2024 also contributed, though to a lesser extent. As a result, **solar generation exceeded hydropower output in the EU for the first time.**

The pace of solar capacity growth remained high in the European Union, having reached record levels in several countries in 2024. Notably, Germany installed 14.8 GW in 2025, the second highest growth rate in recent years behind the 15.5 GW installed in 2024. Similarly, Italy installed 5.1 GW in 2025, compared with 6 GW in 2024. This slight decline is due to a drop in residential installations. Spain was one of the few countries to have installed more solar capacity in 2025 than in 2024: 10.4 GW compared with 8.7 GW. It was also the first European country where the share of solar-generated electricity in the production mix reached 20%. Germany was close behind, with an 18% share of the mix.

## Wind

**Wind generation fell slightly (–10 TWh, –2%) as a result of unfavourable wind conditions,** despite the continued increase in the size of the European wind-powered generating fleet. This slight fall did not interrupt the momentum of wind power, since **generation in 2025 was identical to the 2023 figure and remains the second highest behind 2024; it was almost twice as high as in 2015.**

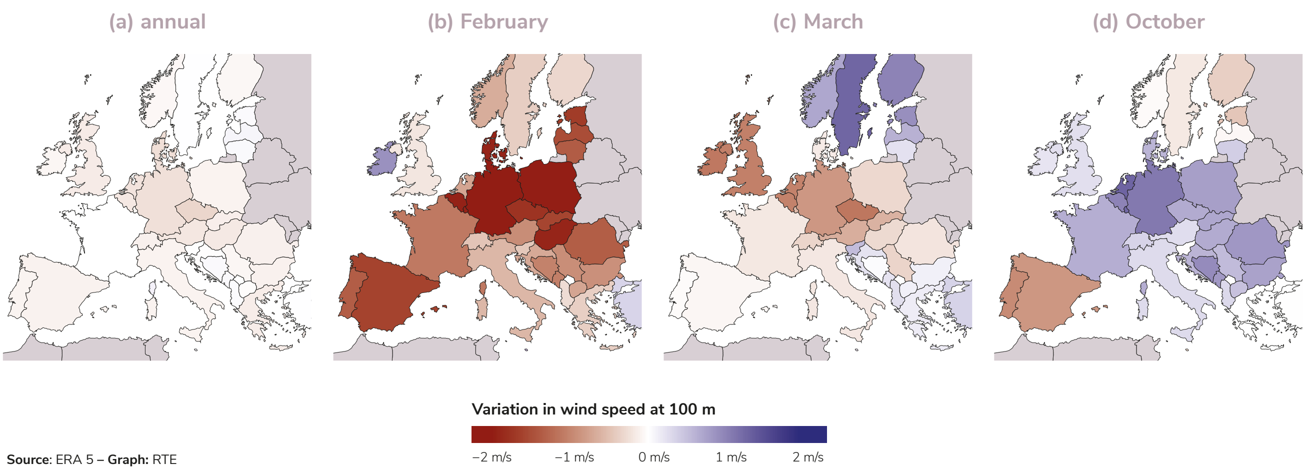
While generation from offshore wind farms was almost identical to 2024, it was onshore wind farms that saw their output fall, particularly at the beginning of the year. The months of January to April saw a sharp fall (particularly clear in February), which was partly offset by higher output in May, June and especially October.

Despite the slight drop in wind generation and the slight rise in gas-fired generation, **wind output (onshore and offshore, around 480 TWh) remained higher than gas-fired generation (around 450 TWh) for the second year in a row.**

The installation of new onshore and offshore wind capacity continued at a relatively steady pace in most European countries, but more slowly than the growth of solar power.

A detailed analysis of wind profiles across the different countries reveals contrasting trends. On an annual scale, all the European countries except the Scandinavian countries experienced less favourable wind conditions in 2025 than the average for the period between 2015 and 2024. The Nordic

**Figure 7.11 – Variations in average wind speed in 2025 compared with 2024**



countries were not affected by the drop in wind output at the beginning of the year, benefiting from very favourable winds in March, while the fall in January and February was limited. Meanwhile, Ireland was not affected by the February lull like the rest of Europe. Even if wind patterns are correlated between neighbouring countries, the diversity of situations illustrates the usefulness of electricity trading, which makes it possible to partially compensate for different wind profiles.

**Overall, the share of wind and solar power in the European energy mix rose by two percentage points, from 29% to 31%.**

## Hydropower

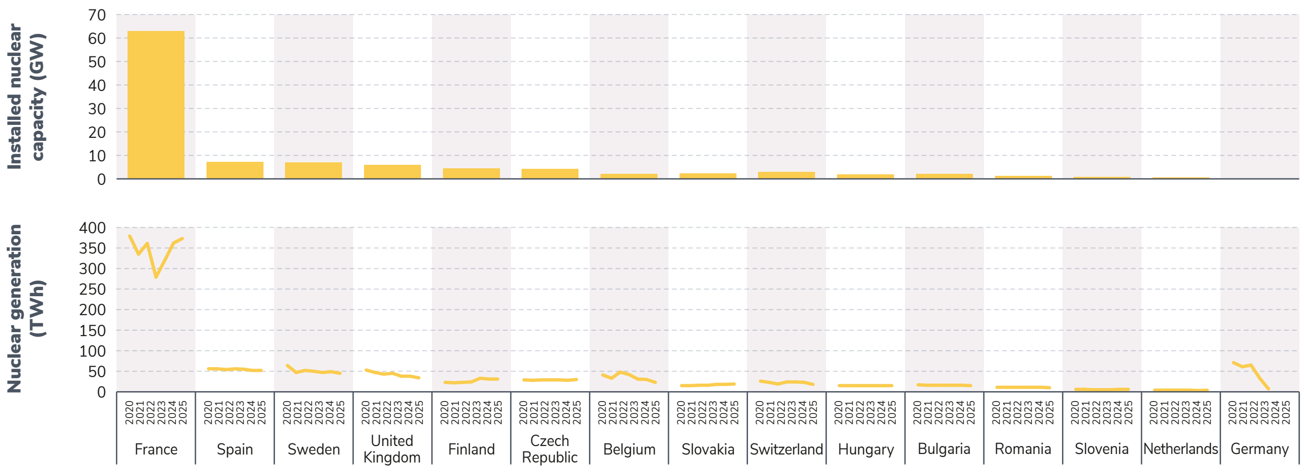
Hydropower generation reached an exceptional level in 2024, achieving its highest value in the last decade, thanks to very high rainfall. **As a result of a less rainy year, hydropower generation fell sharply in 2025** (–52 TWh, –14%), though it remained at a level close to the 2014–2023 average. The drop in output was particularly marked in the countries surrounding the Alps (around –20%), while the countries on the Iberian peninsula saw their production stagnate or fall slightly (+1% for Portugal, –4% for Spain). Northern European countries such as Norway and Sweden even saw a slight increase (+4% in Norway and +6% in Sweden).

## Nuclear

**Nuclear generation in Europe remained stable overall in 2025 (+2 TWh, +0.3%). While French generation increased compared with 2024 (+11 TWh), output across the other countries fell by almost as much,** particularly in Belgium and Sweden. Outside the European Union, nuclear generation also fell in Switzerland and Great Britain. Only the Czech Republic and Slovakia recorded significant increases in their output in 2025.

In Belgium, three reactors were shut down in 2025 (Doel-1 at the beginning of the year, Tihange-1 and Doel-2 in the autumn) as part of the process of phasing out nuclear power adopted in 2003, following two other reactor shutdowns in 2022. As a result, nuclear generation fell by 7 TWh (–24%) compared with 2024, and nuclear's share of the generation mix reached 33% in 2025, compared with 51% in 2021. The two reactors remaining in operation (commissioned in 1985), Doel-4 and Tihange-3, were originally due to close in September 2025, but their

**Figure 7.12 – Installed nuclear capacity on 31 December 2025 and annual nuclear generation in Europe**




**Data source:** Eurostat, ENTSO-E, Energy-Charts, RTE, REE, National Grid – **Calculations:** RTE lifespan was extended by ten years in 2022: now they are scheduled to close in 2035[11]. In addition, a parliamentary vote in March 2025 repealed the 2003 law, opening up the possibility of reopening existing reactors or building new plants.

In Sweden, the drop in nuclear generation (–4 TWh, –8%) was cyclical. It was due to the country's largest reactor (Oskarshamn 3, with a capacity of 1.45 GW) being shut down from April to October: the initial outage for maintenance and refuelling was extended due to the discovery of a crack in a difficult-to-access pipe in the primary circuit.

In Finland, output from the Olkiluoto 3 EPR, commissioned at the end of 2022, was stable in 2025 compared with previous years, at 10.1 TWh, as was output from the country's entire nuclear fleet. The commissioning of this reactor increased the nuclear share of Finland's electricity generation mix from an average of 35% over the period 2012–2021 to 40% since then.

The Czech Republic is one of the few countries where nuclear generation increased in 2025 (+2.2 TWh or +8%), reaching its highest level in the last thirteen years. This increase is mainly due to the two reactors at the Temelin power station, which were only shut down once in 2025 due to investment to extend the fuel cycles[12]. The nuclear share of the Czech electricity mix reached an all-time high of 42% in 2025.

In Slovakia, reactor 3 at the Mochovce power station was commissioned in 2023. Construction of the reactor began in 1987 but was interrupted by the collapse of the USSR and then resumed in 2008. Its output increased in 2024 and 2025 (3.6 TWh), helping Slovakia's nuclear generation to increase by 1.1 TWh in 2025 (6%). Construction of reactor 4 also began in 1987, and then suffered the same setbacks. It could be brought into service in 2026, following tests conducted in 2025.

Outside the European Union, Swiss nuclear generation fell by 4.6 TWh between 2024 and 2025 (–20%) due to the extended shutdown of a reactor for an essential upgrade to the water supply system[13]. In Great Britain, generation fell by 4.2 TWh (–11%) between 2024 and 2025, mainly due to low fleet availability[14]. Total generation reached 34.1 TWh, the lowest level since 2012, partly because of the closure of 11 end-of-life reactors between 2000 and 2022. Five reactors are still in service, with a total installed capacity of 6.5 GW. Finally, Ukraine has around 13 GW of nuclear capacity, with annual output of between 50 and 100 TWh, putting the country ahead of Spain in terms of production. Nuclear output accounts for around 50% of the country's electricity generation mix, although no recent figures have been published since the large-scale invasion by Russia.

## Fossil fuels (gas, oil, coal)

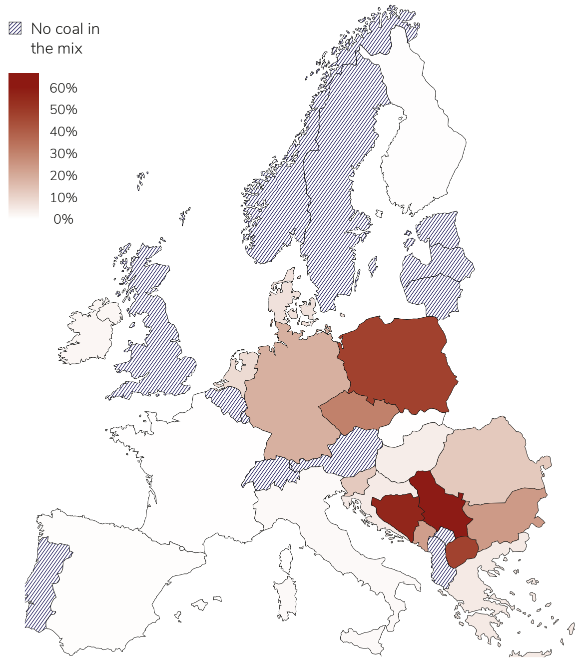
**The sharp drop in hydropower generation led to a slight cyclical increase in fossil-fired generation in the European Union in 2025 (+24 TWh, +3%), following two years of sharp decline** (–21% in 2023 and –10% in 2024). The increase was driven by gas-fired generation (+35 TWh, +9%), while coal-fired generation continued to fall (–10 TWh, –4%).

**As a result, the increase in fossil generation in 2025 did not undermine Europe's pathway to phasing out coal,** despite some delays due to the geopolitical context. In Italy, for example, the last two coal-fired power stations in operation, representing capacity of almost 4 GW, were due to close in 2025, but this closure was postponed indefinitely in September[15] due to uncertainty over the security of the gas supply in Europe. In Spain, out of the last three coal-fired power stations still in operation, Aboño (916 MW) is being converted to gas[16] and the other two produced very little in 2025 (<400 GWh). In Ireland, the last coal-fired power station, Moneypoint, was mothballed in 2025 and will remain so until 2029.

11. AFCN, *Exploitation à long terme (LTO) de Doel 4 et Tihange 3 jusqu'en 2035*, November 2025
12. Skupina CEZ, *Temelín překonal historický výrobní rekord*, December 2025
13. ENSI, *Maîtrise de ruptures dans le système d'alimentation en eau de la centrale nucléaire de Gösgen*, September 2025
14. Department for Energy Security & Net Zero, *Energy Trends*, September 2025
15. Reuters, *Gas storage levels in Italy and Europe are good, Italian minister says*, September 2025

Other countries have completed their phase-out of coal in recent years: Belgium in 2016, Austria and Sweden in 2020, Portugal in 2021 and Great Britain in 2024. **As a result, coal accounts for a negligible, if any, share of the electricity production mix in most European countries.** Of the remaining countries, Poland, Germany and the Czech Republic account for over 80% of coal-fired generation in the European Union. Even in these countries, however, the share of coal continues to fall sharply year on year. In Germany, for example, coal-fired generation has fallen by 60% in 10 years, and its share of the mix has declined from 40% in 2016 to 20% in 2025.

**Figure 7.13 – Share of coal-fired electricity generation in the electricity mix of several European countries in 2025**

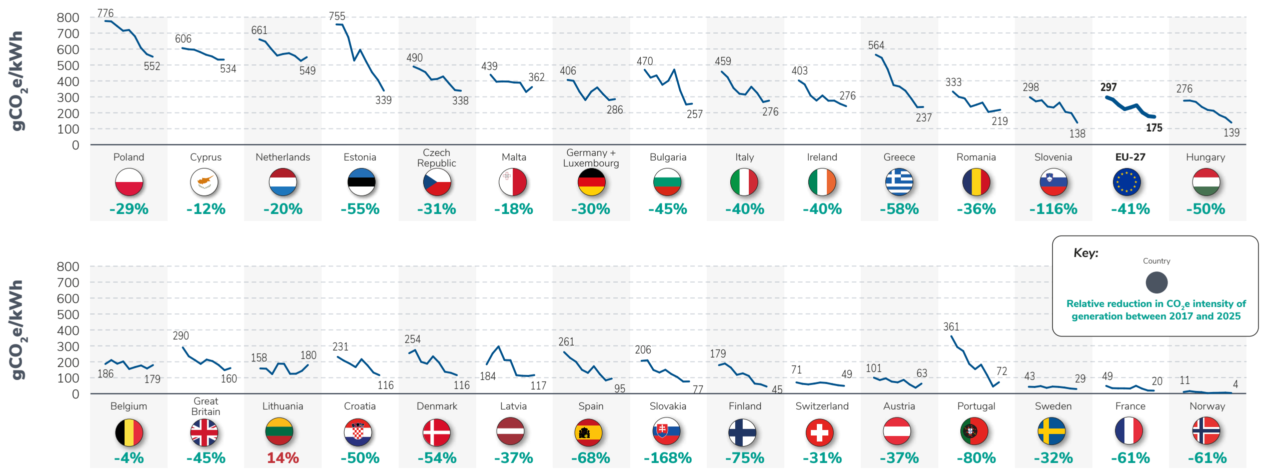



16. EDP, *EDP and Corporación Masaveu complete conversion of Aboño power plant to natural gas*, July 2025

# The carbon content of electricity generated in the European Union fell by more than 40% between 2017 and 2025

The decarbonisation of Europe's power system is continuing. Between 2017 and 2025, the average carbon intensity of the electricity produced in the 27 European Union member states fell by 41%, from 297 $gCO_2$/kWh in 2017 to 175 $gCO_2$/kWh in 2025. Over this period, the carbon content fell in all member states (but also in other European countries such as Great Britain, Norway and Switzerland), except for Lithuania[17]. French electricity generation has long been among the lowest-carbon in Europe, and is now second only to Norway. In some countries, the speed of decarbonisation is spectacular. Thanks to the massive development of renewable energy, particularly wind, and the closure of most of their coal-fired power stations, Spain and Portugal reduced the carbon intensity of their electricity generation by 68% and 80% respectively over the period. The closure of coal-fired power stations has enabled countries such as Greece, Bulgaria and Great Britain to halve the carbon intensity of their generation mix.

**Figure 7.14 – Average carbon intensity of electricity generation in the countries of the European Union, the United Kingdom, Norway and Switzerland**




*Note: the generation data used for this calculation comes from ENTSO-E's Transparency Platform. A small number of countries and energy sources have known quality problems (e.g. solar output data in the Netherlands). In these rare cases, this can lead to an overestimation of carbon intensity.*

17. This increase can be explained by the fact that the Lithuanian power system is relatively small (annual consumption is in the region of 10 TWh), and highly dependent on imports (between 2017 and 2025, imports from Sweden, Poland and Latvia covered between 25% and 60% of the country's electricity consumption, depending on the year); the carbon content of electricity generation is therefore also highly variable, depending on the volume still to be covered by domestic generation.

# Battery storage is developing strongly and changing in scale

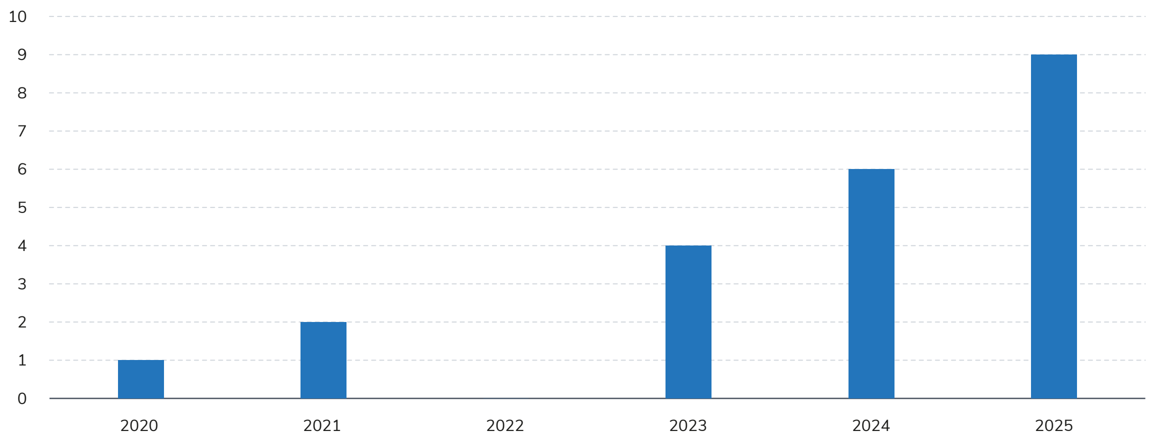
Battery storage is one of the levers that can contribute to the flexibility of the power system, in addition to others such as dispatchable generation resources, the (downward) flexibility of wind and solar installations and demand-side flexibility. In many countries, batteries already contribute to balancing supply and demand in near-real time, and increasingly to flexibility on longer time scales of up to a few hours (e.g. storing energy when solar generation is high during the day and releasing it at night). The economic space for these sources of flexibility in the years to come will depend on trends in consumption and generation.

In 2025, the total capacity of batteries deployed on the European grid was between 16 and 19 GW, plus equivalent capacity of residential storage. The United Kingdom is ahead of the other countries, with 7 GW installed on the grid, followed by Germany, Italy, France and Ireland, each with total capacity of 1 to 3 GW[18].

Batteries can be installed in homes, often coupled with a photovoltaic system, which increases the rate of self-consumption of the electricity generated. They typically have a capacity of a few kilowatts and can deliver electricity at full power for one or two hours. For example, residential storage accounts for 80% of the stationary batteries installed in Germany[19] (in terms of stored energy), the country where this type of battery is developing fastest due to the level and structure of tariffs for households.

Industrial projects, generally larger than one megawatt, contribute to the various markets (system services, balancing mechanism, wholesale market); they can also be installed by the operators of large wind or solar farms to store surplus electricity and re-inject it at other times. These projects are growing fast, in both size and number: over the last fifteen years, they have moved from the demonstrator stage, with a capacity of around 1 MW, to industrial projects of several hundred MW, with a storage time of one to two hours. In particular, the number of battery farms larger than 100 MW commissioned annually has risen sharply in recent years, from just one site in 2020 to nine in 2025.

**Figure 7.15 – Number of storage facilities larger than 100 MW commissioned per year in Europe**




**Data source:** European Energy Storage Inventory

18. Sources: European Energy Storage Inventory, Aurora Energy Research, Solar Power Europe, Clean Horizon Consulting.
19. Chair for Electrochemical Energy Conversion and Energy Storage Systems, *Battery-Charts*, 2025

The capacity, in terms of storage time, of projects under construction or announced is also trending upwards: the largest can represent the equivalent of the energy generated by a nuclear reactor for two to four hours.

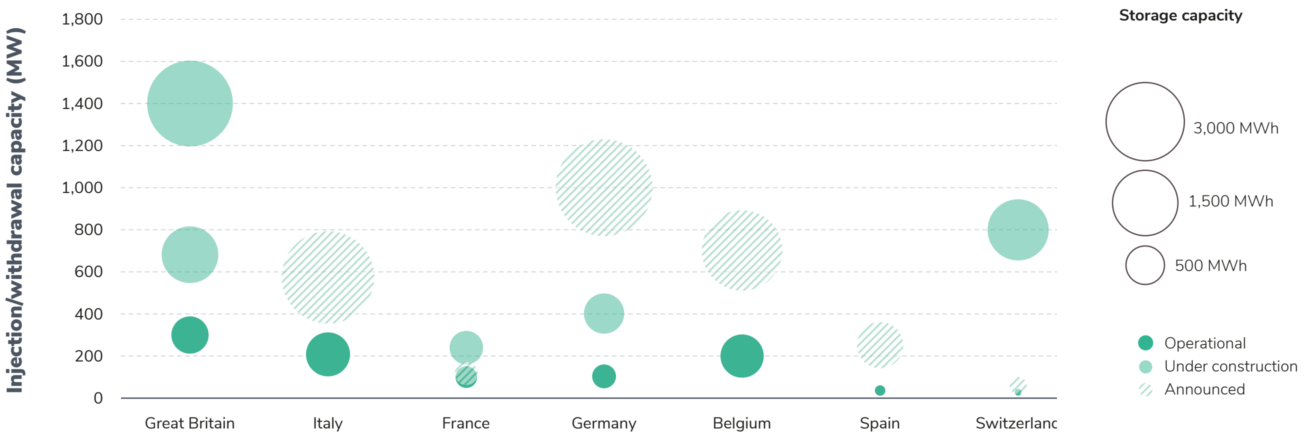
Some battery storage projects announced in 2025 have even reached the gigawatt mark, with storage capacity for several hours:

- The 1.45 GW/3.1 GWh Thorpe Marsh project (approximately two hours of storage at full power) in Yorkshire, England, developed by Fidra Energy Ltd; construction began at the end of 2025 and the site should be operational by the end of 2027.
- The GigaBattery Jänschwalde 1000 1 GW/4 GWh project in eastern Germany (four hours of storage at full power), developed by LEAG Clean Power GmbH, was announced in 2025 and should be operational in 2027–2028.

Several countries have set up support mechanisms to encourage projects with longer storage times (over four hours), equivalent to what PSH can offer, and thus facilitate renewable energy integration:

- In Italy, the *Mercato a termine degli stoccaggi* (MACSE) tender, announced by Terna in September 2025, aimed to select battery storage projects for commissioning in 2028. This call for tenders operates like a capacity market, with successful bidders receiving compensation in exchange for the obligation to offer their storage capacity on a dedicated platform. A total of 14 storage projects were selected, offering 1.5 GW and 10 GWh of storage in total. The projects vary greatly in size, from 34 to 574 MW, but all offer between six and eight and a half hours of storage[20]. These projects will receive between €12,000 and €16,000/MWh per year for 15 years.
- In the UK, following a government decision in 2024, the energy regulator (Ofgem) issued public tenders for Long Duration Energy Storage (LDES) with capacity for eight hours. Selected projects will benefit from a cap and floor CfD-type scheme. Ofgem found that 77 projects were eligible in 2025, representing a total of 29 GW, including 20 GW of Li-ion batteries for delivery between 2030 and 2033. The final selection should take place in summer 2026[21].
- Spain announced it was allocating €827 million to 133 storage projects in 2025. These projects should be operational by 2029, totalling 2.3 GW and 10 GWh of storage[22].

**Figure 7.16 – Main battery storage projects in France and neighbouring countries**




20. Terna, *Meccanismo di approvvigionamento di capacità di stoccaggio elettrico, rendiconto degli esiti*, asta 2028, 2025
21. Ofgem, *Super battery projects that maximise renewable-generated power enter next phase of Ofgem's green power storage scheme*, 2025
22. Instituto para la Diversificación y Ahorro de la Energía, *Resolución definitiva*, Table 1 p227, December 2025

# European electricity trading continued to play its role to the full in optimising the electricity generation mix on a continental scale in 2025

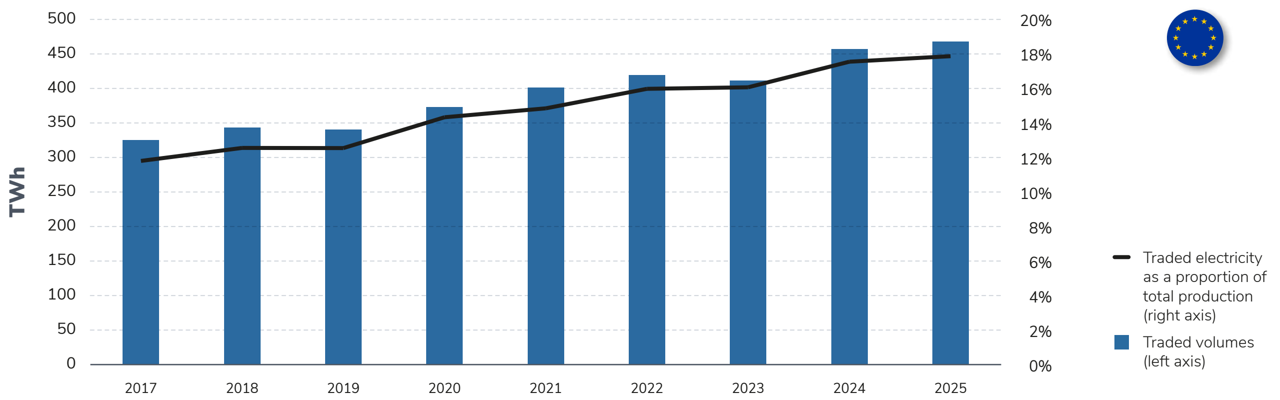
In 2025, **468 TWh were traded between European Union countries, amounting to around 18% of total generation and a similar level to 2024.** These volumes have tended to increase over the last twenty years as a result of growth in interconnection capacity on one hand and success in developing the integration of Europe's markets on the other. This integration facilitates electricity trading so that low-cost, low-carbon resources (renewable, nuclear) can be given priority throughout the interconnected system, including in neighbouring countries, before more expensive fossil-fired resources. This minimises the cost of electricity generation across the interconnected zone.

Trade between EU countries and their non-EU neighbours is much lower in volume terms. Over the last ten years, it has not exceeded 20 TWh in either direction. In 2025, the European Union was a net exporter of electricity to neighbouring countries to the tune of 18 TWh, slightly more than in 2024 (7 TWh), in contrast to previous years since 2017, when it had a slight trade deficit. This development is mainly due to three trends:

- The balance of the European Union's trade with Ukraine was negative before 2023, with imports of 3 TWh on average; it then turned slightly positive, at 0.5 to 4 TWh depending on the year.
- The balance of trade with Great Britain has almost always been on the export side over the period from 2018 to 2025, with the exception of 2022; its value increased from 19 TWh in 2023 to 28 TWh in 2025.
- The deficit with Switzerland was almost wiped out in 2025, moving from 14 TWh of imports in 2024 to 0.3 TWh of imports in 2025.

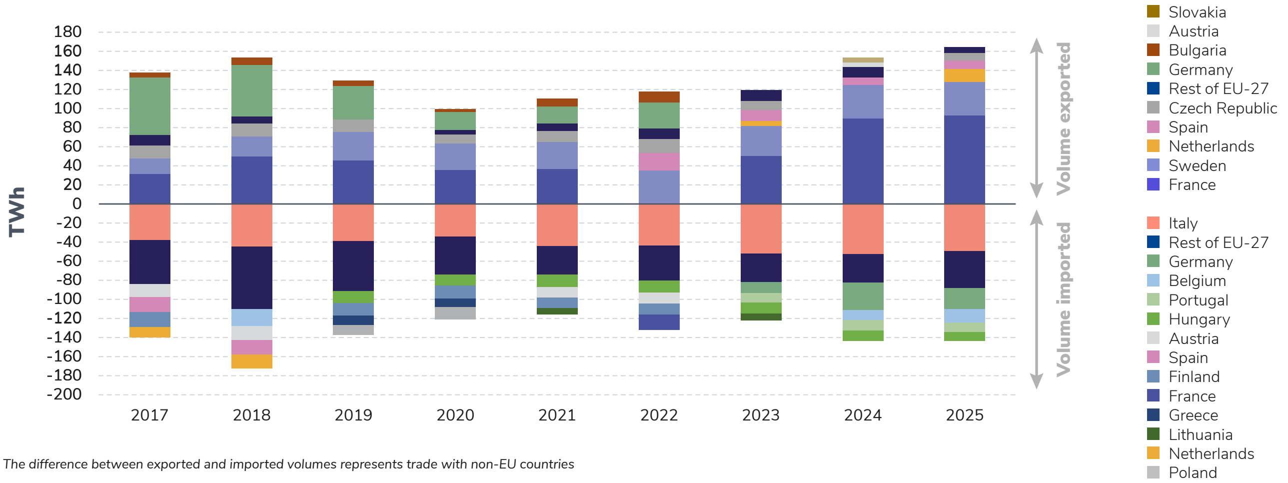
**Country by country, 2025 did not reverse any trends in trade balances compared with the previous year.** As in 2024, France had the highest export balance in Europe, setting a new record (92.3 TWh in 2025 compared with 89.0 TWh in 2024 – see the Trading chapter). French net exports accounted for more than half (56%) of all exports from EU countries.

**Figure 7.17 – Volumes of electricity traded within the European Union (left axis) and traded electricity as a proportion of total production (right axis)**




**Data source:** ENTSO-E, RTE, Energy-Charts, REE, CBS, NedNL – **Calculations:** RTE

**Figure 7.18 – Breakdown of volumes exported and imported by European Union countries**




*The difference between exported and imported volumes represents trade with non-EU countries*

**Data source:** ENTSO-E

Also as in 2024, Sweden's trade balance was in surplus, second only to France. Sweden has been a net exporter since 2017, but its surplus has more than doubled in absolute terms over that period (35 TWh in 2025 compared with 16 TWh in 2017), driven by an increase in wind generation in the same proportions (from 17 TWh in 2017 to 38 TWh in 2025).

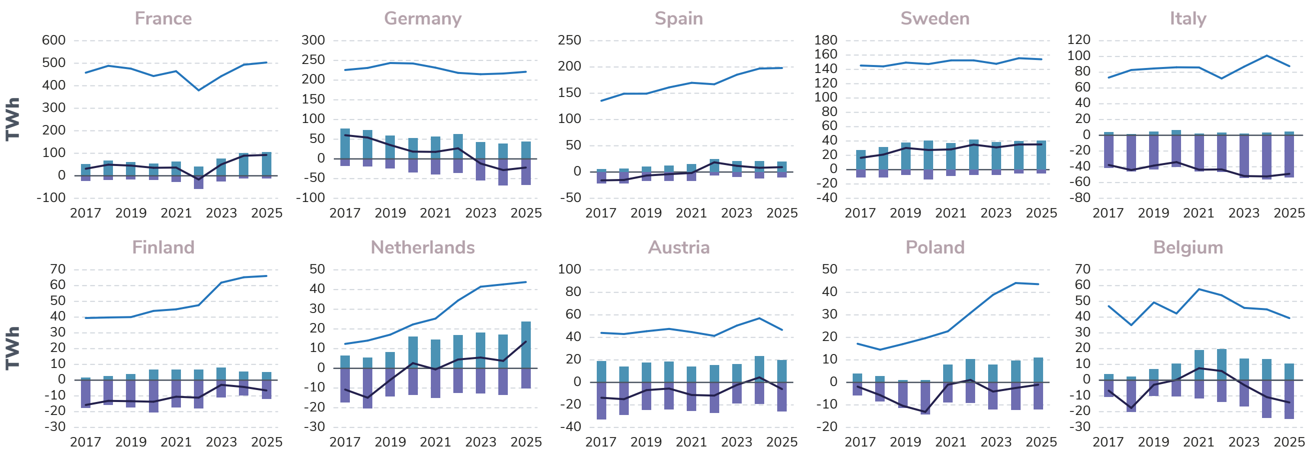
Italy was still the country with the highest net import balance among EU countries in 2025, accounting for a third of total imports. Looking at the wider scope, i.e. tracing trade flows beyond directly neighbouring countries[23], France was the leading exporter to Italy in both 2025 and 2024, covering two-thirds of Italian imports (33 TWh, 66%); the other main countries where Italian imports originated, well behind France, were Switzerland (3.4 TWh, 7%) and Sweden (2.8 TWh, 5%).

**For most countries, trading trends are influenced by changes in the generation mix: in general, the volume exported increases when low-carbon generation is plentiful** (solar, wind, hydropower and nuclear). Decarbonising the mix helps to make electricity generation more competitive, which has a positive impact on export volumes and thus on the balance of trade. This effect can be seen in several countries: France first of all (see detailed analysis in the *Trading* chapter), but also the Netherlands, Austria, Belgium and Spain.

The Dutch trade balance has been rising almost continuously since it became a net exporter in 2020. It was also an exporter every month of the year for the first time in 2025, having been a net importer every month in 2018. Though its annual balance of trade with Norway remains in deficit, the balance with Germany and Belgium has changed the most, with both countries exporting on a monthly basis for the first time in 2025. In total, around 60% of Dutch imports and exports in 2025 consisted of flows passing through the country, with the remaining 40% being exports of power generated in the Netherlands or imports for domestic consumption. As a result of the way the European electricity market works, the Netherlands imports Norwegian hydroelectricity continuously, except from June to September, when it exports its solar output in the middle of the day. It also exports Norwegian hydroelectricity and its own solar power to Belgium and Germany.

23. In particular, some of the flows that France exports to Switzerland are re-exported to Italy (see the section on tracing trade at European level in the Trading chapter).

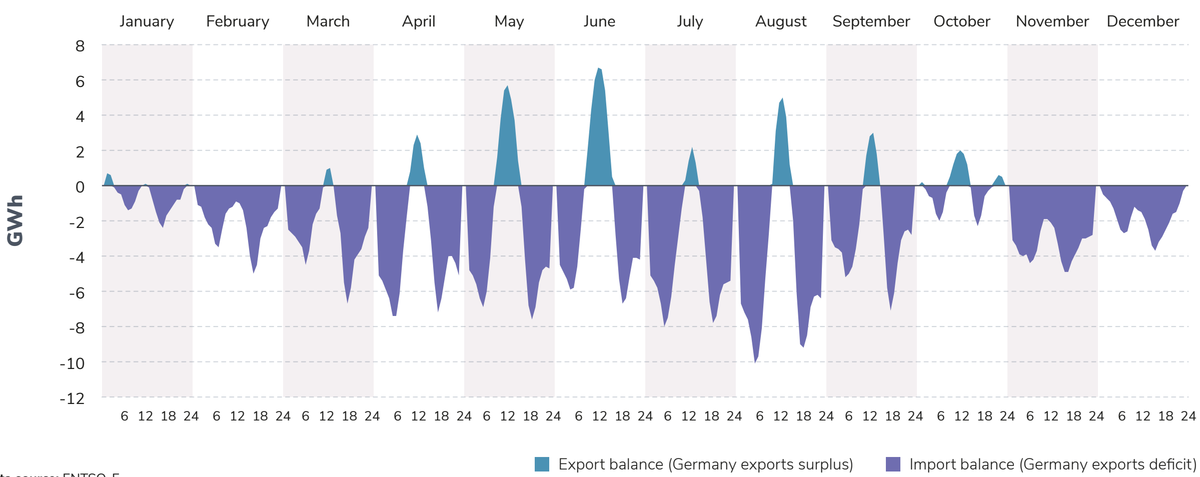
**Figure 7.19 – Annual trade and low-carbon generation for a selection of European countries between 2017 and 2025**




**Data sources:** ENTSO-E, RTE, Energy-Charts, REE, CBS, NedNL

Germany's trade balance was negative in 2025, as in the two previous years, whereas it was a net exporter until 2022 and even Europe's leading exporter in 2018. The shifts in Germany's trade balance are closely linked to wind generation, in terms of both daily and monthly variability and annual trends, and to the phase-out of nuclear power, which has had a marked effect on the overall direction of trade in recent years. Germany closed its last three nuclear reactors in 2023; nuclear accounted for around 24% of its electricity mix in 2010 and 12% in 2019. Since 2023, the abundance of low-carbon, low-cost generation in neighbouring countries (French nuclear, Nordic wind and hydroelectricity, Dutch solar) has enabled Germany to limit the use of its more expensive and carbon-intensive fossil-fired fleet, relying instead on imports. On a smaller scale, trade between Germany and neighbouring countries

**Figure 7.20 – Average hourly profile of Germany's trade balance in 2025**




**Data source:** ENTSO-E

is influenced by solar and wind generation. In 2025, Germany was generally a net exporter during hours of high solar generation, in the middle of the day in spring and summer, as well as on certain nights in January and October, when wind generation was very high. Conversely, the country imported the most during the mornings and evenings in the summer months. Midday exports in July were lower than in the other months between April and September due to particularly low solar generation for the period: though this was 30% higher on average in 2025 for each month compared to the same months in 2024, generation was 8% lower in July 2025 than in July 2024 due to unfavourable sunshine conditions[24].

24. Source: ECMWF ERA 5

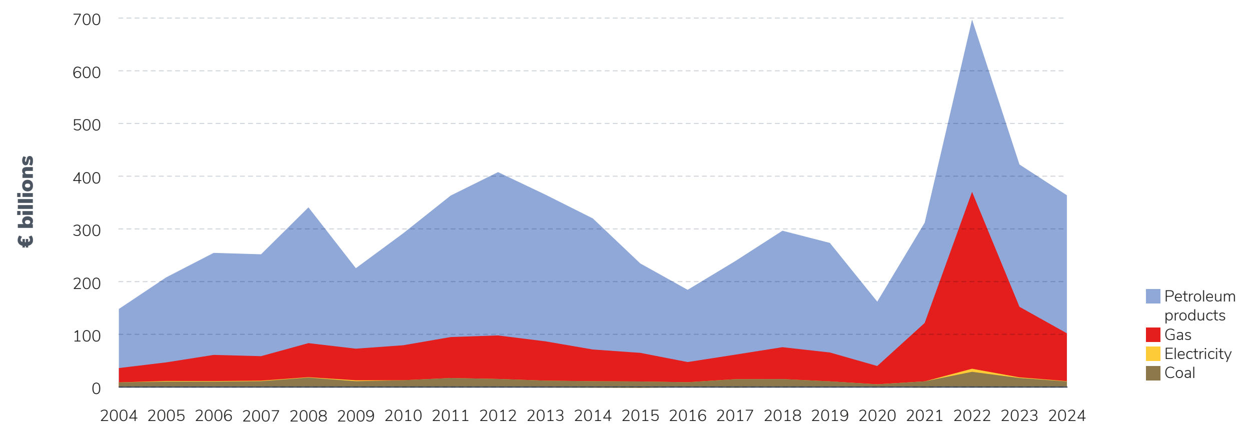
# The European Union relies heavily on fossil fuel imports for its energy supply

**As the European Union produces very little oil and gas, it is heavily dependent on imports for its energy supplies.** In 2024, the European Union's imports of oil products, gas, coal and electricity amounted to €360 billion[25], or around 15% of the EU's total imports of goods. Imports reached almost €700 billion in 2022, at the height of the triple energy crisis (high fuel prices, low availability of French nuclear generation, decline in hydropower generation) affecting electricity prices in Europe. Although imports followed a downward trend in 2024 compared with the previous two years, they remained higher than at almost any time between 2004 and 2021, a sign of Europe's marked dependence on its global partners.

Europe was dependent on fossil fuels for 27% of its electricity generation in 2024. This figure has been falling for several years (41% in 2015) thanks to the gradual decarbonisation of Europe's energy mix. As fossil fuels become electrified, this can provide leverage for decarbonising the economy as a whole, reducing both greenhouse gases and Europe's energy bill.

**In an increasingly uncertain geopolitical context, the electrification of energy uses also represents a strategic opportunity to reduce dependence on non-European countries for critical supplies such as energy,** where the repercussions of shocks can be massive, as the effects of Russia's invasion of Ukraine on gas prices have shown. Non-European countries currently comprise the majority of the European Union's main suppliers, which represents a risk factor in the current context. In 2024, the main gas exporters to the European Union by value were Norway (27% of imported gas), Algeria (18%), the United States (17%) and Russia (17%); the main oil exporters were the United States (16% of imported oil products by value), Norway (13%) and Kazakhstan (12%).

**Figure 7.21 – The European Union's energy bill (EU-27)**




**Data source:** Eurostat – BNetzA/BAFA – **Calculations:** RTE

25. RTE estimate based on data from Eurostat and, for Germany, the energy regulator (BNetzA) and the German Federal Office for Economic Affairs and Export Control (BAFA).

FOCUS

## Information on the data used in this chapter

The European data used in this chapter is all publicly accessible. Among the multitude of sources available, RTE strives to select the most reliable and up-to-date at the time of writing. This data is subject to subsequent corrections and updates and may therefore differ from the data available at the time of publication. The sources consulted were: ENTSO-E, Eurostat, Energy-Charts, Red Electrica de España (REE), Terna, National Grid, Nationaal Energie Dashboard (NedNL), the Dutch national statistical institutes (Centraal Bureau voor de Statistiek (CBS), Destatis, Tilastokeskus, Statistikbanken, INE, Istat), the European Centre for Medium-Range Weather Forecasts (ECMWF ERA 5), the German energy regulator (BNetzA) and the German Federal Office for Economic Affairs and Export Control (BAFA).

# Appendices

**2025 ELECTRICITY REVIEW**

## Glossary

| Keyword | Definition |
|---|---|
| Adjusted consumption | *Electricity consumption adjusted for weather and calendar effects:* consumption that would have been recorded at the reference temperatures, and excluding consumption on 29 February for leap years. |
| ASN | In France, the Autorité de sûreté nucléaire (nuclear safety authority) is the body responsible for monitoring nuclear safety, radiation protection (nuclear power workers, the environment, local populations) and public information "to protect workers, patients, the public and the environment from the risks associated with nuclear activities" on behalf of the government. |
| Balancing mechanism | Mechanism enabling RTE to call on power reserves available at any time to ensure a permanent balance between electricity supply and demand. RTE can ask the various players who have submitted bids to modulate their generation or consumption upwards or downwards. |
| Biofuel | Alternative fuels obtained from biomass (raw material of plant, animal or waste origin). Biofuels are generally incorporated into fossil fuels. |
| CBS | *Centraal Bureau voor de Statistiek:* the Dutch national statistics institute. |
| $CO_2e$ | *Carbon dioxide equivalent:* index used for comparative emissions measurements between greenhouse gases according to their global warming potential. The volume of gas emitted is reduced to the equivalent quantity of carbon dioxide required to achieve the same warming potential. |
| Core region | Region in which trading capacity is calculated and markets are coupled, including France, Germany, Belgium, the Netherlands, Austria, Slovenia, Poland, the Czech Republic, Slovakia, Croatia, Hungary and Romania. |
| Coverage rate | The coverage rate for consumption is the ratio between the output of a generation source and the energy consumed. In the Electricity Review, the monthly and annual coverage rates correspond to an average of the coverage rates calculated at 30-minute intervals. |
| CSPE | *Contribution au service public de l'électricité:* tax deducted from electricity suppliers' electricity bills. |
| Demand response | Scheme in which a consumer reduces or shifts all or part of its electricity consumption in response to a signal. |
| Demand-side flexibility | Intentional change in consumption in response to a given signal. |
| Dispatchable generation resource | A generating facility whose activation and power variation can be controlled (thermal or nuclear power stations, hydropower with storage, etc.). |
| Energy-Charts | Platform publishing data relating to the German electricity sector managed by the Fraunhofer Institute for Solar Energy Systems ISE. |
| ENTSO-E | European Network of Transmission System Operators (TSOs), bringing together 39 operators from 35 countries. |

| Keyword | Definition |
|---|---|
| EPEX SPOT | One of the electricity exchange operators designated by regulators. These operators organise market coupling and carry out transactions on the day-ahead and intraday markets. By decision of the CRE, the approved operators for France are EPEX SPOT and Nord Pool. |
| EPR | The European Pressurised Reactor or EPR is a nuclear reactor belonging to the third generation of pressurised water reactors. |
| Future price | Price negotiated in advance with a delivery date that may be a long way off, for a period ranging from a week to a year. |
| Fossil-fired | Electricity generation in thermal power stations fuelled by fossil fuels: gas, coal or oil. |
| Grand Carénage ("major refit") | Investment programme to upgrade the existing nuclear fleet approved by EDF's Board of Directors on 22 January 2015. As well as renovating and extending the lifespan of the reactors, the aim is to increase their level of safety and incorporate the improvements designed following the Fukushima accident in 2011. |
| Gross (or unadjusted) consumption | Electricity consumption in France (including Corsica), including network losses but excluding PSH pumping consumption. |
| Hydraulic stock | The hydraulic stock in France represents the weekly aggregated level of water available in reservoirs for storage hydropower plants. The head energy is the energy that can be generated at the (only) power station directly connected to the reservoir, depending on how full it is. The data published relates solely to the stock of head energy and is expressed in MWh. |
| Intraday prices | Prices for electricity transactions for same-day delivery. |
| LNG | Liquefied Natural Gas |
| Load factor | The load factor is the ratio between the output of a generation source and its installed capacity. In the *Electricity Review* and the *Analyses and data*portal, the monthly and annual load factors correspond to an average of the load factors calculated at 30-minute intervals. |
| Low-carbon | Low-carbon electricity is electricity generated from non-fossil primary energy sources (nuclear, onshore and offshore wind, solar photovoltaic, etc.). For the difference between low-carbon generation and consumption, see the summary table in the chapter on *Emissions (Summary of the concepts involved in calculating electricity-related greenhouse gas emissions)*. |
| Low-carbon rate | Proportion of the total volume of electricity generated from low-carbon sources (see "Low-carbon"). |
| NEBEF | Demand reduction block exchange notification (*Notification d'Échange de Bloc d'Effacement*) |
| Non-dispatchable generation resource | A generation resource whose output at any given point in time depends mainly on external factors that are difficult to predict. |
| Normal temperatures | Averages of past temperature records, considered to be representative of the relevant decade. Based on Météo-France data, they are calculated by RTE for the whole of France using a panel of 32 weather stations spread across the country. |
| Other fossil-fired power stations | Between 2001 and 2007 inclusive, the "Other" series included electricity generation in distribution networks, generation from by-product gases and generation from "miscellaneous" fuels. Between 2008 and 2010, it included by-product gases and miscellaneous fuels, while distribution network generation was broken down into oil and gas. Since 2011, all units in the "Other" series have been broken down into the gas, oil and coal series. |
| Other hydropower plants | The power plants included in the "other" category are tidal power stations and PSH (Pumped Storage Hydropower). Tidal power stations harness the energy of the tides in coastal areas with high tidal ranges (the difference in water height between the high and low tides). They use the tidal range to generate electricity by exploiting the difference in height between two basins separated by a dam. PSH plants, which operate in cycles of pumping and turbine operation between a lower and an upper reservoir, using reversible pump-turbines, are an effective storage tool that helps to balance the power system. If the reservoirs include natural inflows, the turbine falls into the "mixed" category. Otherwise, it belongs to the "pure" category. |
| Peak consumption | Peak electricity consumption refers to the time periods when electricity demand is highest. |

| Keyword | Definition |
|---|---|
| Physical exchanges | Physical exchanges reflect the flows of electricity that actually pass through the interconnection lines directly linking countries, and may be different from trading exchanges. |
| Pondage power plants | Pondage power stations, mainly located on lakes downstream of medium-sized mountains, have a reservoir filling time of between two and 400 hours and carry out modulation on a daily or even weekly basis (daily consumption peaks, between working and non-working days, etc.). |
| PPE | Multi-year energy plan (*Programmation pluriannuelle de l'énergie*): the current PPE has been in force since 2020, and a new PPE is currently being discussed as part of the French energy and climate strategy (SFEC). |
| PSH | PSH (pumped storage hydropower) plants are hydroelectric installations that pump water from a lower reservoir at off-peak times to fill an upper reservoir (high-altitude lake). The water then drives turbines at peak times to generate electricity. |
| Red Electrica de Espana | Spanish electricity transmission system operator |
| Renewable thermal and waste | Electricity generation in thermal power stations fuelled by bioenergy (solid biomass and biogas), papermaking waste or household waste (by convention, 50% of household waste is considered renewable). |
| Reservoir power plants | Reservoir power stations, located on lakes downstream of medium and high mountains, have a reservoir filling time of over 400 hours and provide seasonal storage. |
| Residual consumption | Difference between the level of consumption and the level of non-dispatchable renewable generation at each moment. |
| Run-of-river plants | Run-of-river power stations, mainly located on plains, have a low reservoir height and a filling time of less than two hours. They therefore have little capacity for modulation through storage and depend on the flow of a watercourse for their generation. |
| Self-consumption | Consumption, by a consumer, of all or part of the electricity generated by its own generating facilities. |
| SFEC | French energy and climate strategy (*Stratégie française pour l'énergie et le climat*) |
| SNBC | French national low-carbon strategy (*Stratégie nationale bas carbone*) |
| Spot price | Electricity price fixed in the day-ahead market coupling (the day before for the next day) over 24 time units. |
| Supply–demand balance | Electricity storage possibilities are limited. For this reason, electricity supply and demand must be kept in balance at all times, a task carried out by RTE. Any difference between supply and demand leads to a change in the operating frequency of the power system, which is 50 Hz when balanced. |
| Temperature sensitivity | Variations in electricity consumption linked to temperature variations. For example, electricity consumption increases in winter when the weather is cold due to the use of electric heating. |
| Ten-yearly inspection | Regular reviews of nuclear power plants, carried out every ten years by the ASN to check that installations comply with the relevant safety standards and regulations, including ASN requirements. By the end of 2023, all 56 reactors had completed their second ten-yearly inspection, 49 their third and 17 their fourth. |
| Trading | Trading involves commercial transactions between market players located in different countries. |
| Wholesale price | This can be either the spot price or a future price (see "Spot prices"). |

# Assumed emission factors used to calculate greenhouse gas emissions from electricity generation and consumption

| | Direct emission factor ($gCO_2e/kWh$) | Life-cycle emission factor ($gCO_2e/kWh$) |
|---|---|---|
| Nuclear | 0 | 7 |
| Gas – combined cycle | 331 | 389 |
| Gas – combustion turbine | 497 | 583 |
| Gas – cogeneration | 461 | 540 |
| Gas – undetermined | 435 | 471 |
| Hydrogen – combined cycle | 0 | 35 |
| Hydrogen – combustion turbine | 0 | 34 |
| Coal | 855 | 941 |
| Lignite | 961 | 1,040 |
| Oil | 769 | 928 |
| Other fossil fuels | 855 | 941 |
| Hydro – run-of-river | 0 | 6 |
| Hydro – PSH | 0 | 6 |
| Hydro – reservoir | 0 | 6 |
| Onshore wind | 0 | 16 |
| Offshore wind | 0 | 17 |
| Solar photovoltaic | 0 | 43 |
| Wood | 0 | 66 |
| Biogas | 0 | 70 |
| Biomass | 0 | 70 |
| Renewable waste | 0 | 0 |
| Industrial waste | 988 | 0 |
| Household waste (non-renewable portion) | 988 | 0 |
| Other renewable energy | 0 | 70 |
| Batteries | 0 | 67 |
| Electric vehicles | 0 | 0 |

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**RTE**
Immeuble WINDOW - 7C Place du Dôme,
92073 PARIS LA DEFENSE CEDEX, FRANCE
www.rte-france.com