

Austria's energy prices in light of climate change, international conflicts, regulation etc.



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AGENDA

Key market drivers on the curve



Weather impact

- Wind trends and El Nino



Regulation impact

- Italian energy decree and cross border capacity



Carbon price impact

- Key risks and price expectations



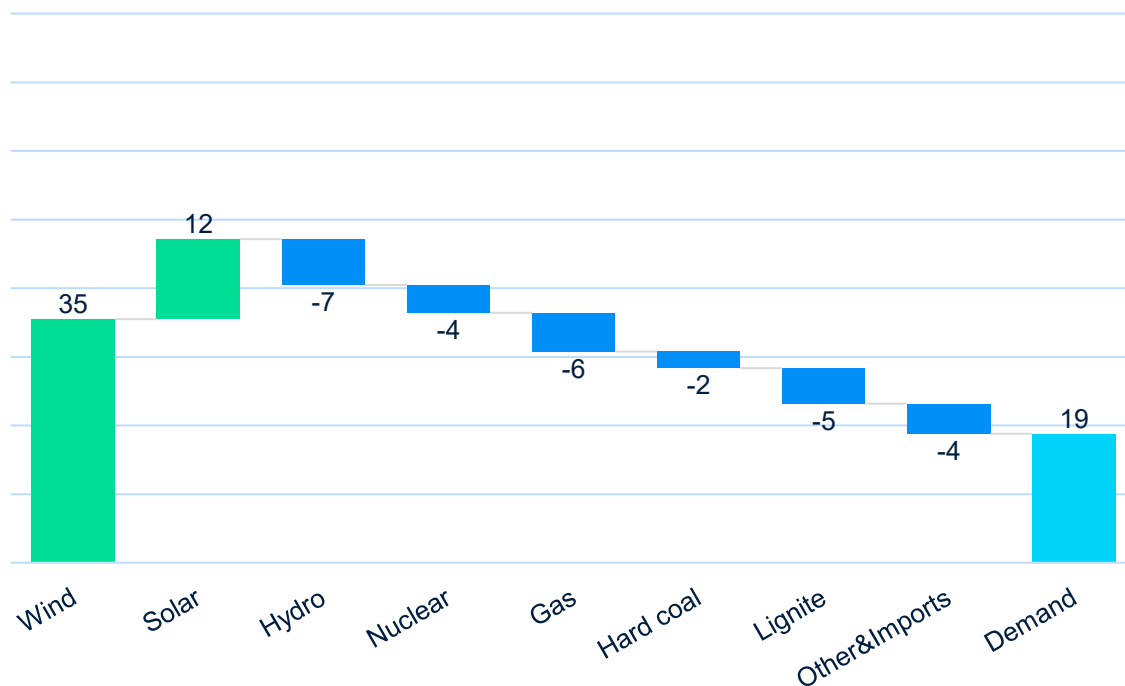
Gas price impact

- Geopolitical risks drive uneven spillovers into power prices



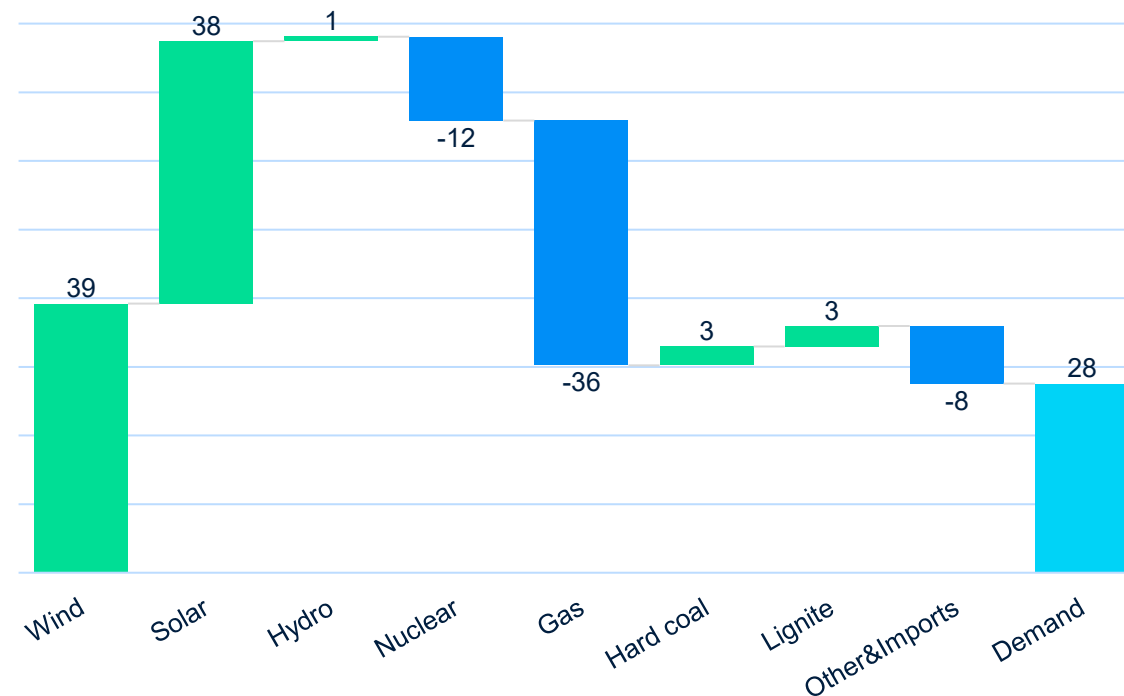
Looking back at our mid-year review: Renewables reshape the European power supply-demand balance and increasingly limit gas exposure

2026 v 2025: History (Jan-Apr), TWh

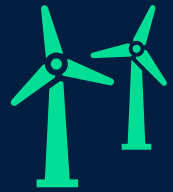


- **Wind output remains below normal but has recovered sharply from the very weak start of last year**, with the year-on-year increase more than offsetting demand growth
- **Power demand is up around 1.5–2% y/y**, partly driven by colder weather in Q1 compared with last year
- **Fossil fuel spreads have reversed materially**: gas was firmly in the money until late February, but **falling EUA prices and rising geopolitical risk have shifted the advantage to lignite** (more strongly) and coal (to a lesser extent) **from March onwards**

2026 v 2025: Forecast (May-Jun), TWh



- **Renewables drive the balance into year-end**, with wind recovering if conditions normalise and **solar output rising on capacity growth (+13% y/y)**
- **Nuclear output edges lower**, reflecting **upgrade work in Belgium** and **higher modulation in France**
- **Gas generation falls sharply y/y**, while **coal and lignite broadly hold**, driven by stronger renewables and weaker gas economics, **with uncertainty around gas prices into year-end**
- **Demand growth remains modest (+1.3% y/y)** and is **outpaced by supply gains**, keeping the system **overall looser than last year**



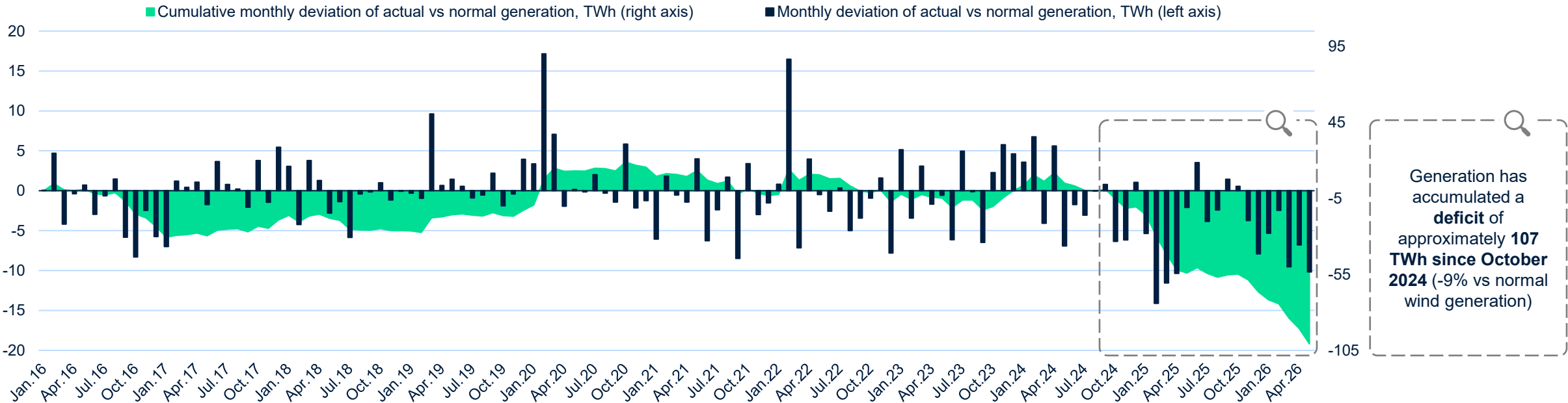
Weather impact

Wind trends and El Nino



107TWh lost: why European wind is falling short of its potential

European wind: monthly deviation of actuals vs normal generation, TWh



① **Grid & Economic Curtailment**

- Record curtailment in 2025 across Spain, Germany, France & Great Britain

② **Wake Effects**

- Dense offshore clusters lose 10-20% of output to intra- and inter-farm wake

③ **Ageing Turbines**

- Repowering is gradual – smaller turbines are replaced with fewer, larger units

④ **Meteorological: Jet Stream Blocking**

- Likely cyclical, not structural. 2025 'blocking' patterns are the primary near-term driver

Structural headwinds persist

- Curtailment, wake losses and turbine ageing compound as capacity grows
- These factors add structural upside risk to far-curve power prices

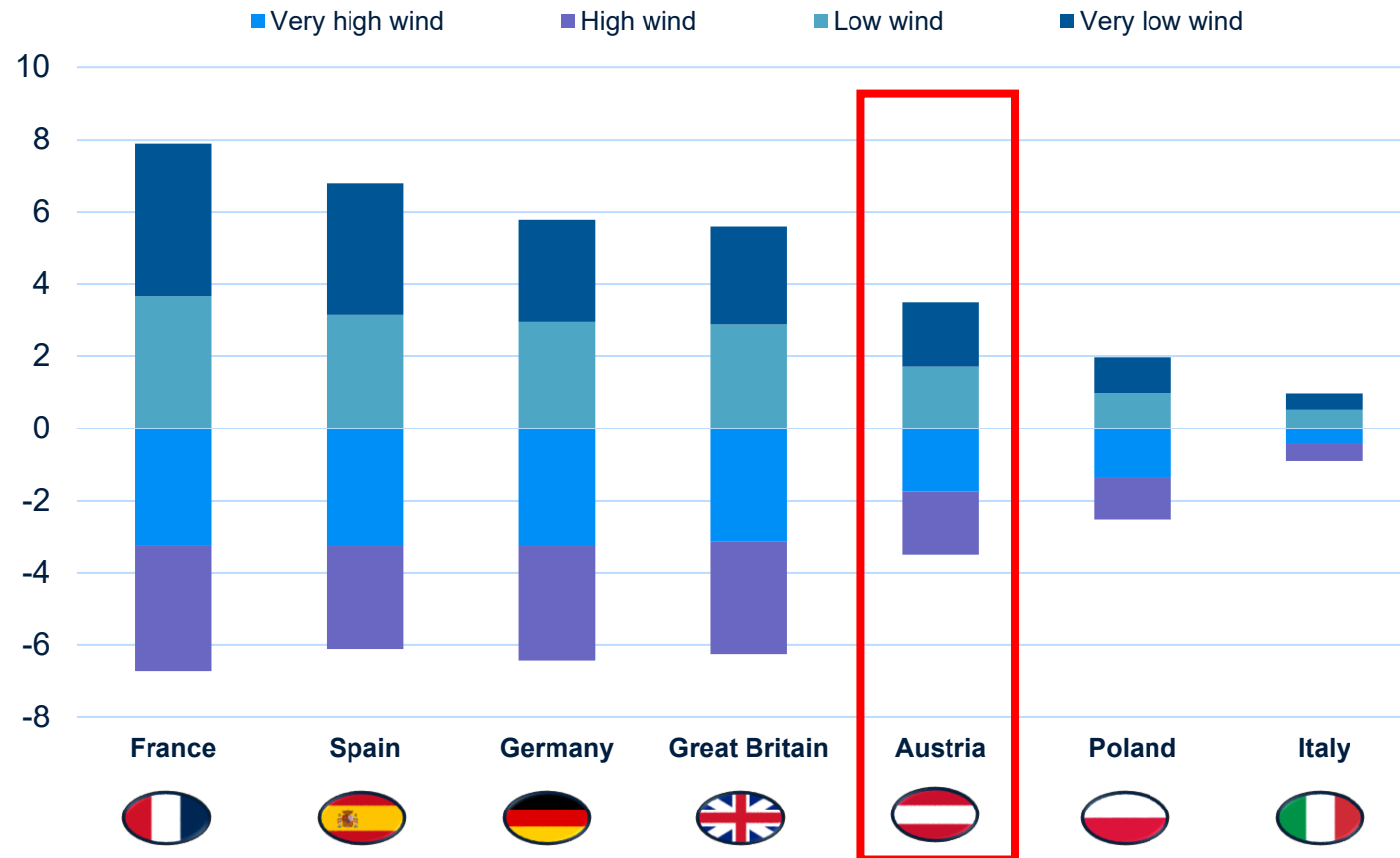
Meteorological weakness likely cyclical

- Jet-stream blocking drove 2025 underperformance
- A return to seasonal norms would press near-curve prices and gas burn lower; key watch: Q3-26



Scenario analysis shows wind price impacts and risks are market-specific, not uniform

Impact of wind variability on power prices over the next 12 months
(variation vs baseline), €/MWh



Scenario design

- **Wind scenarios** set at $\pm 6\%$ and $\pm 12\%$ vs normal load factors, reflecting historical tail outcomes
- Calibration based on 2016–2023 wind data using 12-month rolling deviations; **sustained extremes reached -11% low wind and +8% high wind**, supporting $\pm 12\%$ tails and $\pm 6\%$ central variability



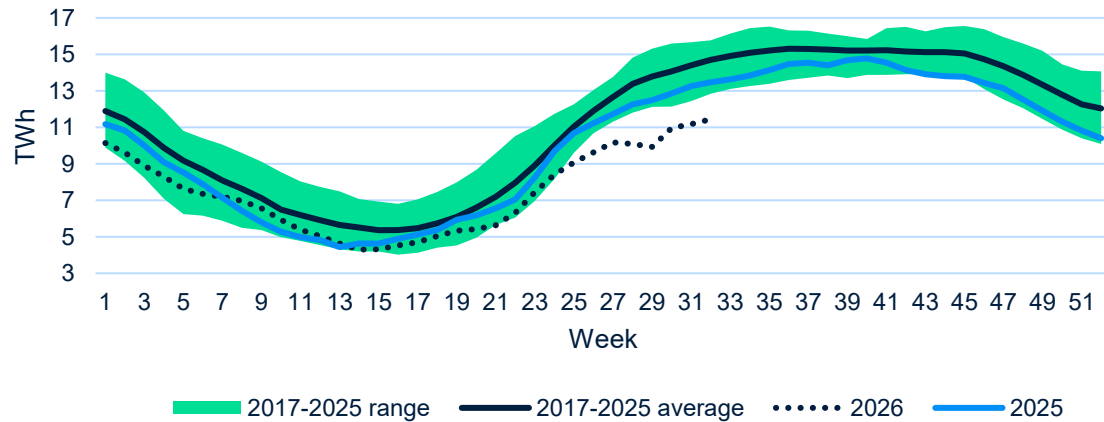
Price impact

- **France and Spain** show larger upside risk: low prices, frequent non-gas price setting, steep merit order; **low wind quickly pushes gas to the margin**
- **Great Britain and Germany** show downside skew: gas often marginal even in low wind, while high **wind enables decoupling from gas**
- **Austria** imports the price impact from Germany **limited by x-border connection**
- **Poland and Italy** remain weakly responsive, with **low wind penetration** rarely affecting price setting
- **Technical constraints consideration**: price risk skewed to the **upside** due to extra-model constraints; extreme high-wind generation is unlikely to fully materialise **given grid limits and turbine shut-downs**

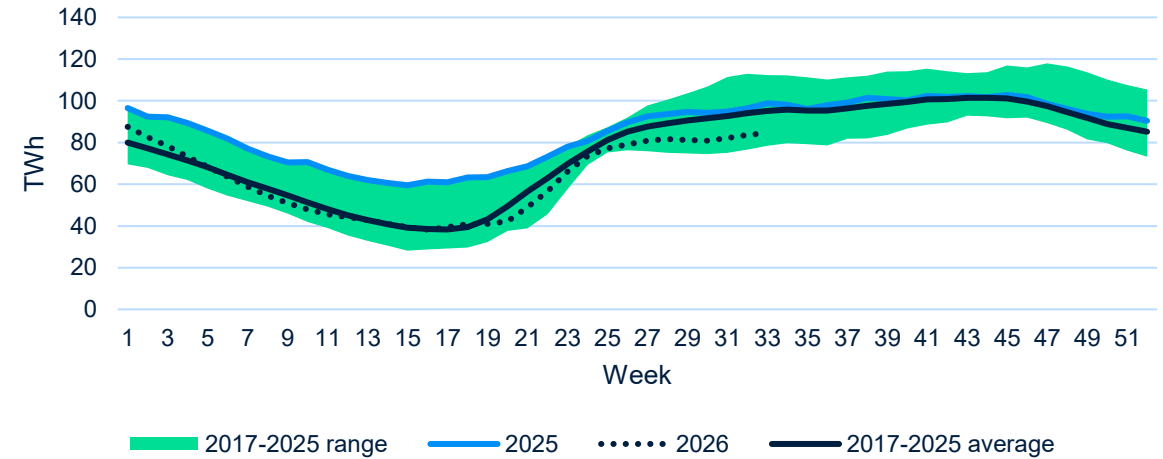


Hydro stocks in a poor position ahead of winter

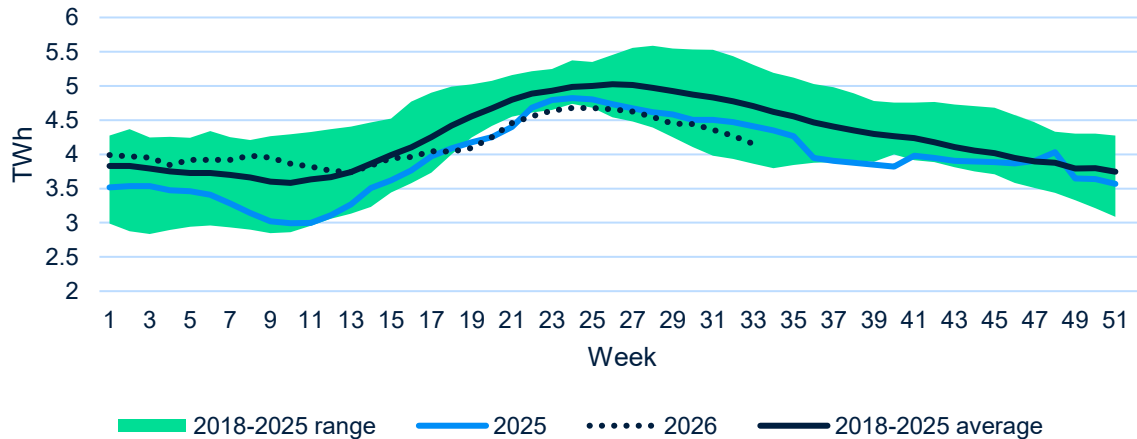
Aggregated reservoir stocks - Alps



Aggregated reservoir stocks - Finland, Norway and Sweden



Aggregated reservoir stocks - Balkans

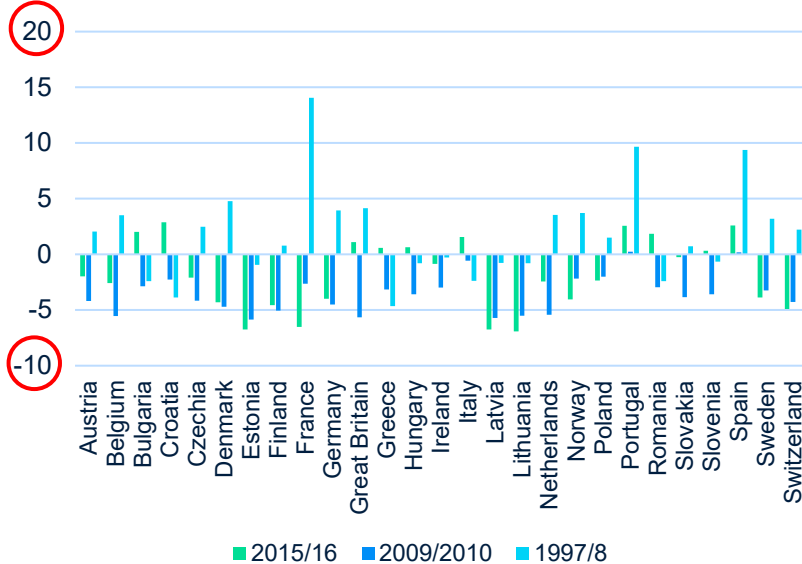


- **Hydro reservoir stocks below normal** across Europe and **especially poor in the Alps region** where they are at **historic lows**
- Both **reservoir and run of river generation** are seeing a **similar pattern**
- Dry weather expected to continue for the rest of September, **worsening the stock levels as we enter winter**
- The outlook beyond September is uncertain, but **hydro concerns are a major source of risk premium being priced into the market**

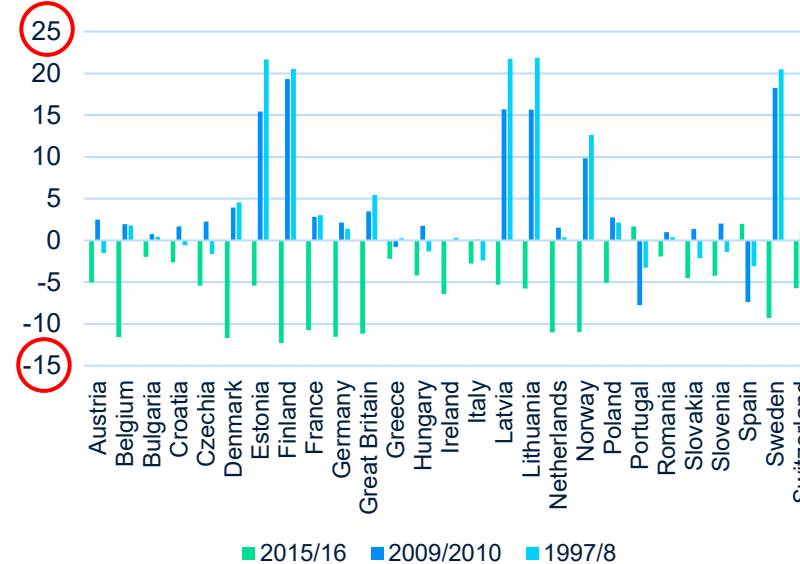


What impact can we expect from a strong El Niño?

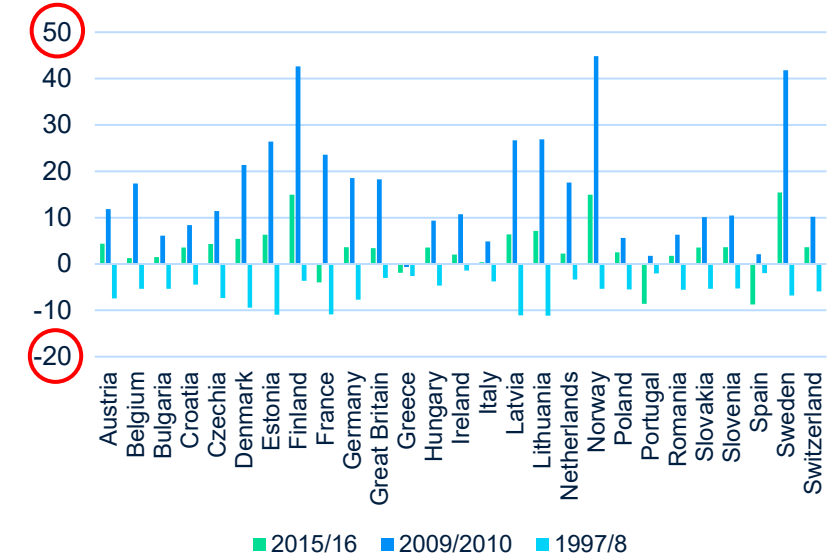
Change in European power prices vs
Base Case (Q3 2026) €/MWh



Change in European power prices vs
Base Case (Q4 2026) €/MWh



Change in European power prices vs
Base Case (Q1 2027) €/MWh



- **Higher than average solar generation** highly likely across Europe in Q3
- Risk of increased demand and **below average hydro**
- Risk of continuing **low wind speeds**

- Traditionally strong **El Niño** is associated with a **mild start to winter**, suggesting below average demand in Q4, though the data from **strong El Niño events do not fully support this**
- **Improving hydro stocks** likely
- Risk of **continuing low wind speeds**

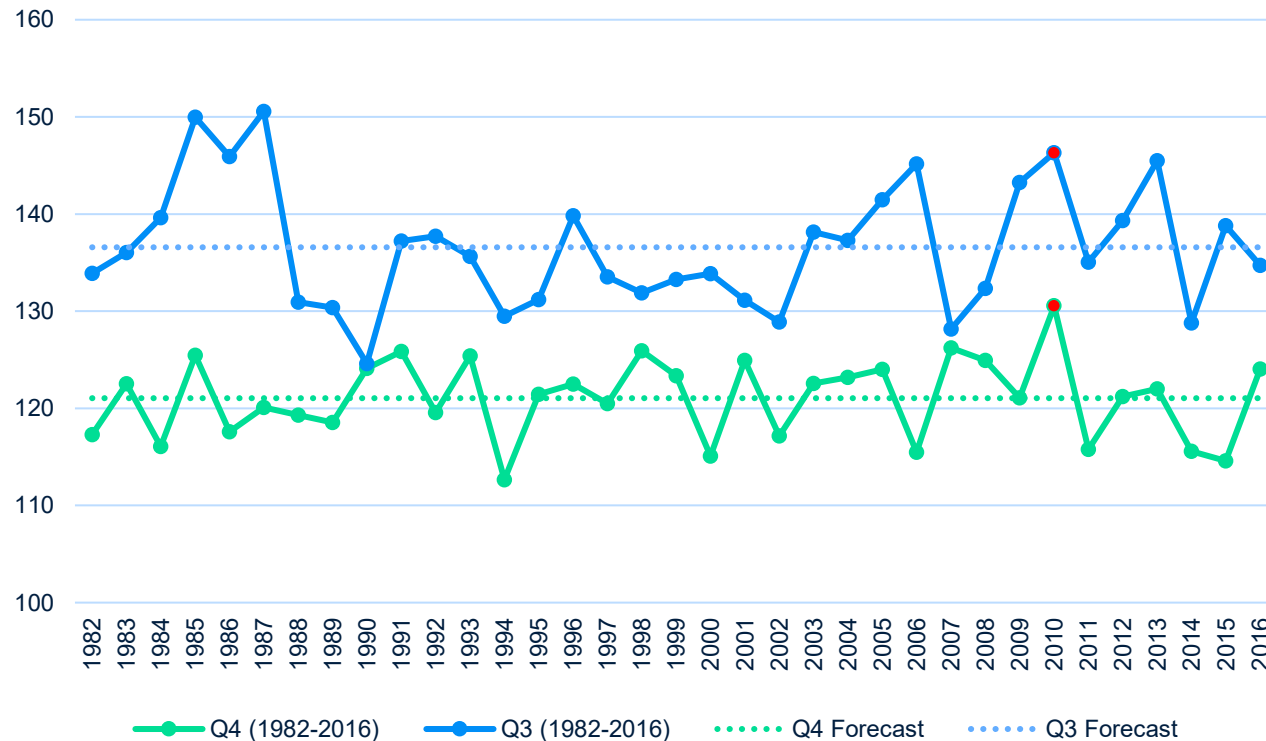
- **Risk of cold weather** leading to increased demand and prices, though **historical strong El Niño events don't all fit this pattern**
- Potential for **increasing wind speeds**
- Potential for **reduced hydro stocks**
- **Scenario: Austria power price increase using 2009/2010 weather: €11.81/MWh**



Temperatures a key two-way risk for winter, especially in France



French winter demand can vary by up to **35TWh** this winter based solely on temperatures



- **Temperatures remain a major driver of prices over the winter period**, with cold weather leading to **expensive gas plants having to fire up**.
- While individual months have been cold in recent winters (i.e. January 2026), **Europe has not experienced a significantly cold winter since 2009/10**
- However, we are currently experiencing a **strong El Nino** (which was also the case in 2009/10). This **increases the probability of a cold Q1 2027**, with the market seemingly **pricing in this risk**
- The **power price impact of temperatures varies considerably across countries**. **France** (which has a lot of electric heating) is most at risk (both upside and downside), **with a 35TWh swing in power demand for winter**, based on 35 years of historical weather data.

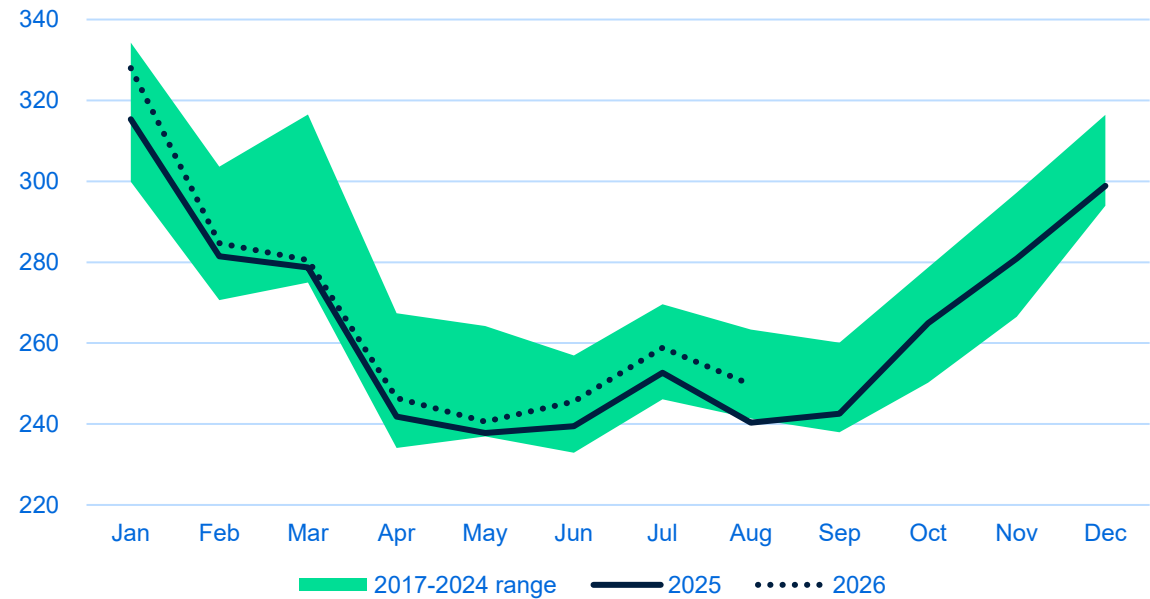
Overall **Austria** power demand is forecasted to be:

- '26Q4: 19.2TWh
- '27Q1: 20.0TWh



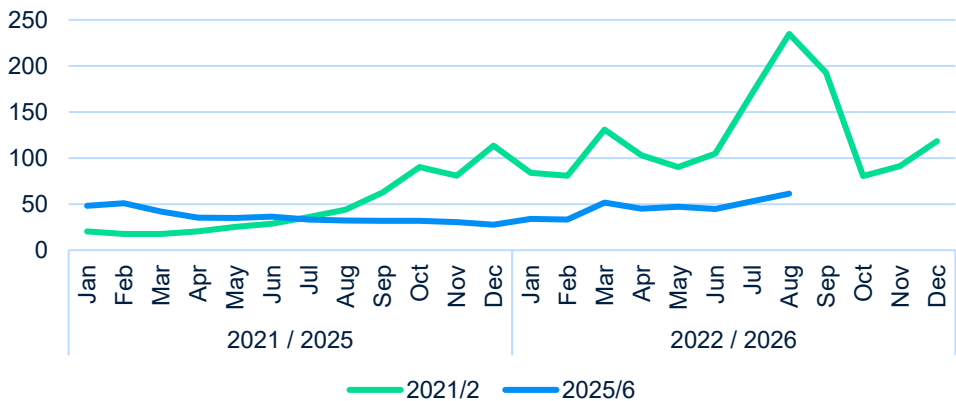
Demand increasing despite higher prices

European¹ monthly electricity demand, TWh

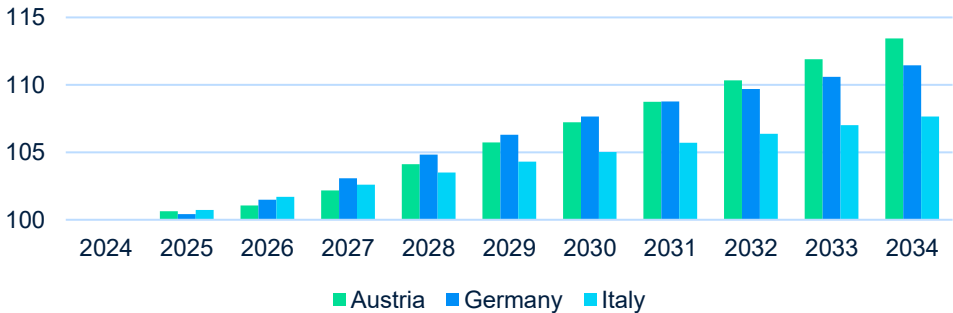


- After the gas crisis, European power demand plunged in 2022 and 2023 (around -3-4% y/y in both years), while 2024 marked the first year of recovery (+1.3% y/y)
- After the post-crisis rebound, power demand growth faded in 2025, ending the year at just +0.4% y/y
- Since the start of winter 2025-26, EU demand has re-accelerated to around +1.5-2% y/y, supported by the coldest January since 2010 and the hottest summer ever

Another fuel price shock?: TTF price history, €/MWh



Economic growth: GDP per Capita real terms, PPP adjusted, 2024=100²



1. Europe is defined as EU27+ GB+ CH + NO; 2. ICIS demand index is a rolling average of temperature-adjusted demand in previous 3-months, compared to same period in previous year; Sources: ENTSO-E, ECMWF, 2 Oxford Economic (as of 8 Sep '26); Sources: ICIS analysis



Regulation impact

Italian energy decree and cross
border capacity



Italian energy decree – the original proposal: offset impact of carbon costs

DL bollette – Art.6: The measures

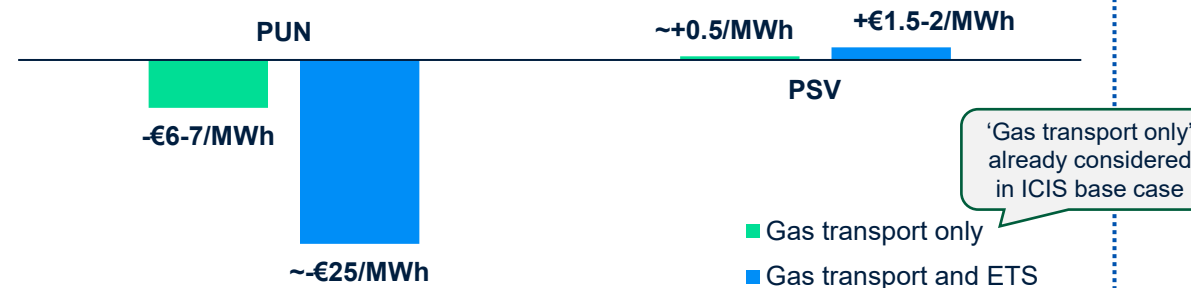
“Comma 2” – Gas transportation tariff reimbursement

- Reimbursement of variable components of approximately €5/MWh during the winter period and around €3/MWh in summer
- Effective from 1 January 2027
- ✓ Law conversion completed (April 2026)
- ⚠ Operational implementation delegated to ARERA (consultation ongoing, final rules expected by end-2026)
- EU status: not formally notified as State aid; ex-post challenge risk remains but no standstill → measure proceeding

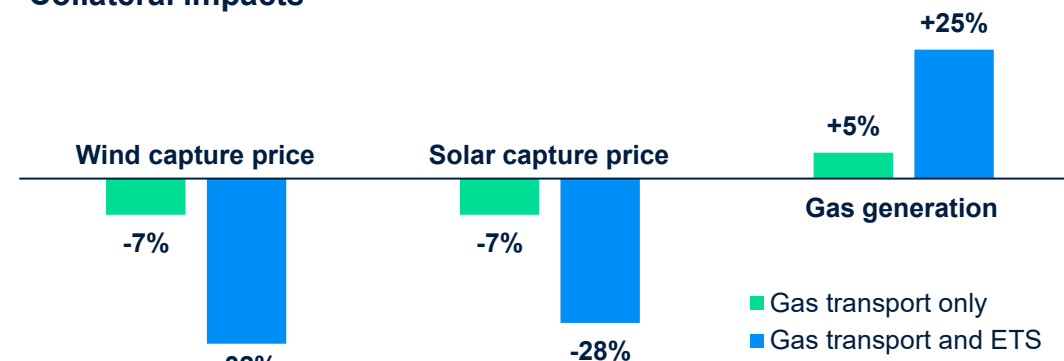
“Comma 3” – ETS cost reimbursement

- Partial carbon cost reimbursement for gas-fired generators, capped at efficient CCGT level
- Effective from 1 January 2027 (subject to EU approval)
- ⚠ Notified to European Commission as State aid → mandatory standstill
- EU status: procedure opened; standard timeline 2 months (quick decision) or up to 18 months (in-depth investigation). Commission concerns:
 - Absence of sunset clause (non-temporary measure)
 - Distortive impact on cross-border trade (IT highly interconnected vs Iberian precedent)
 - No EU precedent for ETS reimbursement to fossil generators
- ICIS view: approval highly unlikely in current form

Impact on energy prices



Collateral impacts



Timeline



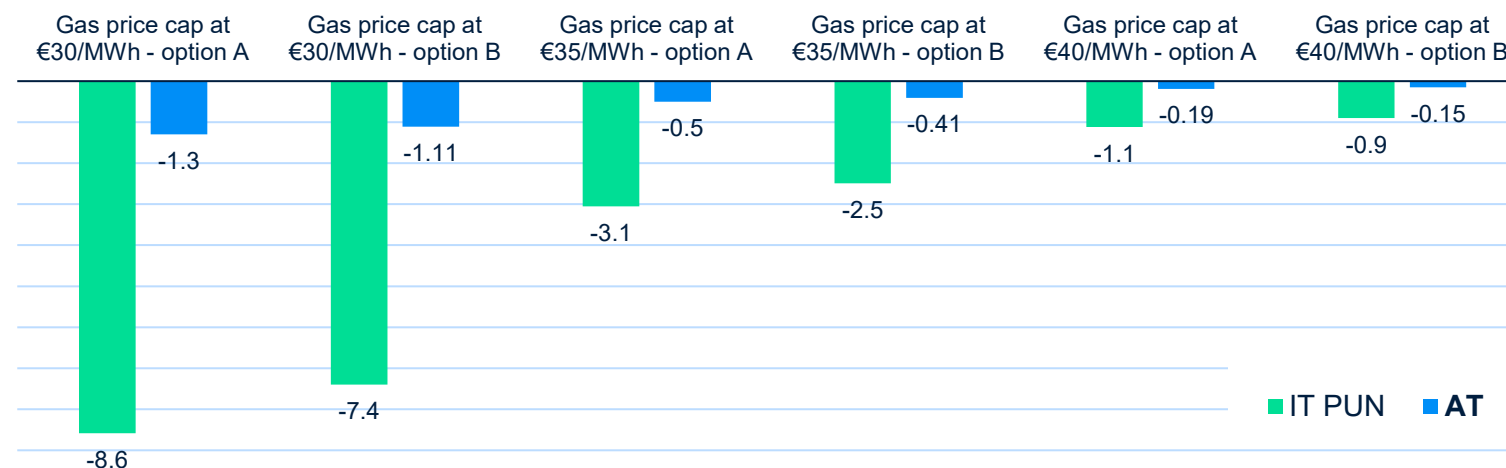


From ETS reimbursement to the “Scudo Italiano”: a redesign aimed at improving approval prospects

What the latest version proposes

- Replaces the original ETS reimbursement concept with a **temporary gas price cap mechanism**
- Inspired by the Iberian “tope”**, previously approved by the European Commission
- Gas-fired generators receive compensation** when PSV exceeds a conventional gas-price cap
- ARERA¹ proposes **two implementation options**: a more aggressive design (Option A) and a more conservative design (Option B)
- Option B preserves part of the gas-price signal**, reducing reimbursements and limiting market distortions
- Monthly minimum cap levels designed to constrain the impact on cross-border flows** (based on 2024-25 spreads and only on FR, AT and SI borders)
- Final cap calibration subject to discussions** between ARERA, the Italian government and the European Commission

Potential impact on power prices (2027 vs base case)², €/MWh



- We modelled six scenarios** for 2027, combining **three gas price cap levels** – €30/MWh, €35/MWh and €40/MWh – **with the two implementation options** outlined by ARERA
- Only a **€30/MWh cap delivers a material year-round impact**, reducing the annual PUN by €7.4-8.6/MWh depending on the implementation option
- A €35/MWh cap primarily acts as a winter-relief mechanism**, lowering annual power prices by €2.5-3.1/MWh while having limited impact during the rest of the year
- A €40/MWh cap** — the most realistic scenario and broadly consistent with the initial Iberian cap level — **reduces the annual PUN by only ~€1/MWh** under current forward gas-price assumptions
- Under current market conditions**, a **€40/MWh cap functions primarily as a safeguard against future gas-price shocks** rather than as a tool to materially reduce wholesale power prices

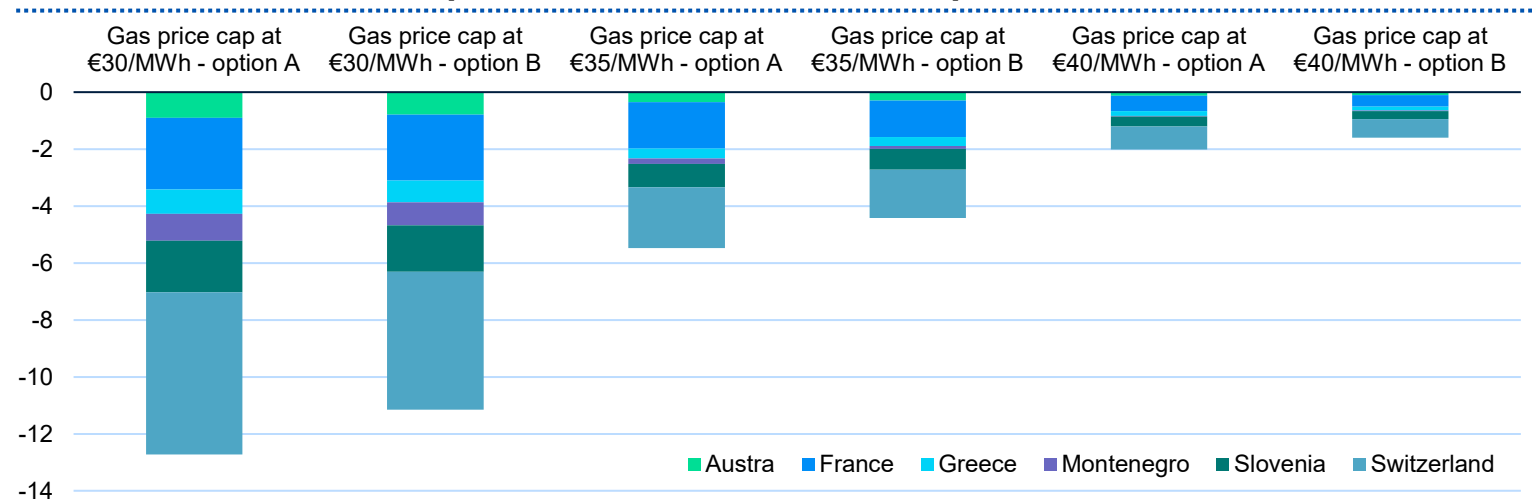


The redesign improves approval prospects, but significant trade-offs remain

Why the proposal remains problematic

- **Complex mechanism** requiring monthly cap calibration, reimbursement payments and **continuous monitoring**
- Effective generation costs become partly **dependent on regulatory decisions rather than purely market signals**
- **Reduced forward-price visibility** and lower hedging certainty for market participants
- **Risk that ex-ante calibration does not reflect actual market conditions during delivery**
- Mid-month cap revisions improve flow control but may **reduce market predictability**
- **Higher gas prices** would increase the effectiveness of the mechanism, but also **amplify cross-border distortions**
- **Repeated redesigns** of the measure risk increasing perceived regulatory uncertainty for investors and market participants

Potential impact on Italian flows - Net import reduction¹, TWh



- The key trade-off remains unchanged: **lower power prices require lower imports**
- **Net imports decline by 11-13TWh under a €30/MWh cap**, versus 4-6TWh at €35/MWh and only 1-2TWh at €40/MWh
- **Switzerland accounts for 40-45% of total import displacement** in the most aggressive scenarios
- **ARERA excludes Switzerland from its cap-calibration methodology** because it is not part of the SDAC framework; only France, Austria and Slovenia are considered
- The redesign reduces – but does not eliminate – cross-border distortions
- The same safeguards that **improve approval prospects** also **reduce the mechanism's effectiveness** in lowering power prices

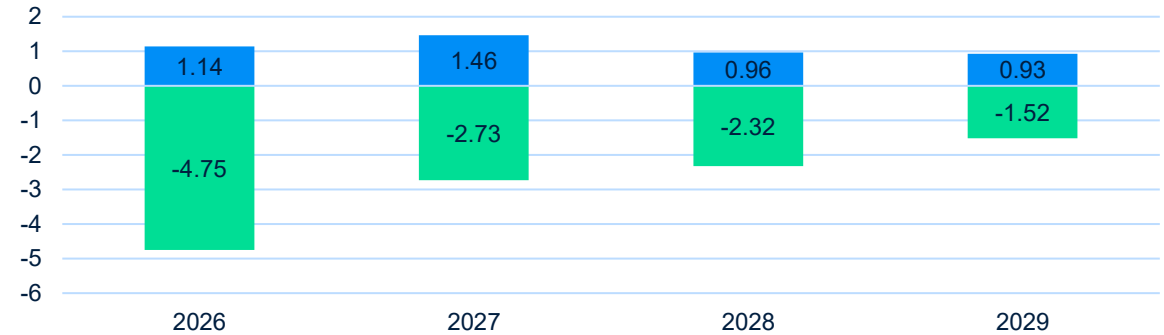


Grid development and restrictions between Germany and Austria, a difficult situation and no near-term solutions

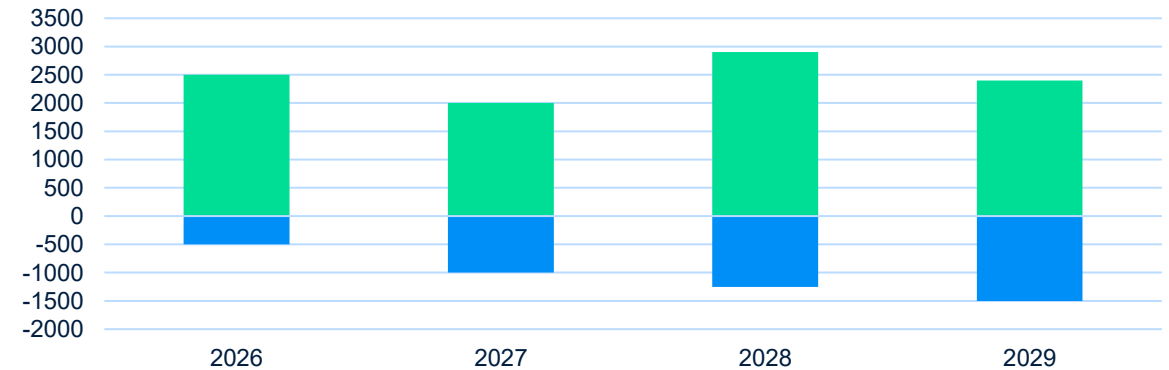
- Since June 2022, both **Austria and Germany are part of the Core FBMC system.**
- The FBMC dynamic algorithm calculates actual physical grid constraints across the whole area. **Power flows have reduced since then.**
- A **German market split is currently not foreseeable** although from an Austrian perspective very reasonable. High wind generation in the north of Germany is causing loop flows and high redispatch costs.
- TSOs like APG and TenneT working on reinforcement projects.
- 3 scenarios: if more capacity would be available in practice, what would be the price impact for Austria.



Price impact, if available transmission capacity to Germany would increase or decrease, €/MWh



Deltas of available export transmission capacity from Germany to Austria, MW



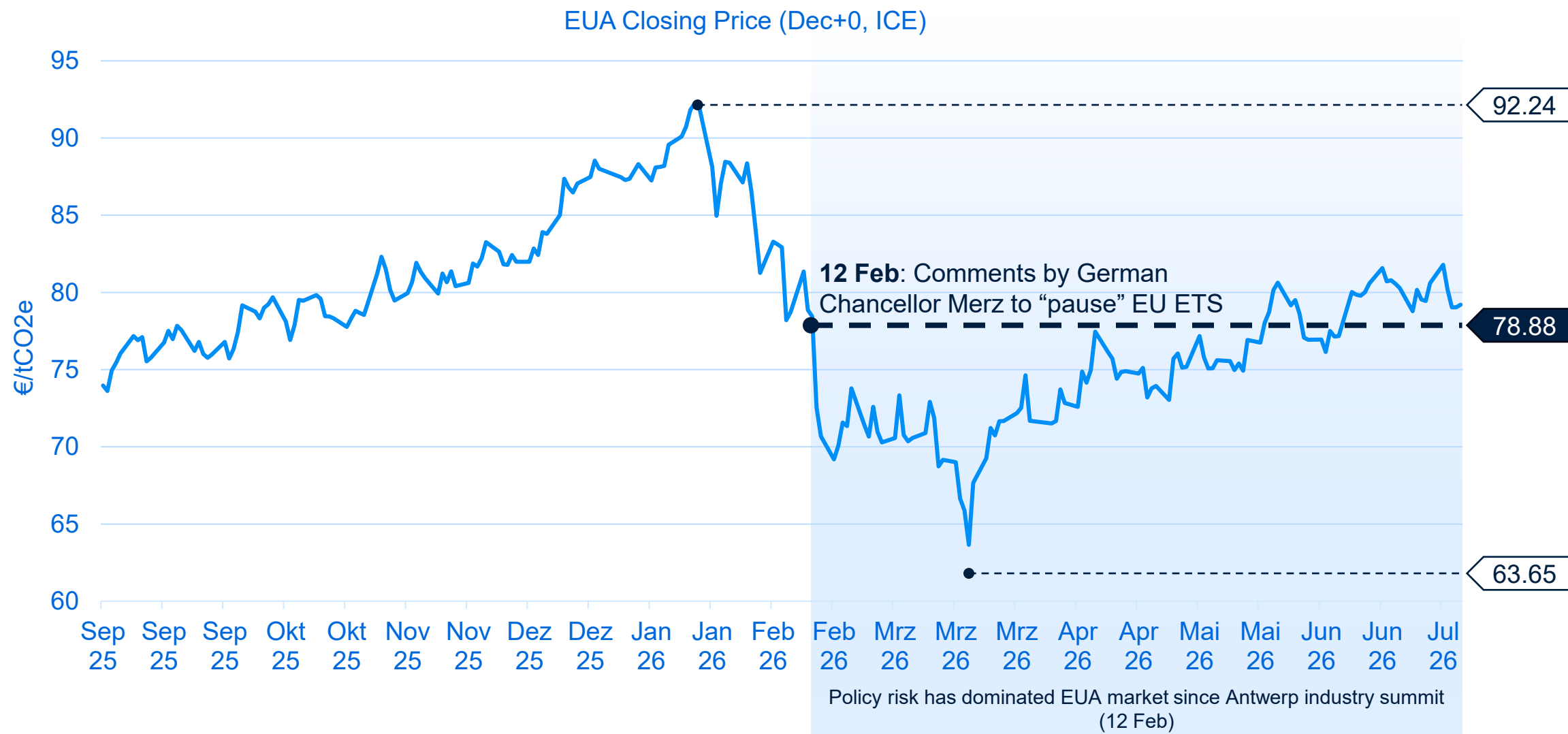
Carbon price impact



key risks and price expectations



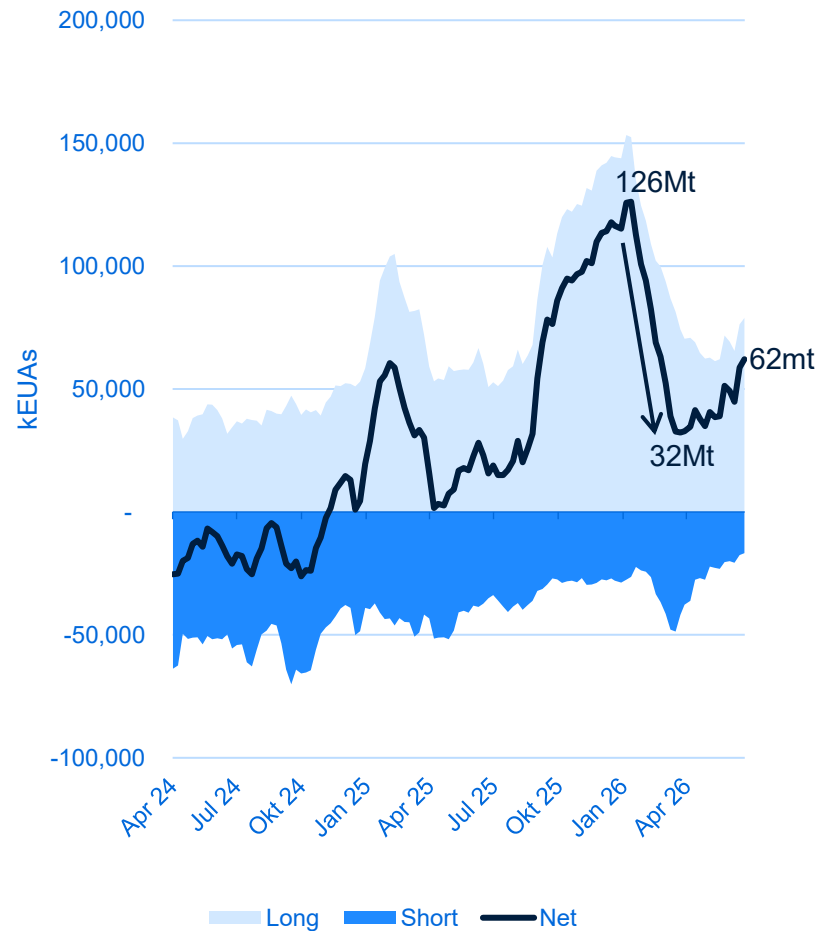
EUAs have recovered losses following the “infamous” comment from German Chancellor Merz





Speculators cut net length but retain bullish bias on EUA positioning

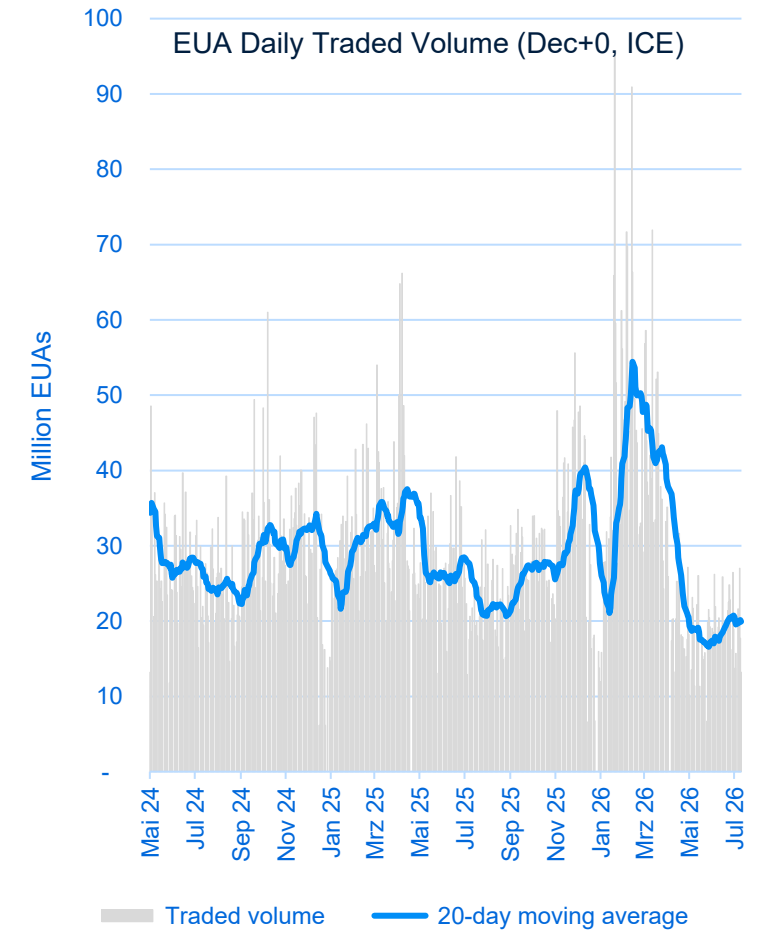
1) Funds cut net length by >90Mt, now rebuilding



2) No meaningful build-up of EUA shorts, length is stretched



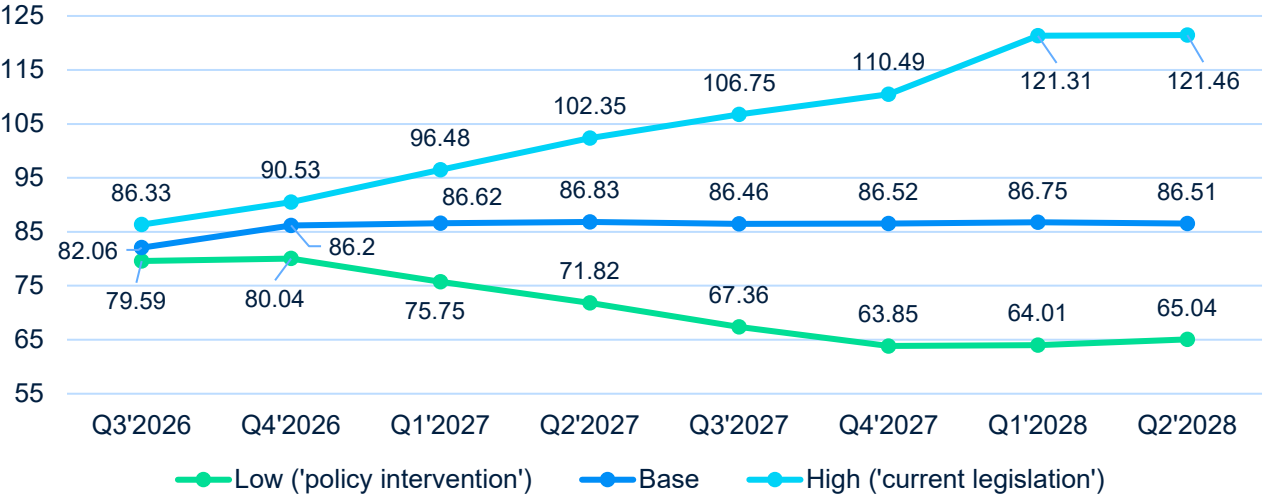
3) Sharp drop in traded volumes reflects a fatigued market



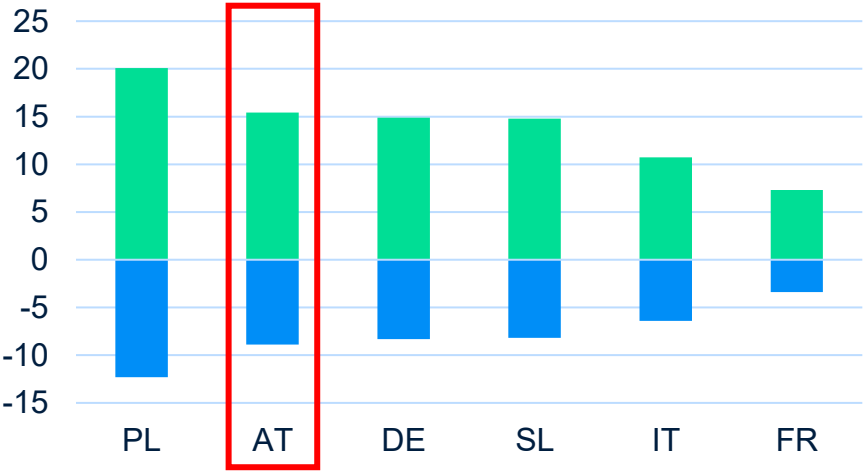


Policy intervention risk ahead of the July EU ETS review drives wide EUA price scenarios, spilling over into power prices

ICIS EUA price forecast (mid August 2026), €/tCO2 real



Power price impact on Cal-27 vs Base Carbon Scenario², €/MWh



Three scenarios driven by two levers:

- Fair value (speculative behaviour)
- Policy mix (supply-side rules)

- 1 Base case**
 - Price expectations capped by a **politically acceptable ceiling (<€100/t)**
 - Speculators unwind earlier**, selling emerges around €80–85/t
- 2 Low (additional supply)**
 - Stronger intervention risk embedded
 - Lower fair value + extra auctioned supply** (+90Mt post-2028)
- 3 High (current legislation)**
 - No policy intervention** assumed
 - Prices anchored to **industrial MACs**, speculators stay long **above €100/t**

- Near term (2026):** fundamentals remain **structurally tight** → Price trajectory driven by **speculative positioning**, not emissions
- Carbon remains** a key **driver** where fossil plants set prices
 - Higher EUA paths **lift power prices most in coal- and lignite-exposed markets**(e.g. Germany, Poland)
 - Lower exposure markets (**Spain, France**) show more **muted price sensitivity**
- Overall, carbon-driven **price risk is asymmetric**, market-specific, and policy-dependent



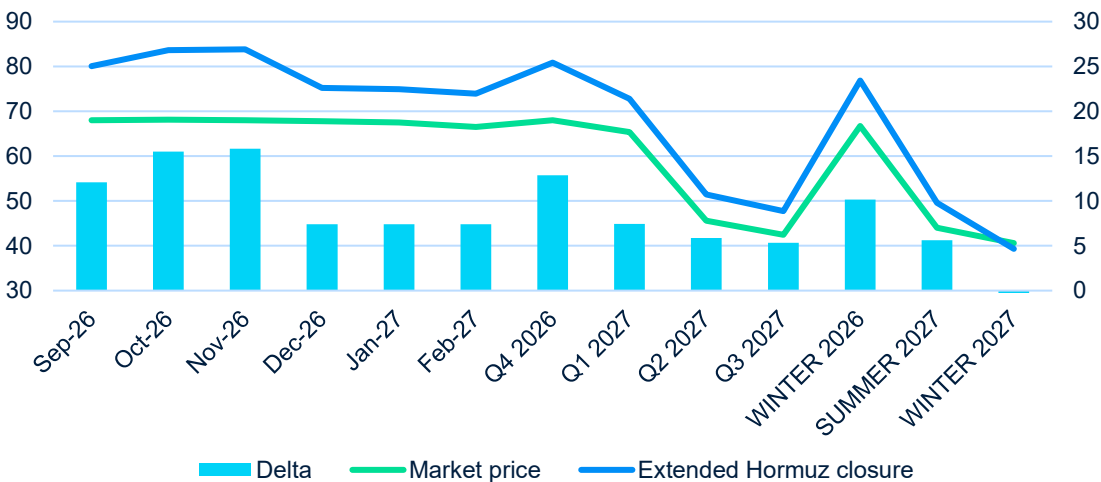
Gas prices

Geopolitical risks drive uneven spillovers into power prices



How much higher could gas and power prices go?

TTF forward curve vs Extended Hormuz closure until 27 March³, €/MWh



- If Hormuz remains closed for the whole of winter, we see **gas prices rising by another €7-13/MWh** for Q4 and Q1
- The **impact of this on power prices** varies across markets, with **GB and Italy the most exposed** (+€12-25/MWh for winter contracts)
- If we were to **also see a cold winter**, gas prices could **increase by a further €10/MWh**,
- Therefore, while we think power markets are **overvalued at current gas prices**, we see a **high probability of prices increasing in absolute terms over the coming months**

Market consensus on the probability of Hormuz traffic returning to normal, by date²:

- 31 December: 23%
- no return in 2026: 77%

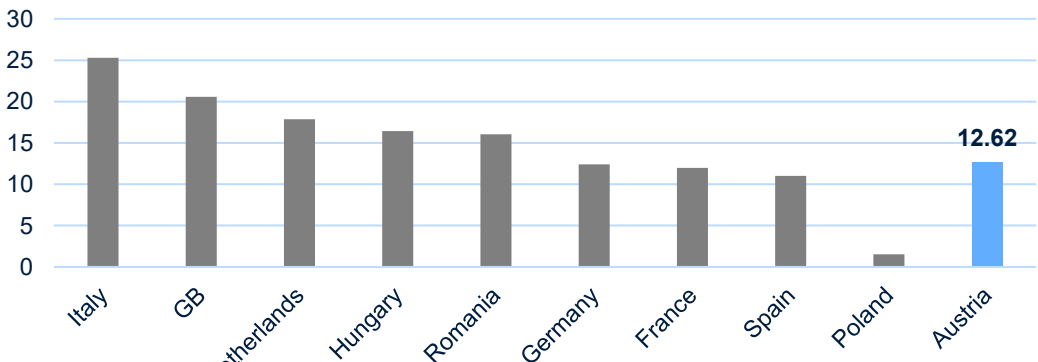
As of 8 Sep

Market consensus on the probability of Hormuz traffic returning to normal, by date¹:

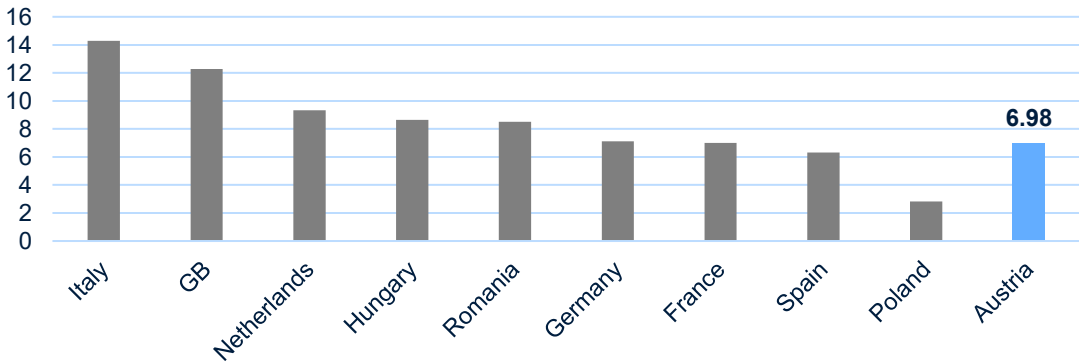
- 30 Jun 26: 20%
- 31 Jul 26: 39%
- 31 Dec 26: 76%

As of 3 June

Hormuz extension price impact vs Base (Q4 2026), €/MWh



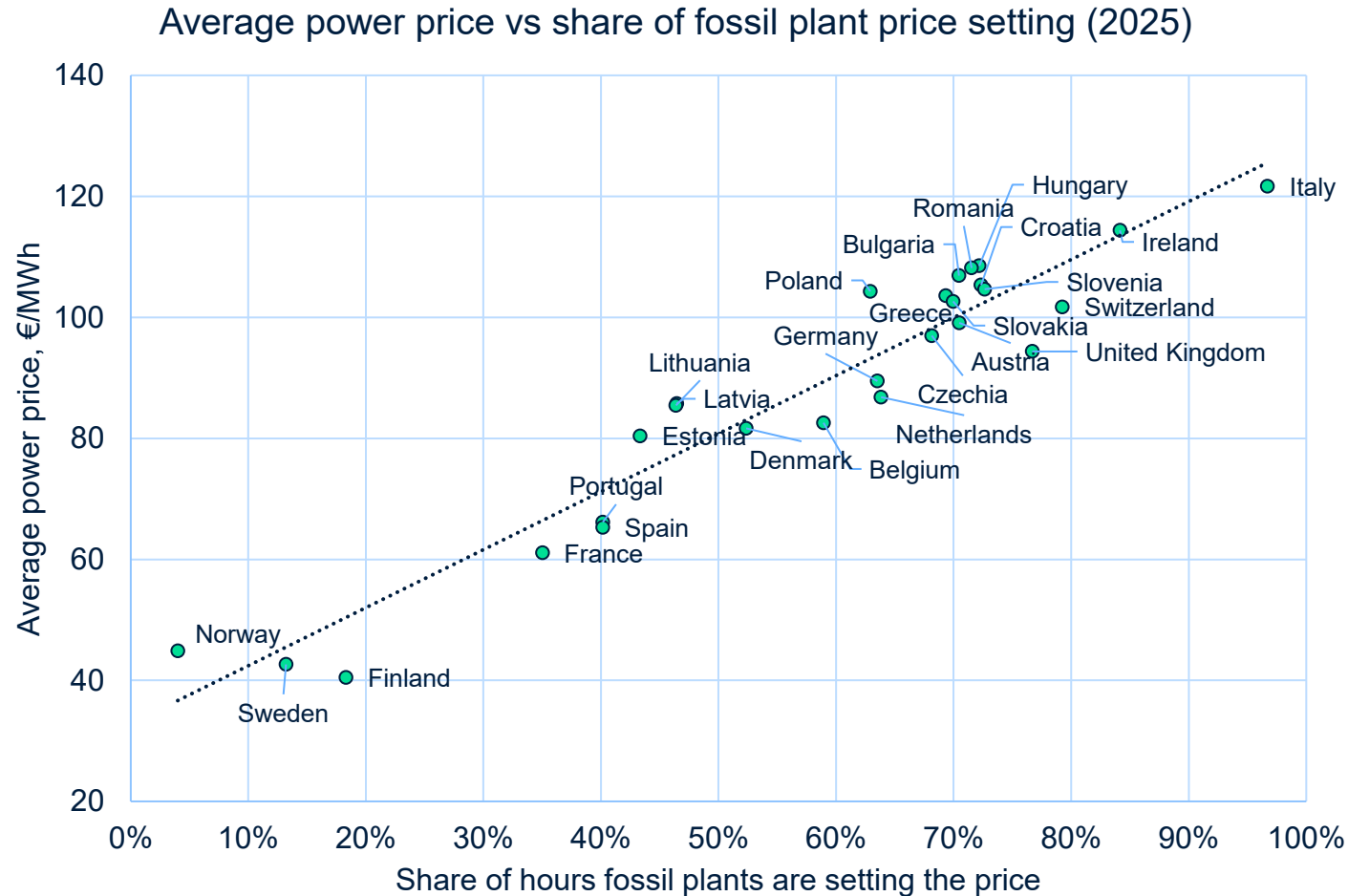
Hormuz extension price impact vs Base (Q1 2027), €/MWh



1. Based on Polymarket data (as of 3 June26); 2. Based on Polymarket data (as of 8 September); 3 Gas Foresight; Sources: Power Foresight



Wholesale prices are closely correlated with the share of fossil price setting



- There is a **close correlation** between **the percentage of hours in which fossil plants set the price** and the **average wholesale price level**
- The methodology does not allow us to exclude coal and lignite, but outside of a few markets (DE, PL, CZ) **the vast majority of fossil plant price setting comes from gas**
- Therefore, the **ability of each country to reduce its wholesale price level** is largely determined by the extent that it can **reduce the hours of gas price setting**.
- **The Nordics, along with France, Spain and Portugal,** stand out for having the **lowest shares of fossil plant price setting and the lowest wholesale prices**
- If calculating **total system cost** (subsidies, grid management, etc.) the **relationship between gas price setting hours and costs is far more complicated**

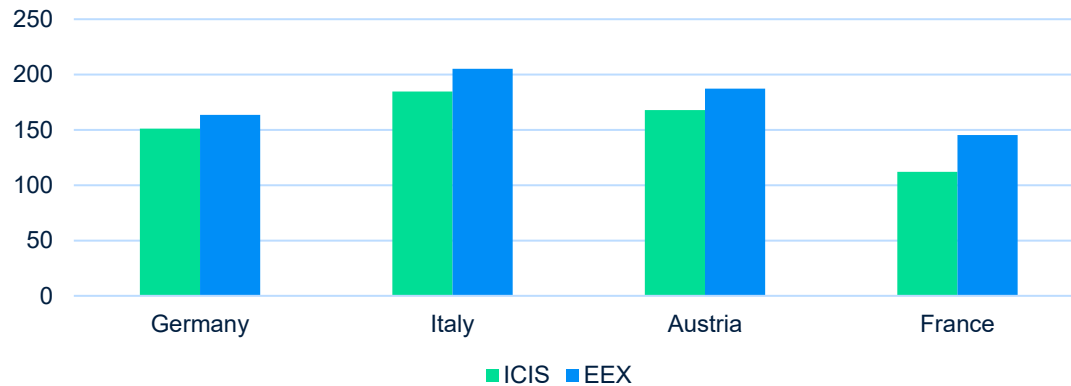


Market outlook

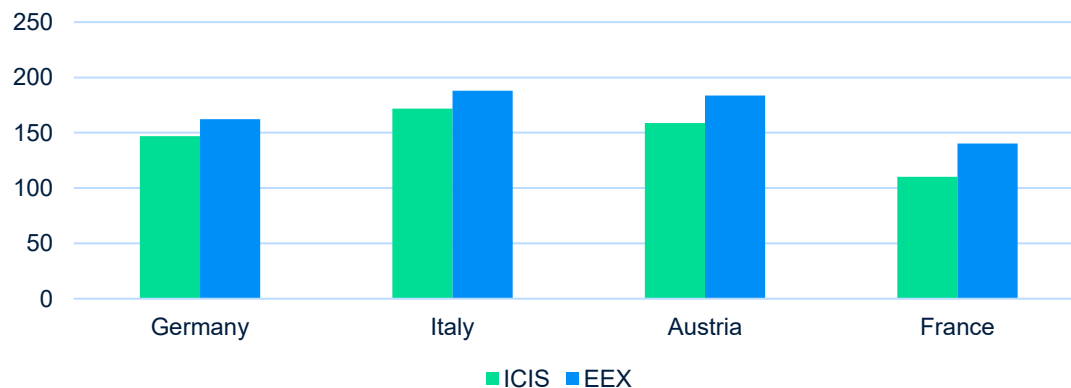


Are power curves being overvalued for winter?

ICIS forecast vs EEX prices (Q4 2026)²



ICIS forecast vs EEX prices (Q1 2027)²



- We see a similar pattern across almost all European countries, with **market prices currently above our fundamental forecast prices**
- **Average risk premium** across markets increased from **€5/MWh for Q4 2026** and **€10/MWh for Q1 2027** some weeks ago to €10-30/MWh
- This risk premium stems from the perceived risks of:
 - **Poor hydro generation**
 - **Continuing below-average wind speeds**
 - **Cold temperatures**
- These are all two-way risks. We see **markets as being overvalued from a purely fundamental perspective.**
- The **biggest uncertainty: gas prices**. This **upside gas risk** accounts for **much of the risk premium** we see across markets at present
- While gas price risk primarily shows up in the gas price itself (and entirely within our forecast, which uses market prices for gas), **some market participants are pricing in additional gas price risk into power futures**
- Speculation: Investment fund gross **long position** in **DE base contracts**, EEX, sums up to **50 TWh**, expressing a **bullish view**
- **All risks together could form a perfect storm, and the market is preparing for it!**



Where are power prices going next year?

Demand



- Limited downside risk in the short-term
- Increasing risk of demand destruction if Strait of Hormuz remains closed throughout the winter

Weather



- No evidence that recent low wind speeds are a meteorological trend
- El Nino increases risks of bullish Q1, but with fairly low confidence level

Gas Prices



- Massive two-way price risk
- Prices will drop sharply whenever a deal is announced
- However, substantial upside if strait will stay closed all winter

Carbon Prices



- Significant uncertainty over what the ETS reforms will bring
- Little appetite in Europe for high prices, so expect some intervention



	Insight	Hindsight	Foresight		
Gas	1-year price history	All price history	3-year forecast		
Power	1-year price history	All price history	Spot forecast	3-year forecast	2050 forecast
Carbon	Market data		EU ETS 2050 forecast	UK ETS 2030 forecast	ETS 2 2040 forecast
LNG	All history	Cargo tracking	2-year forecast		

ICIS Energy Portfolio

Thank you



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