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Electric Power & Natural Gas Practice

# Five trends reshaping European power markets

Utilities, traders, and large power consumers face significant challenges addressing the next normal.

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October 2021

**European power markets** have entered a period of unprecedented change. Power prices have touched new highs: baseload week-ahead prices have risen above €200 per megawatt-hour (MWh)[1] in a number of European countries—about four times the average historical level. That increase has been prompted largely by a surge in natural-gas and carbon prices, which currently exceed €100 per MWh[2] and €60 per metric ton, respectively. This development has affected the cost of power produced by natural-gas power plants, which broadly set prices in European markets.

At the same time, price volatility is reaching new heights as a result of the uncertain output of renewable assets and a tight supply-and-demand balance in the European power system. Navigating this next normal will be a key challenge for utilities, traders, and large power consumers, and that highlights the importance of developing resilient power-asset portfolios and managing risk.

In this article, we explore five trends that will shape the European power sector in the decade to come and offer some perspectives on how utilities and large consumers might respond.

## What's ahead for the European power sector?

The European power market is undergoing major changes. Five trends underpin these developments.

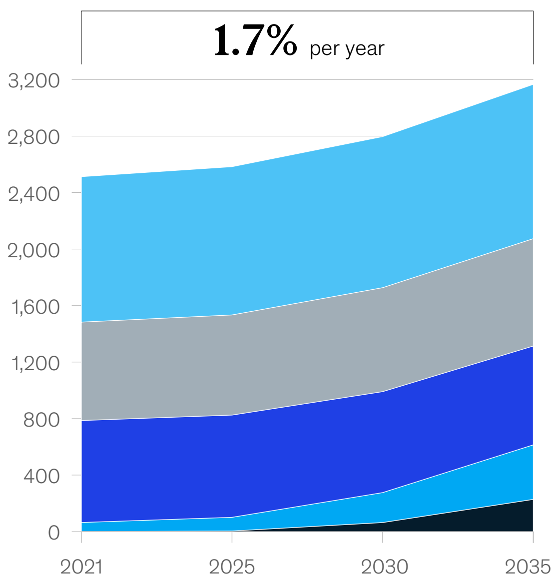
**Sustained growth in power demand, supported by climate-related targets**

Electricity demand is expected to increase steadily in Europe, at a CAGR of about 2 percent until 2035. The main factors behind the surge will be the

Exhibit 1

## Europe is expected to experience sustained growth in power demand through 2035.

**Forecasted power demand, by segment in main EU markets,**[1] terawatt-hours




| Key drivers | CAGR |
|---|---|
| **Industry:** Energy-efficiency measures and the electrification of industrial processes partly cancel each other out | 0.4 |
| **Residential:** Electrification of residential heating (heat pumps) and the increase and development of energy-efficient buildings partly cancel each other out | 0.6 |
| **Commercial:** Energy-efficiency measures lead to slight decrease in demand | –0.2 |
| **Transport:** National regulations, as well as the development of appropriate infrastructure, support the electrification of transport and multiple city bans on future internal-combustion-engine vehicles | 13.6 |
| **Hydrogen:** Strong uptake of green hydrogen production by electrolysis after 2030 leads to strong increase in power demand | 38.7 |

[1]Scenario: accelerated energy transition including hydrogen demand. Demand shown here excluding transmission and distribution grid losses, which are included in the power model. Main EU power markets (19 countries): Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden.
Source: "Global Energy Perspective 2021," January 2021, McKinsey.com

[1] Platts European Power Daily, S&P Global, spglobal.com.
[2] TTF (Title Transfer Facility).

electrification of transport and a ramp-up in the production of green hydrogen through electrolysis, requiring renewable power (Exhibit 1).

Transport power demand will grow by 14 percent CAGR as a result of the rollout of the electrification infrastructure and national regulations on emissions (for example, if cities ban internal-combustion engines and impose fiscal measures to discourage the use of nonelectric vehicles). The power requirements of green-hydrogen production will expand by about 40 percent CAGR, absorbing 230 terawatt-hours (TWh) of renewables output by 2035 across Europe—the equivalent of nearly a third of Germany's total consumption. Demand will grow only modestly in the industrial, commercial, and residential sectors because efficiency measures will mostly offset the electrification of industrial processes and residential equipment.

**A future energy system dominated by intermittent production, with uncertainty about total capacity rollout**

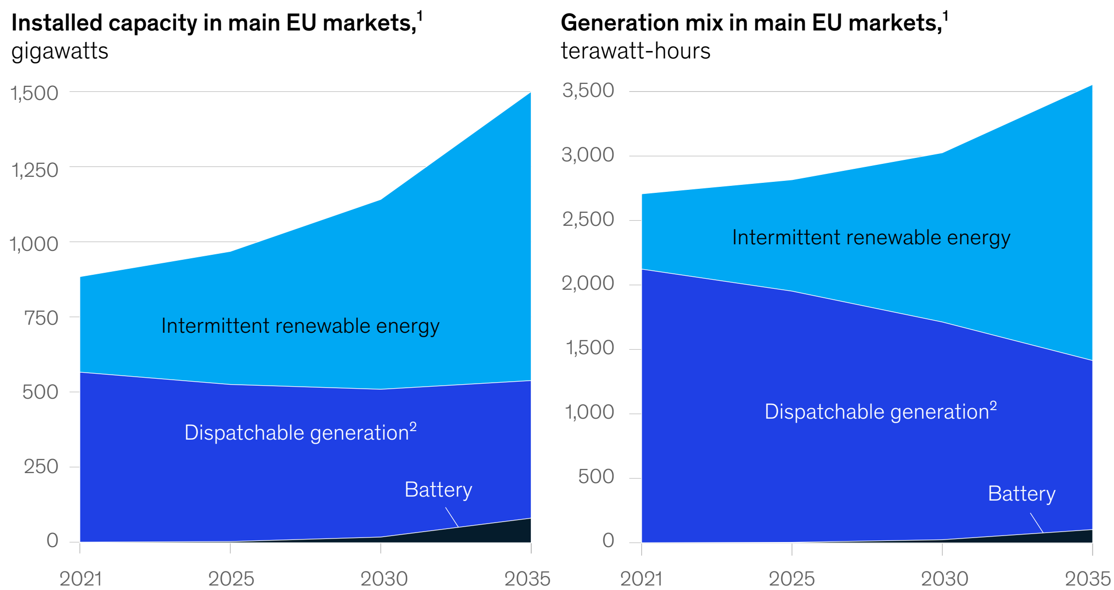
The expectation is that more than 650 gigawatts (GW) of intermittent renewable power, including wind and solar, will be developed from 2021 to 2035. Intermittent renewables will account for about 60 percent of total installed capacity in Europe in 2035, compared with about 35 percent in 2021 (Exhibit 2). However, it remains uncertain whether the pace at which renewables are rolled out will be sufficient:

— Project permissions have been delayed in a number of European countries. As a result, the gap between the time projects are proposed and commissioned is up to seven years.

— The modernization of the grid faces significant challenges as the production of renewable

Exhibit 2

**Intermittent production will dominate the European power sector.**




[1]Scenario: accelerated energy transition including hydrogen demand. Including transmission and distribution grid losses. Main EU power markets (19 countries): Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden.
[2]Including gas, coal, lignite, nuclear, biomass, hydropower, and others.
Source: McKinsey Power Solutions, EU power model, June 2021

power drives nodal imbalances, requiring utilities to invest in new transmission and distribution assets.

— Restrictions have been placed on the development of renewables assets in a growing number of countries—for example, limitations on onshore wind development as a result of concerns about biodiversity or noise and visual pollution.

**The phaseout of coal and nuclear assets**

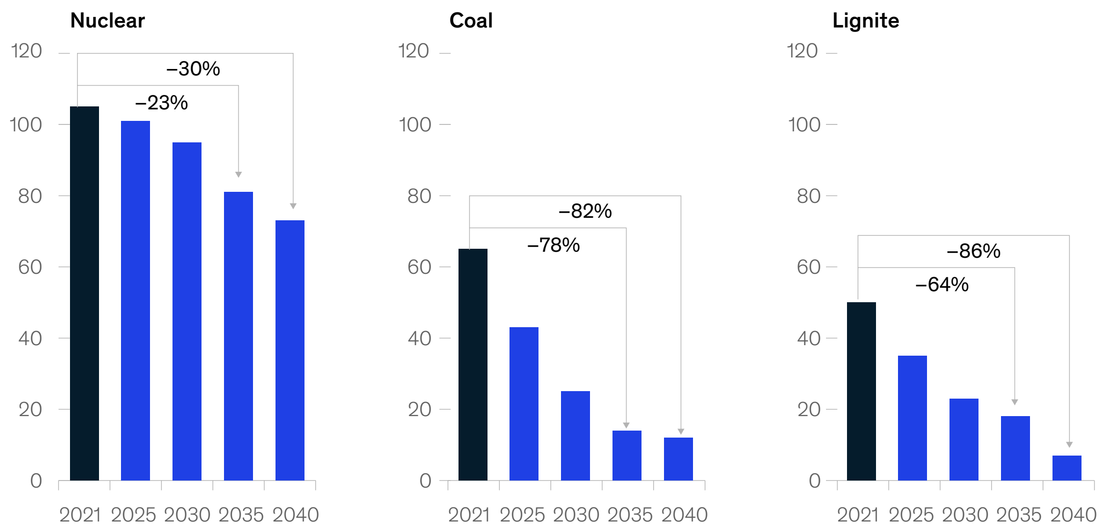
A large drop in dispatchable, or controllable, generation assets is expected because the use of coal is being phased out and nuclear plants are being decommissioned. This issue highlights the power system's reliance on weather-dependent renewables and on natural gas. Adverse wind and solar conditions or a slower pace of development for renewables could lead to power shortages. Gas prices may also fluctuate more, given the demand sensitivity of heating and the need for dispatchable power generation. In particular, European coal and lignite capacity will drop drastically—by about 70 percent from 2021 to 2035. Western and Northern European countries are taking the lead in these cutbacks.

Meanwhile, a number of EU countries are not renewing their existing nuclear-power assets and are making few new investments. Nuclear capacity is expected to decline by 23 percent from 2021 to 2035 (Exhibit 3). Germany, Belgium, and Spain have announced that they will close all their nuclear plants by 2022, 2025, and 2035, respectively. France has started closing its oldest nuclear plant while building a 1,650-MW new-generation reactor. The United Kingdom is developing a new 3,200-MW nuclear project, though delays and costs may hinder the further development of nuclear capacity there.

Exhibit 3

## A large drop in dispatchable generation assets is expected in Europe, caused by phaseouts of coal use and the decommissioning of nuclear plants.

**Capacity in main EU markets,**[1] gigawatts




[1]EU power markets: Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden.
Source: European Commission; Montel; S&P Global Platts; World Nuclear Association; McKinsey Power Solutions, EU power model, June 2021; McKinsey analysis

**The critical role of gas and batteries to bridge dispatchable-power capacity needs**

To ensure the grid's stability, the power sector must compensate for the drop in dispatchable assets. We expect new ones, such as natural-gas power plants and batteries, to partly balance the grid as coal and nuclear generation decline. More than 14 GW of natural gas are expected to come on line, mostly from 2021 to 2030, and more than 80 GW in batteries, primarily from 2030 to 2035. Yet a number of investments are contingent on national capacity mechanisms to avoid the risks of stranded assets for investors. Capacity mechanisms will also depend on compatibility with EU regulations and the EU's Fit for 55 package. Overall, natural gas is expected to remain a critical source of dispatchable power, especially in periods with prolonged low renewables output.

Declining battery-storage costs may encourage the rollout of batteries to alleviate the shortfall in dispatchable capacity. But the pace may be slower than anticipated, since European countries have not kick-started the industry with storage mandates like those in some US states. Still, doubts remain about the potential for cost reductions. The uncertainties include recent inflation in the cost of battery materials and questions about the pace of the rollout of "giga-factories" for grid-scale batteries.

**The rise of an integrated European power market with Germany at its core**

We expect a more integrated European power market including significant coupling of power hubs. With cross-border flows of about 200 TWh a year in 2030, Germany is expected to be at the center of the European power system. The country, now a net power exporter, is expected to become a net power importer by the mid 2020s. Interconnection capacity could grow about 50 percent by 2030 (Exhibits 4 and 5), and this should further reinforce Germany's position as Europe's most liquid power market. The country represents a key strategic region for European utilities and traders aiming to manage market risks in their power portfolios.

## Implications for the European power system

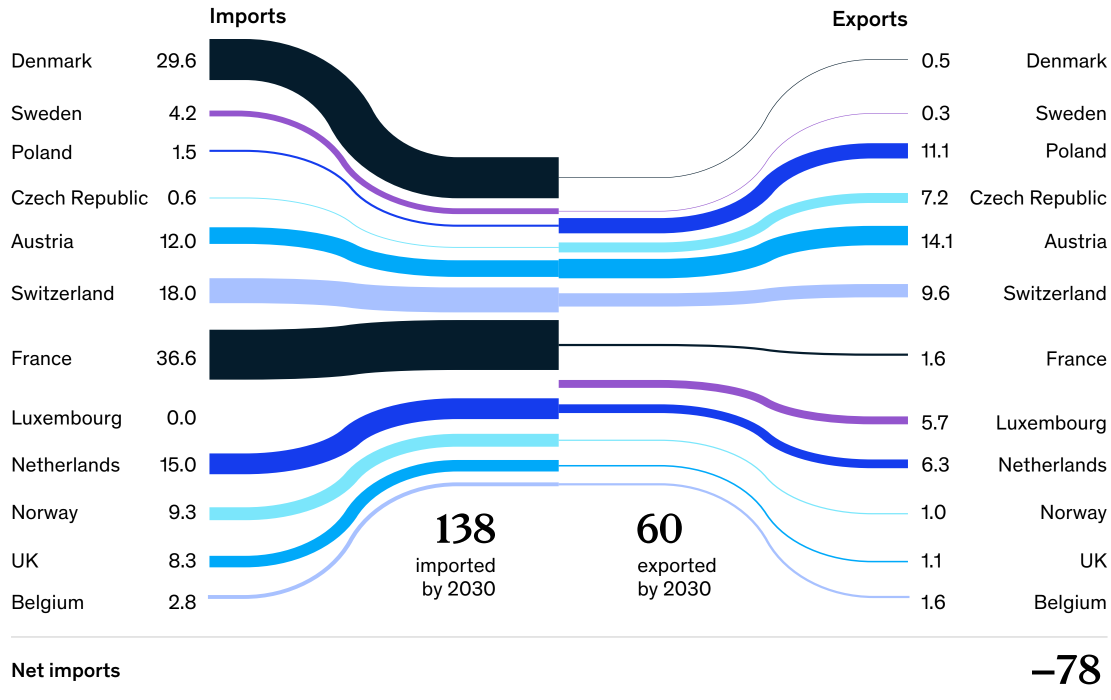
Fundamental trends in the European power system are expected to lead to a much more volatile power-pricing environment, as we already see from this year's power-price surge. Europe is entering a period of extreme volatility, with daily and hourly prices hitting new highs. In Germany, upward of 3,000 hours a year may be priced at more than €100 or at less than €10 by 2030, compared with just several hundred hours today, according to McKinsey's EU Power Model. This volatility could spur new behavior from market participants—for

**To ensure the grid's stability, the power sector must compensate for the drop in dispatchable assets.**

Exhibit 4

## Germany is expected to increasingly rely on imports.

**Power import and export to and from Germany in 2030,**[1] terawatt-hours

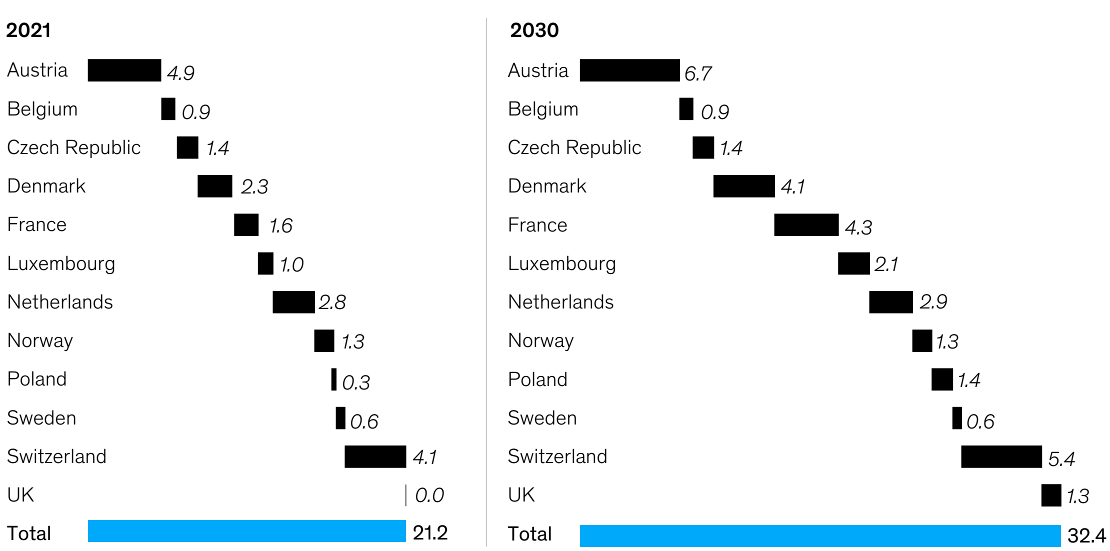



[1]Scenario: accelerated energy transition including hydrogen demand. Contingent to availability of dispatchable power from neighboring countries.
Source: McKinsey Power Solutions, EU power model, June 2021

Exhibit 5

## Germany's expanding interconnections will put the country at the heart of the European power system.

**Germany's interconnection outlook,**[1] gigawatts




[1]Average of import and export of net transfer capacity at 90% availability, including both new construction and increase of tradeable capacity.
Source: Bundesnetzagentur; *TYNDP 2020: Main report*, ENTSO-E, November 2020, tyndp.entsoe.eu; McKinsey Power Solutions, EU power model, June 2021

example, the level at which they bid for their electricity supplies or hedge their future needs.

One way for players to better understand the power market's dynamics, including volatility, is the merit-order cost curve, which illustrates the price-setting mechanism in the power market. Five elements are particularly important to anticipate future movement in power prices and price volatility (Exhibit 6):

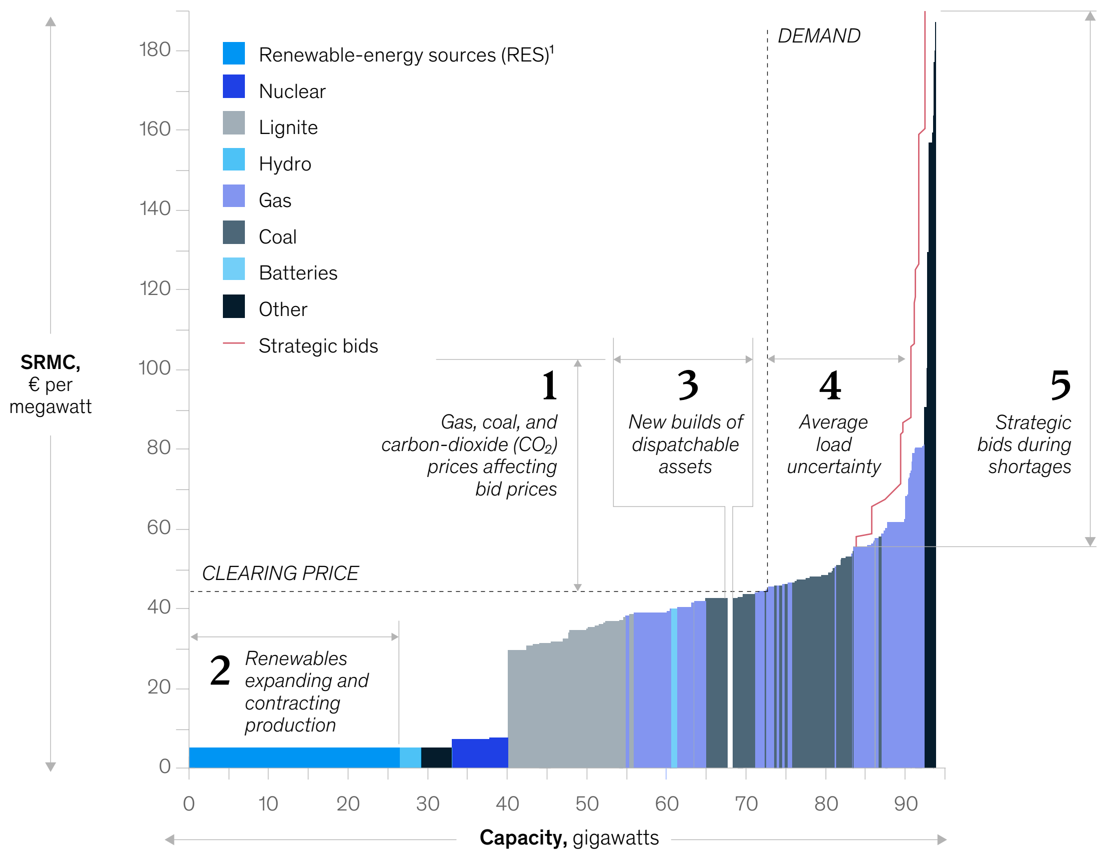
— *Gas, coal, and $CO_2$ prices altering the marginal production costs of thermal power plants.* The rise or fall of gas, coal, and $CO_2$ prices will drive the volatility of the market's clearing price.

— *The intermittency of renewables.* The volume of renewables power output will push the curve either to the left or to the right, potentially leading to very low or very high clearing prices.

Exhibit 6

## The merit-order cost curve exemplifies the pricing mechanism in the European power market.

**Short-run marginal cost (SRMC) for Germany, 2021, illustrative**




**1 Gas, coal, $CO_2$ prices affecting clearing price**
Rise or decline in gas, coal, and $CO_2$ prices that will set the clearing price of the market

**2 RES intermittency**
Very low power prices when RES are pricing technology. High variability of RES power generation means available capacity fluctuates dramatically

**3 New builds of dispatchable assets**
Uncertainty on economic signals required to stimulate sufficient new builds of dispatchable assets, creating potential shortages

**4 Average load uncertainty**
Significant volatility in load demand driven by strong electrification (electric-vehicle charging, industry electrification, etc)

**5 Strategic bids during shortages**
Potential for extremely high prices in growing number of hours with system shortage

[1]Renewables placed at €5/megawatt-hour for illustrative purpose.
Source: McKinsey Power Solutions, EU power model, June 2021

— *Dispatchable-asset new builds.* Uncertainty about the volume and cost of dispatchable-asset new builds (for example, batteries and combined-cycle gas turbines) could raise or lower clearing prices.

— *Average load uncertainty.* Volatility in hourly power demand from sources such as electric-vehicle charging and industrial electrification could create supply shortages leading to high clearing prices during certain hours.

— *Strategic bids during shortages.* In a growing number of hours, anticipated supply shortages could lead market players to bid their capacity at prices higher than the marginal cost, theoretically up to the maximum allowed price.

## How can market players respond?

The European power market is entering uncharted territory. When utilities and large power buyers face that kind of uncertainty, strategic risk management becomes a matter of survival. In the United Kingdom, recent defaults of power and gas retailers, following the surge in gas prices, illustrate the high stakes. Here are some steps players can take to address the uncertainties:

— *Investing in best-in-class risk-management models.* These would cover market-price risks along with the nonlinear volume or shape risks of day-ahead and intraday power markets. For example, players could make more use of advanced stochastic profit-at-risk or cash-flow-at-risk models, such as running them in quasi-real time to best inform hedging strategies. Ad-hoc stress tests will also be critical to run on a periodic basis.

— *Pursuing flexibility in portfolios.* To reduce exposure to price surges in wholesale power markets, players could source more flexibility both on the demand and supply sides of portfolios, including, for example, demand-side response aggregation and investments in gas-peaker assets, grid-scale batteries, and virtual power plants (VPP).[3]

— *Developing an active presence in the most liquid European power hubs.* Germany is expected to remain the most liquid market and an ideal place to optimize hedging strategies across Europe—for example, by employing proxy hedges and cross-border hedges in the event of strong market coupling and limited liquidity in other markets.

— *Using power purchase agreements with partial or full fixed-price arrangements.* Companies could use this strategy to hedge long-term power purchases or sales, thus reducing exposures to volatile power prices.

The European power market is entering an unprecedented phase. Market participants that hope to be industry leaders must urgently invest in best-in-class risk and portfolio management.

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[3] VPPs can provide the flexibility of a traditional power plant. They are executed through a financial agreement between parties.