

Electric Power & Natural Gas Practice

European utilities at an inflection point: Four strategic evolutions ahead

European utilities face a period of discontinuity: Electrification, renewables, flexibility needs, AI, and policy shifts are reshaping economics, driving four strategic responses as industry structure is redefined.

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European utilities currently face four fundamental shifts that are structurally transforming their operating environment: the acceleration of electrification and flexibility needs at scale; the rapid rise of a digital and AI-driven economy; an acute focus on sovereignty and affordability; and sustained regulatory intervention. In turn, these forces are shifting where value is created, prompting four distinct strategic responses from utilities.

As the utility paradigm of a decade ago—anchored in merchant and day-ahead markets, developer-led renewables build-out, and continued network unbundling—has broken down, it is being replaced by a market defined by intermittency, decentralization, and a higher share of policy-backed revenues. The future utility will be anchored less by the scale of its physical assets than by the flows it controls. Specifically, its core assets will be its grid access points, system flexibility, load-firming capacity, and its volume of aggregated supply and sales from less than 1 megawatt (MW) or 1 megawatt hour (MWh) to utility-scale assets that it can orchestrate across the grid.

Here, history offers a cautionary tale. When the renewables wave first accelerated, many incumbents were slow to react, allowing agile independent developers to capture early value, erode incumbents' market share, and establish themselves as large-scale independent power producers (IPPs).

Today, the story is more complex. While a similar pattern is unfolding with a new wave of digital and AI-enabled entrants targeting aggregation, retail, and flexibility services, there is also a movement toward more integrated utility models.

In this article, we examine in detail the shifting forces within the European utilities industry that are refocusing where value is created, unpack the strategic responses emerging in the new energy landscape, and then consider the implications for energy companies.

Four shifts are causing a migration of value across the European energy utilities sector

The dissolution of the old utility framework has necessitated a transformation of the operating environment, which has caused four significant changes across the sector. Each comes with its own challenges and needs.

1. Electrification demands more capacity, but the harder challenge is turning raw renewables megawatts into usable power

After years of relatively flat power demand growth, the Continued Momentum scenario in McKinsey's *Global Energy Perspective 2025* projects European power demand to grow from about 3,000 terawatts per hour (TWh) in 2025 to approximately 4,300 TWh in 2040 (Exhibit 1). This increase is primarily driven by the electrification of the transport sector (an increase of about 400 TWh, including about 140 million electric vehicles [EVs] by 2040), buildings (more than 55 million residential heat pumps by 2040), data centers (an increase of about 450 TWh), and industry (about 200 TWh of additional consumption from electrified industrial processes). As a result, electricity's share of final energy consumption is expected to rise to approximately 32 percent by 2040 from about 20 percent today.¹ In parallel, European natural gas

¹ *Global Energy Perspective 2025*, McKinsey, October 13, 2025 (Continued Momentum scenario).

demand is estimated to shrink, on average, by 2 percent a year up to 2030, further highlighting the need for historical gas and power utilities to expand into power value chain activities (Exhibit 2).

Meeting this demand will require a significant acceleration in supply, with renewables (solar, onshore and offshore wind, hydro, and biomass) and nuclear estimated to account for about 95 percent of Europe's power generation by 2040.² Within this, solar and onshore wind are projected to grow at about 7 percent a year up to 2040, and offshore wind at about 11 percent.³

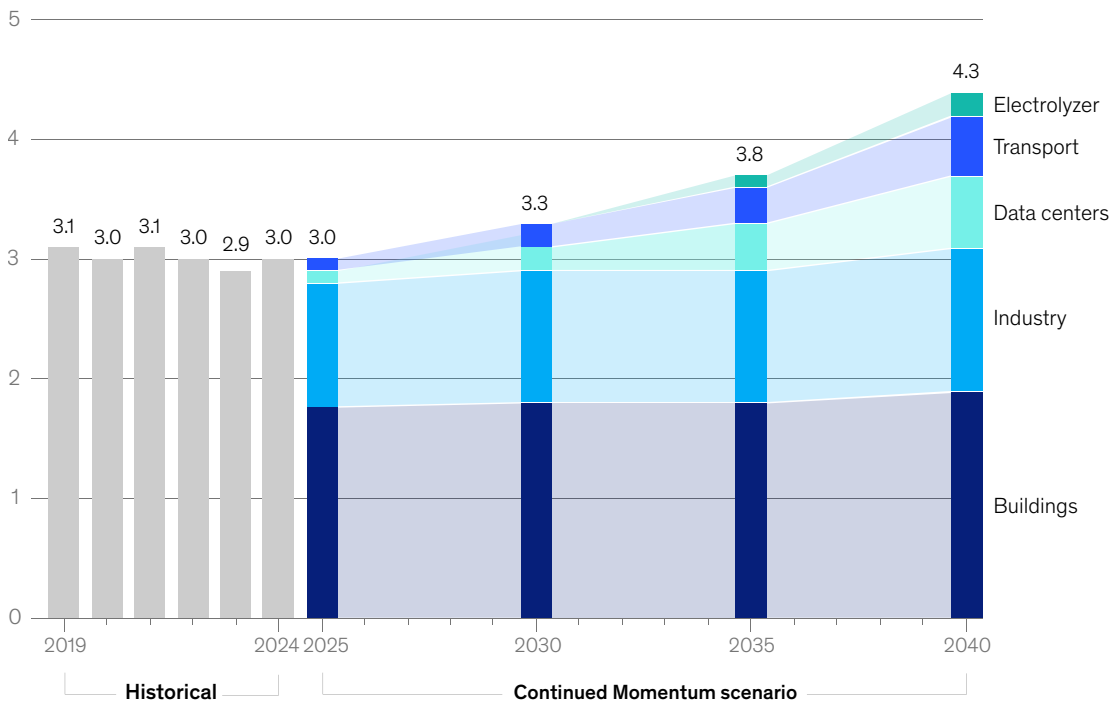
² Share of total power generation from solar, onshore and offshore wind, hydro, biomass, and nuclear in the Continued Momentum scenario in *Global Energy Perspective 2025*, McKinsey, October 13, 2025.

³ Based on installed capacity projections in the Continued Momentum scenario in *Global Energy Perspective 2025*, McKinsey, October 13, 2025.

Exhibit 1

European power demand is projected to shift from decline to robust growth through 2040.

Net electricity consumption,¹ thousand terawatt-hours



¹ EU-27 plus Norway, Switzerland, and the United Kingdom. Excludes transmission and distribution (T&D) load and storage losses.

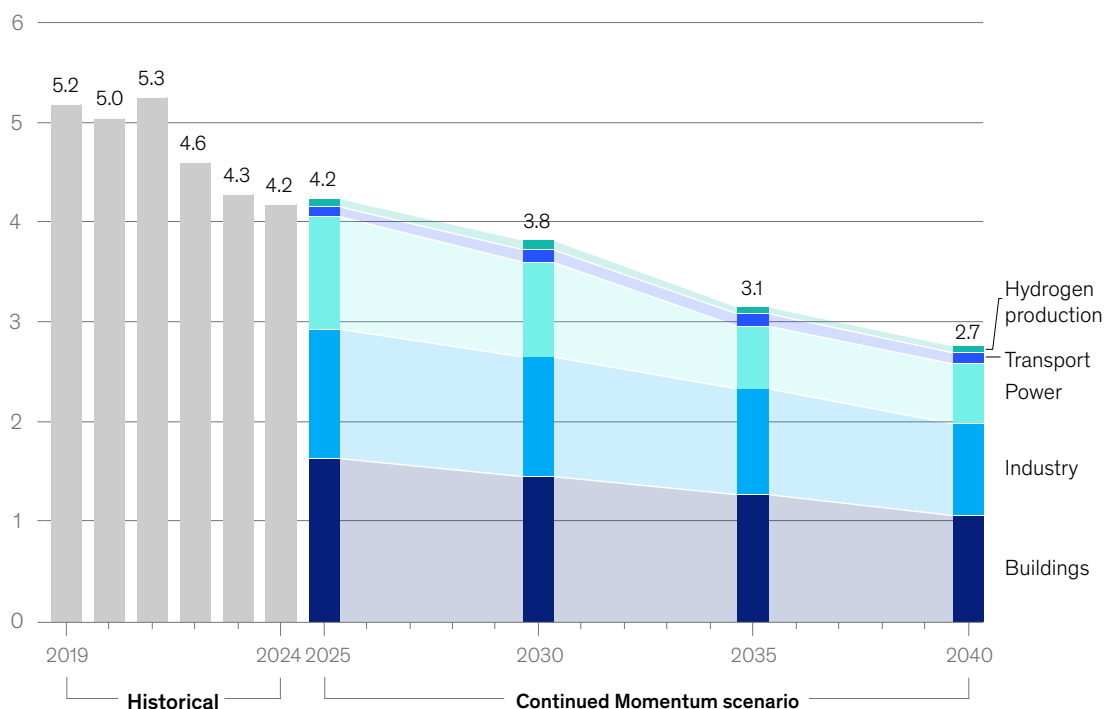
Source: *Global Energy Perspective 2025*, McKinsey, October 13, 2025

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Exhibit 2

European natural gas demand is projected to decline through 2040.

Natural gas demand,¹ thousand terawatt-hours



¹ EU-27 plus Norway, Switzerland, and the United Kingdom. Converted from billion cubic meters to terawatt-hours.
Source: Global Energy Perspective 2025, McKinsey, October 13, 2025

McKinsey & Company

But this new supply is far more decentralized and intermittent than the centralized fleet of the past, making power systems increasingly complex as the number of grid connection points multiplies. There are already 250 million connected households and businesses in European distribution grids.⁴ In France, grid-connected generation assets rose from 61,000 in 2010 to more than one million in 2024,⁵ and in Germany, delivery points for final customers reached 52.9 million in 2024,⁶ up from 51.6 million in 2020.⁷ This is widening the distance between generation and demand and enlarging the temporal mismatches between supply and demand.

The fundamental challenge is shifting from merely expanding generation capacity to delivering more usable, connected, and flexible clean power. Europe does not just need more renewable megawatts; it needs power to be commercially viable and available at the right time and place. The primary bottleneck

⁴ *Distribution grids handbook*, Eurelectric, November 21, 2024.

⁵ Adrien Pécourt, "Avec plus de 1 million de sites de production, le système électrique français change d'échelle" [With more than 1 million production sites, the French electricity system changes scale], *Le Monde*, October 29, 2024.

⁶ *Monitoringbericht 2025* [Monitoring report 2025], Working Group on Energy Monitoring, January 26, 2026.

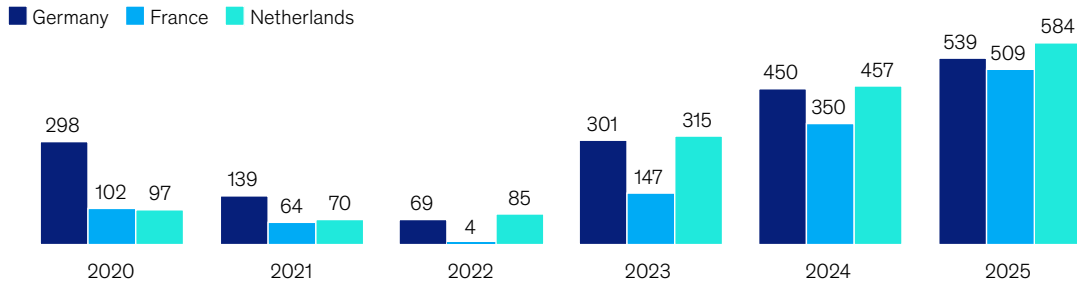
⁷ *Anzahl der Marktlösungen von Letztverbrauchern im deutschen Stromnetz in den Jahren 2014 bis 2024* [Number of metering points of final consumers in the German electricity grid, 2014 to 2024], Statista, November 2024.

here is the system's ability to absorb, move, store, and price electricity. In Europe, this trend is reflected in record volumes of voluntarily curtailed renewable power and increasingly frequent hours of negative pricing (Exhibit 3).

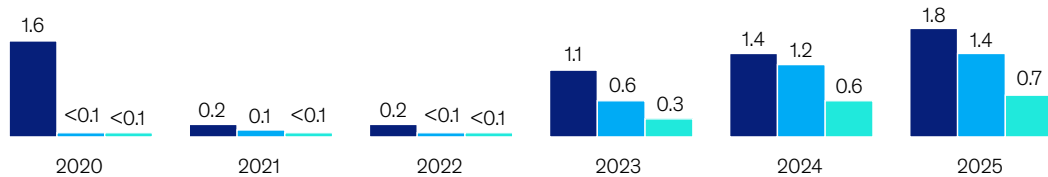
Exhibit 3

In Europe, negative-price hours and related curtailment have risen sharply.

Hours of negative day-ahead price, number



Total commercial curtailment per year, terawatt-hours



Source: European price sensitive curtailment report 2025, Montel

McKinsey & Company

In 2025, curtailment (the intentional reduction or disconnection of generation) reached about 1.8 TWh in Germany, 1.4 TWh in France, and 0.7 TWh in the Netherlands.⁸ This combined total of nearly 4 TWh represents an 18 percent compound annual growth rate since 2020, when curtailment stood at 1.7 TWh. Regional weather patterns frequently cause simultaneous renewable generation peaks across Europe, neutralizing cross-border exports as a relief valve. For instance, peak wind or solar conditions in France and Germany often synchronize with neighboring markets, closing off export options.⁹ Similarly, the highly interconnected Netherlands struggles to export peak solar output when Belgium and Germany are also oversupplied. This regional synchronization limits export demand, depresses day-ahead prices, and directly drives up commercial curtailment (in which an oversupply of renewables during peak production periods pushes market prices to zero or below).

⁸ France, Germany, and the Netherlands see the highest volumes of commercial curtailment, making up over 80 percent of the curtailment volumes across the ten countries monitored (Austria, Belgium, France, Finland, Germany, Hungary, the Netherlands, Poland, Switzerland, and the United Kingdom). *European price sensitive curtailment report 2025*, Montel, 2025.

⁹ *European price sensitive curtailment report 2025*, Montel, 2025.

Europe thus needs greater grid capacity, storage, and flexibility to make clean power usable where and when it is needed. The build-out of intermittent renewables creates grid congestion and temporal mismatches between when power is generated and when it is needed. This, in turn, leads to curtailment and price cannibalization, resulting in a rising premium on solutions that can resolve these bottlenecks—flexibility, storage, demand response, and priority grid access. Maintaining grid stability will require substantial investment in enabling infrastructure and flexibility solutions, including battery energy storage systems (BESS), demand-side response (DSR), spatial optimization (for example, displacing the load across a network of assets such as data centers), flexible assets (thermal and hydro), and grid expansion.

Alongside this shift, generation is becoming more fragmented across incumbent utilities, IPPs, and decentralized asset owners, including hybrid consumers or “prosumers.” In Germany, incumbent utilities accounted for approximately 82 percent of installed generation capacity in 2000, IPPs for about 15 percent, and prosumers for 3 percent (Exhibit 4).¹⁰ Since then, the ownership structure has diversified significantly: As of year-to-date 2026, utilities account for about 26 percent of installed capacity, IPPs for about 41 percent, and prosumers for about 33 percent. Reflecting the rapid expansion of distributed residential and industrial self-generation by prosumers, the average size of new installations has fallen from more than 50 MW in the 1970s and 1980s to about 400 kW in 2000 and about 30 kW today. The average size of total installations (stock capacity) has decreased from approximately 1,800 kW in 2000 to about 50 kW today.¹¹ Traditional utilities are increasingly retreating from direct investment in generation capacity.

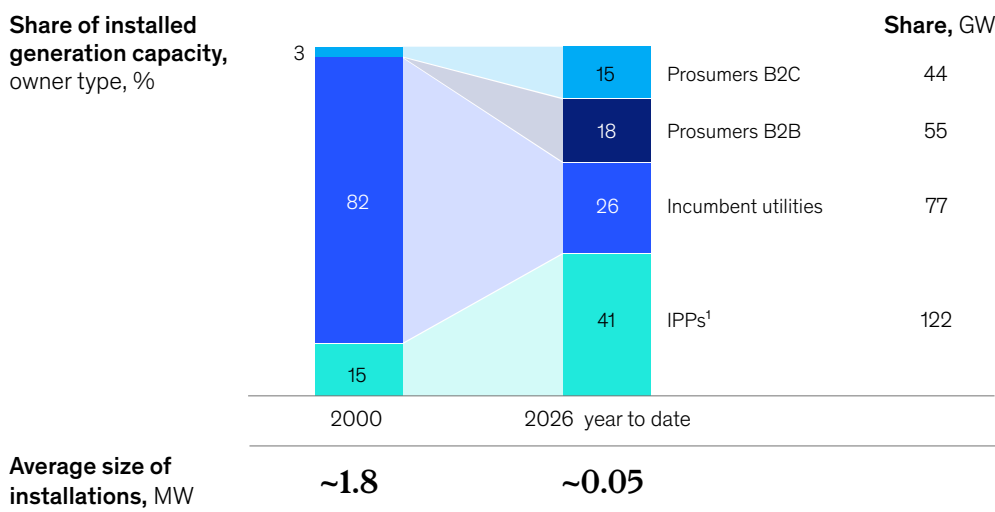
This partly reflects a changing market. While the early 2000s were defined by liberalization, generation investment today has become more fragmented, competitive, and policy-dependent, with returns shaped by auctions, support schemes, grid constraints, and wholesale price volatility. By contrast, regulated grid infrastructure offers more predictable economics, giving incumbents an incentive to deploy capital into networks rather than compete in an increasingly complex generation market. If incumbents prioritize vertical integration and network acquisition over direct investment in generation, the resulting capacity gap is likely to be filled by new entrants and other nontraditional actors, potentially including large offtakers, such as data centers, seeking dedicated generation to secure firm supply.

¹⁰ Owner-type shares and average installation size are based on historical data for Germany. Cumulative installed capacity as of year-end 2000 and year-to-date 2026; all in-operation electricity generation units across photovoltaic (PV), wind, hydropower, biomass, combustion, nuclear, and geothermal (battery and other storage excluded). Each asset is assigned to one of four owner types using: (i) a curated utility or independent power producer (IPP) mapping covering about 400 named operators, applied regardless of asset size and snapshot year; (ii) name-based overrides—LEAG, RWE, STEAG, Uniper (including Datteln 4), and Vattenfall—always classifying these operators and their subsidiaries as incumbent utilities; (iii) wind units default to IPPs unless the operator name signals a utility (utility group or municipal utility keyword), regardless of operator type; (iv) nonwind assets are then classified as follows: operators flagged as natural persons (Marktakteur Personenart = 518) with asset capacity of 5 MW or less are B2C prosumers, and all other nonwind operators are classified using the same keyword rules at all sizes (utility group and municipal utility keywords mark incumbent utilities; renewable project company keywords mark IPPs); and (v) the residual defaults to B2B prosumer (for example, large industrial players) at 5 MW or less, and to a large-scale unresolved bucket above 5 MW that is allocated pro rata between utilities and IPPs based on those already classified as more than a 5 MW mix in the same snapshot year. Rule-based proxy, not a legal ownership audit. Marktstammdatenregister, “Gesamtdatenexport” [Core Energy Market Data Register, “Complete data export”], Bundesnetzagentur, accessed May 28, 2026; McKinsey analysis.

¹¹ Marktstammdatenregister, “Gesamtdatenexport” [Core Energy Market Data Register, “Complete data export”], Bundesnetzagentur, accessed May 28, 2026; McKinsey analysis.

Exhibit 4

In Germany, generation ownership has shifted from incumbents to independent power producers and prosumers.



Note: Owner-type shares and average installation size are based on historical data for Germany. Cumulative installed capacity as of end-of-year 2000 and year-to-date 2026; all in-operation electricity generation units across photovoltaic (PV), wind, hydropower, biomass, combustion, nuclear, and geothermal (battery and other storage excluded). Each asset is assigned to one of four owner types using (i) a curated utility or independent power producer (IPP) mapping covering about 400 named operators, applied regardless of asset size and snapshot year; (ii) name-based overrides—LEAG, RWE, STEAG, Uniper (including Datteln 4), and Vattenfall—always classifying these operators and their subsidiaries as incumbent utilities; (iii) wind units default to IPPs unless the operator name signals a utility (utility group or municipal utility keyword), regardless of operator type; (iv) nonwind assets are then classified as follows: operators flagged as natural persons (*Marktakteur Personenart* = 518) with asset capacity of 5 MW or less are B2C prosumers, and all other nonwind operators are classified using the same keyword rules at all sizes (utility group and municipal utility keywords mark incumbent utilities; renewable project-company keywords mark IPPs); and (v) the residual defaults to B2B prosumer (for example, large industrial players) at 5 MW or less, and to a large-scale unresolved bucket above 5 MW that is allocated pro rata between utilities and IPPs based on those already classified as more than a 5 MW mix in the same snapshot year. Rule-based proxy, not a legal ownership audit.

¹Independent power producers.

Source: Marktstammdatenregister, "Gesamtdatenexport" [Core Energy Market Data Register, "Complete data export"], Bundesnetzagentur, accessed May 28, 2026; McKinsey analysis

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2. AI adoption is accelerating data center build-out and creating new demands and flexibility value pools

Data centers are expanding rapidly across the world, becoming a defining global trend. Europe's data center capacity is expected to roughly double from about 20 GW of IT capacity¹² in 2025 to almost 40 GW by 2030, providing the computational backbone for an increasingly digital, AI-driven economy.¹³

This growth is spurring new products and services tailored to data center operators' needs. Utilities and other energy providers are expanding four offerings in particular:

- **orchestrated flexibility** (spatial, network, and temporal) built on AI workload management, with leading operators already demonstrating a 5 to 10 percent temporary peak load reduction¹⁴

¹² Refers to total uninterruptible power supply (UPS) power—power consumed exclusively by the servers, including network.

¹³ Camilla Naschert and Susan Dlin, "European data center power demand to double by 2030, straining grids," S&P Global, July 30, 2025, S&P Global Energy ©2026 by S&P Global Inc.; *Global Energy Perspective 2025*, McKinsey, October 13, 2025 (Continued Momentum scenario).

¹⁴ Tyler Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell, *Rethinking load growth: Assessing the potential for integration of large flexible loads in US power systems*, Nicholas Institute for Energy, Environment & Sustainability, Duke University, 2025.

- **on-site storage** that extends the legacy uninterruptible power supply (UPS) model. For example, Aligned Data Centers and Calibrant Energy jointly deployed a 31 MW/62 MWh battery energy storage system (BESS) to speed up interconnection and secure power ahead of traditional grid upgrades¹⁵
- **bridge and backup power** for data centers connected ahead of schedule. For example, Google has integrated about 1 GW of flexible demand capacity across its data center fleet, enabling utilities to accelerate grid access and unlock capacity in power-constrained locations¹⁶
- **microgrid services** for data centers that operate independently of the grid and round-the-clock clean power solutions seen in previous years

Demand for gas turbines and backup generation systems such as gas engines, transformers, and related infrastructure has increased sharply, with turbine order books extending beyond 2029. Siemens Energy reported in August 2025 that about 60 percent of its 14 GW of gas-turbine year-to-date orders were linked to data center projects,¹⁷ underscoring the growing competition for critical equipment across the energy sector and the need for utilities to reshape their supply chain strategies.

3. Sovereignty and affordability concerns are driving regionalization across generation, supply chains, critical materials, and grids

Efforts to diversify energy supply have accelerated since the 2021–22 energy crisis when Europe's vulnerability was starkly exposed, because it imported 63 percent of the total energy it consumed.¹⁸ Since then, although the European Union's overall energy import dependency has stabilized, it remains structurally high at 57 percent as of 2024, with net imports still covering nearly 60 percent of the European Union's total energy needs.¹⁹ In 2023, the European Union raised its binding renewable energy sources (RES) target to at least 42.5 percent of final energy consumption by 2030 from 32 percent; set a target of 60 GW of installed offshore wind capacity by 2030; and established an electricity interconnection target of 15 percent for all member states.²⁰

These measures aim to reduce dependence on imported fuels, such as natural gas, and to improve system resilience with a broader, more geographically diversified pool of generation resources. But intended measures are increasingly clashing with market realities, as a combination of surging capital costs, supply chain bottlenecks, and unfavorable auction designs has cooled developer appetite. This friction shows in recent bidding rounds. Germany's August 2025 offshore auction for 2.5 GW of capacity across its N-10.1 and N-10.2 North Sea sites closed without a single bid;²¹ a failure echoed in the Netherlands' late-2025 auction for the 1-GW Nederwiek I-A site.²²

As project economics deteriorate and expected returns no longer justify the development risks, even well-capitalized oil majors and traditional developers are scaling back their offshore wind plans. The challenge is particularly acute in Germany, where the nuclear phase-out has removed domestic carbon-free capacity

¹⁵ "Aligned and Calibrant to deploy first-of-its-kind on-site battery storage project to unlock utility power for data centers," Aligned press release, October 22, 2025.

¹⁶ Google Blog, "A new milestone for smart, affordable electricity growth," blog entry by Michael Terrell, March 19, 2026.

¹⁷ Rachel Millard, "Siemens Energy orders hit record on 'enormous' data centre demand," *Financial Times*, August 6, 2025.

¹⁸ *Shedding light on energy in Europe—2024 edition*, Eurostat, March 2024.

¹⁹ *Energy in Europe—2026 edition: Import dependency*, Eurostat, March 2026.

²⁰ Under the 2024 revised goals, member states updated their nonbinding regional targets under the trans-European networks for energy (TEN-E) regulation, setting cumulative regional offshore renewable targets of 86–89 gigawatts (GW) by 2030 and 355–366 GW by 2050. "Boosting offshore renewable energy for a climate neutral Europe," European Commission press release, November 19, 2020; *Offshore renewable energy*, European Commission, 2024; "Regulation (EU) 2018/1999 on the governance of the Energy Union and Climate Action," EUR-Lex, European Union, December 11, 2018.

²¹ "Germany's 2.5 GW offshore wind auction fails to attract bidders," Enerdata, August 7, 2025.

²² "Europe's offshore wind auctions come under fire," IIR Energy powered by Industrial Info Resources, December 2, 2025.

from the system, increasing the burden on renewables, grids, flexibility, and imported fuels to maintain security of supply. The European Union's energy targets may not be met without significant regulatory and financial restructuring.

Energy sovereignty efforts are also extending to the heating and cooling sector, which accounts for nearly half of the European Union's energy consumption and remains about 70 percent reliant on fossil fuels, mostly natural gas.²³ Under the 2025 Affordable Energy Action Plan and Clean Industrial Deal, the European Commission announced a new Heating and Cooling Strategy for 2026, intended to support more integrated local heat planning, including district heating modernization, industrial waste heat recovery, geothermal energy, and other renewable heat sources. These local heat networks can become circular energy systems by integrating waste-to-energy, biomass cogeneration, residual industrial heat, and thermal storage—turning local waste streams and byproducts into dispatchable heat and power. These efforts collectively strengthen energy sovereignty.

At the same time, concerns over strategic dependencies on non-European supply chains are prompting a shift toward greater supply chain resilience and diversification. This is reflected in European Union industrial policies, such as the Net-Zero Industry Act (NZIA), which targets domestic manufacturing capacity equivalent to 40 percent of annual deployment needs for clean technologies by 2030.²⁴ The Critical Raw Materials Act (CRMA) seeks to reduce import dependence by requiring 10 percent domestic extraction, 40 percent domestic processing, and 25 percent strategic raw materials recycling by 2030, while limiting reliance on any single non-European Union country to 65 percent of supply.²⁵ In the first half of 2026, the European Union has also increased scrutiny of Chinese participation in critical energy infrastructure—including restricting European Union funding for renewable energy projects that use inverters from high-risk suppliers—reflecting a broader shift from cost optimization toward supply chain resilience and strategic autonomy.

4. More proactive regulatory action is causing the pure merchant era to end and capping both upside and downside

In response to these new market dynamics, European policymakers are increasingly relying on long-term support mechanisms to encourage investment in capital-intensive energy infrastructure, while limiting exposure to power price volatility. This shift was formalized in the EU Electricity Market Design Reform of 2024, which established two-way contracts for difference (CfDs) as the default form of direct price support for new, publicly supported renewable and nuclear projects.²⁶ The approach is widely used in offshore wind. For example, in March 2026, the European Commission approved a €5 billion Danish state aid scheme built on a 20-year, two-way CfD structure to support about 1.8 GW of offshore wind capacity.²⁷ Similar frameworks underpin offshore wind deployment in France, Poland, the Netherlands, and the United Kingdom.

²³ "Heating and cooling from renewables gradually increasing," Eurostat, February 3, 2023; "Heating and cooling," European Commission, 2026 (based on Eurostat 2024 data).

²⁴ "Regulation (EU) 2024/1735 of the European Parliament and of the Council of 13 June 2024 establishing a framework of measures for strengthening Europe's net-zero technology product manufacturing ecosystem," EUR-Lex, European Union, June 13, 2024 (Net-Zero Industry Act).

²⁵ "Regulation (EU) 2024/1252 of the European Parliament and of the Council of 11 April 2024 establishing a framework for ensuring a secure and sustainable supply of critical raw materials," EUR-Lex, European Union, April 11, 2024 (Critical Raw Materials Act).

²⁶ "Regulation (EU) 2024/1747, Article 19b, of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/943 and (EU) 2019/942 as regards improving the Union's electricity market design," EUR-Lex, European Union, June 26, 2024.

²⁷ "Commission approves €5 billion Danish state aid scheme to support offshore wind energy," European Commission press release (IP/26/655), March 23, 2026.

At the same time, governments are introducing complementary mechanisms to support system adequacy and flexibility, providing incentives for local dispatchable generation to reduce exposure to external dependencies such as fuels and equipment. Market-wide mechanisms are already established in countries that include Belgium, France, Italy, Ireland, Poland, and the United Kingdom. Although regulated support accounted for approximately 21 percent of the electricity market in 2023 (up from about 16 percent in 2014),²⁸ member states are now rapidly accelerating capacity reforms.

Germany, for example, under its updated power plant strategy plans to procure roughly 12 GW of new dispatchable and flexible capacity by 2031.²⁹ These competitive auctions are set to be tendered over the next two to three years—two 4.5 GW tranches are scheduled for September and December 2026, followed by a 2 GW tender planned for 2027.³⁰ In addition, Greece and Spain are advancing their own capacity market designs. Collectively, such capacity mechanisms aim to improve investment visibility while supporting the deployment of low-carbon generation such as offshore wind, storage such as batteries, and other flexibility resources such as gas turbines needed to maintain system reliability.

In parallel, governments are taking direct stakes in critical energy infrastructure. In April 2026, the Belgian government entered exclusive negotiations with Engie regarding the potential acquisition of the country's nuclear fleet.³¹ This follows France's full nationalization of Électricité de France (EDF) in 2023 to support nuclear investment and the energy transition.³² These actions reflect a broader shift toward a more active role for governments in sectors where large capital requirements, long asset lives, and security of supply considerations challenge the purely market-based investment models introduced in the early 2000s. Disruptions in the Strait of Hormuz in 2026 have reinforced the trend, underscoring how exposure to global energy chokepoints can rapidly translate into supply and price risks, raising the strategic value of domestic, diversified, and controllable energy supply.

As a result, a growing share of investment in the European energy sector is flowing toward assets with greater revenue and cash flow visibility and more stable, infrastructure-like returns. Regulatory and policy frameworks are becoming increasingly important determinants of profitability, reducing reliance on pure merchant exposure and wholesale market volatility. This trend extends beyond planned market design reforms. During the 2021–22 energy crisis, Portugal and Spain initially capped gas prices for power generation at €40 per MWh, rising to €70 per MWh over 12 months,³³ and the European Union imposed a temporary €180 per MWh revenue cap on inframarginal generators.³⁴ These measures demonstrated the increasingly active role of policymakers in shaping energy markets when security, affordability, or economic competitiveness are at stake.

In this environment, evolving regulatory and market frameworks are becoming progressively important determinants of investment decisions and profitability. Utilities will need to anticipate these developments and incorporate them into capital allocation, portfolio strategy, and investment planning.

²⁸ The 2023 figure is electricity receiving renewable energy sources (RES) support as a share of gross electricity produced. Countries included Austria, the Czech Republic, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, Malta, North Macedonia, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom. The share of supported RES electricity is not an indicator of the overall share of RES electricity. *Status review of renewable support schemes in Europe for 2022 and 2023*, Council of European Energy Regulators (CEER), Table 6, July 15, 2025.

²⁹ *Agreement with European Commission on key aspects of the power plant strategy*, German Federal Ministry for Economic Affairs and Climate Action, January 27, 2026.

³⁰ "German govt starts work on power plant strategy law," *Renewables Now*, April 22, 2026.

³¹ "The Belgian state and Engie Group enter into exclusive negotiations for the acquisition by Belgium of Engie's nuclear activities," Engie press release, April 30, 2026.

³² "EDF quits Paris stock exchange after full nationalization," *Reuters*, June 8, 2023.

³³ "State aid: Commission approves Spanish and Portuguese measure to lower electricity prices amid energy crisis," *European Commission press release* (IP/22/3550), June 8, 2022.

³⁴ "Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices," *EUR-Lex*, European Union, October 7, 2022.

These four fundamental shifts play out in different combinations by country, shaped by structural starting points—nuclear share, offshore wind pace, grid congestion, industrial demand, storage needs, and affordability politics. Three market archetypes provide examples:

- **nuclear-anchored sovereign markets**, such as Czechia, France, and Hungary, where nuclear remains the central organizing principle of the system. For example, in France, nuclear supplies about 68 percent of electricity generation,³⁵ with six reactors under construction through the EPR2 program,³⁶ notably to meet a step-up in demand from data centers, hydrogen electrolysis, and industrial electrification (about 30 GW of transmission access rights granted to these new uses by late 2025).³⁷
- **renewables-led industrial economies** in markets such as Belgium and Germany, which carry heavy industrial decarbonization loads on grids built around renewables, with limited or phased-out nuclear. For instance, following the April 2023 nuclear phase-out in Germany,³⁸ the system now contends with severe transmission bottlenecks driving multibillion-euro annual redispatch cost³⁹ and a heavy industrial electricity load (about 41 percent of national electricity).⁴⁰
- **gas-dependent transitioning markets**, such as Greece and Italy, where gas remains the dominant balancing fuel and flexibility is the binding constraint. In Italy, nuclear was retired by 1990 following the 1987 referendum, gas still accounts for about 44 percent of electricity generation, and the renewables-rich South struggles to serve industrial demand concentrated in the North.⁴¹

Four strategic responses are emerging

The four fundamental shifts in the industry are increasing the value of flexibility, enabling new digital and AI-driven capabilities, elevating the importance of energy security and affordability, and reinforcing the role of regulation in shaping industry economics. To navigate these shifts, utilities could pursue four strategic responses (Exhibit 5):

- strengthening integration across the value chain to improve resilience and earnings visibility
- orchestrating distributed energy resources to capture flexibility value, using AI-native platforms to lower cost-to-serve
- developing site and energy infrastructure (“power shell”) and token solutions to capture value at the interface of AI and energy
- securing the next generation of supply technologies

³⁵ *Bilan électricité 2025* [Electricity review 2025], RTE (Réseau de Transport d'Électricité), April 2026.

³⁶ “EDF signs new contracts with partners for the EPR2 programme,” EDF press release, November 5, 2025.

³⁷ *Bilan électricité 2025* [Electricity review 2025], RTE (Réseau de Transport d'Électricité), April 2026.

³⁸ “Deutschland beendet das Zeitalter der Atomkraft” [Germany ends the nuclear age], Bundesministerium für Umwelt (BMUV) press release, April 15, 2023.

³⁹ “SMARD electricity and gas market data platform 2015–25,” Bundesnetzagentur, accessed June 23.

⁴⁰ “Net electricity consumption industry: 190 billion kWh of total 466 billion kWh,” *Energieversorgung 2025 – Jahresbericht* [Energy supply 2025—annual report], German Association of Energy and Water Industries (BDEW), December 17, 2025.

⁴¹ “Italy electricity,” IEA, 2024; *Annual report on the state of services and activities carried out in 2024*, ARERA (Autorità di Regolazione per Energia Reti e Ambiente), August 2025.

Depending on utilities' asset base, capabilities, and market position, they can pursue one or more of these four strategic responses. Since these responses are not mutually exclusive, we anticipate that, in practice, most utilities will adopt a hybrid approach. They can combine elements of multiple responses to tailor a strategy to their operational context and growth objectives.

Exhibit 5

Four strategic responses are emerging in response to an increasingly digital, distributed, and technology-driven energy system.



Integrated utility 2.0 play

Recombine generation, trading and downstream commercialization to optimize merchant risk exposures

Further improve portfolio resilience and secure lower cost of capital through grid reentry (transmission, distribution)



AI-orchestrator play

Aggregate distributed generation assets across small-scale generation assets, prosumers, B2B customers, and municipalities

Leverage AI-native downstream platforms that enable radically lower cost-to-serve and automation of demand-side management



Token-merchant play

Offer energy-as-a-service for data center on-site power optimization and develop "power-shell" solution to enter co-location joint ventures

Orchestrate IT workload flexibility to move up the value chain, shifting from selling power to trading computational capacity and AI tokens



Tech-scaling enabler play

Enable next-gen technologies (eg, SMRs,¹ deep geothermal, thermal energy storage, hydrogen) to reach deployable scale

Partner with OEMs,² EPCs,³ and governments to derisk projects and scale firm, sovereign, and flexible power

Structure developer teams to accelerate deployment

¹Small modular reactors.

²Original equipment manufacturers.

³Engineering, procurement, and construction.

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1. Integrated utilities could reemerge as a response to volatility and capital intensity

The return to integrated utilities, driven by market volatility and high capital intensity, marks a revival of an industry structure that dominated two decades ago. According to McKinsey analysis, the standard paradigm 20 years ago was vertical integration, in which a single entity controlled power generation, network operations, and customer retail. But market deregulation and unbundling fundamentally reshaped the industry toward specialization. Since then, utilities have operated within highly focused core business models—specialized generation retailers (gen tailers), pure play retailers, and dedicated infrastructure operators (mostly around networks).

Today, that era of strict specialization is reverting to integrated models to better manage risk. High wholesale price volatility—such as the 2021–22 European energy crisis—can leave unbundled retail providers acutely exposed, because they lack generation assets to hedge against price spikes. The scale of that exposure became clear during the crisis. In the United Kingdom, 29 energy suppliers exited the market between July 2021 and May 2022, affecting nearly four million households.⁴² In the Netherlands,

⁴² *Seventy-fourth report of session 2022–23*, UK Parliament, November 1, 2023.

by the end of 2021, the Authority for Consumers and Markets (ACM) had revoked the supply licenses of eight energy suppliers—six had gone bankrupt, five of them because of high energy prices.⁴³ In the Czech Republic, 900,000 customers of the Bohemia Energy group's companies lost their supply virtually overnight.⁴⁴

Meanwhile, the high capital intensity of building new generation and storage assets, often without secured income, is forcing IPPs to prioritize secured revenues, strong balance sheets, and low-cost financing. Compounding this challenge is an increasingly selective market for long-term power purchase agreements (PPAs) and battery tolling contracts.

Thus, integration is reemerging in two distinct forms rather than as a single uniform model. The first is forward integration by generators and IPPs into energy management, trading, PPAs, and retail. This is primarily a commercial hedge: It helps to reduce merchant exposure, secure offtake for generation assets, optimize short-term dispatch, capture flexibility value, and improve cash flow visibility. McKinsey analysis indicates that integrated energy management can raise return on invested capital (ROIC) by about two percentage points relative to peers, with value coming from improved risk-return optimization, the ability to adjust energy use or supply over a time period, higher-value product structuring, internal flow consolidation, lower collateral and guarantee costs, and more efficient trading operations (Exhibit 6).

One of the operational implications is that operations and maintenance (O&M) becomes the physical enabler of energy management value. This is particularly visible for IPPs integrating into trading, PPAs, dispatch optimization, and flexibility markets. The O&M mandate shifts from maximizing technical availability at the lowest cost to maximizing value-weighted availability—ensuring assets are available, flexible, and high-performing when and where their output is most valuable. This requires closer coordination among trading, asset management, and field operations so that maintenance windows, performance interventions, and operational constraints are optimized against market value.

The second, more comprehensive form of integration is broader portfolio integration by the largest utilities, extending into regulated transmission and distribution (T&D) assets. For example, predictable earnings from regulated T&D activities help offset the volatility of generation revenues, improving access to capital, strengthening balance sheet resilience, and reducing the weighted average cost of capital (WACC) relative to pure-play companies. Integrated utilities benefit from a lower cost of capital, securing debt at rates that average one percentage point or lower than those of pure play generation companies.⁴⁵ They also exhibit less variation in financing costs across peers, with spreads of roughly one percentage point among integrated utilities compared with about three percentage points for IPPs.

Several large European utilities are pursuing this broader portfolio integration, notably increasing their exposure to regulated T&D assets (Exhibit 7). An example is Engie's €12 billion acquisition of UK Power Networks in 2026,⁴⁶ while peers such as Enel and Iberdrola continue to prioritize their long-standing regulated networks as a core element of their investment cases.⁴⁷

⁴³ 2021 ACM annual report, Netherlands Authority for Consumers and Markets, March 2022.

⁴⁴ Combined publications report on the activities and finances of the Energy Regulatory Office & national report of the Energy Regulatory Office on the electricity and gas industries in the Czech Republic for 2021, Energy Regulatory Office of the Czech Republic, September 12, 2022.

⁴⁵ Utility companies analyzed: BKW, Centrica, EDF, EDP, Elia Group, E.ON, Enel, Engie, ESB, Fortum, Hera, Iberdrola, National Grid, Redea, SSE, and Vattenfall. IPPs analyzed: 7C Solarparken, ABO Energy, Alerion, Alight, Arise, BayWa r.e., Clearvise, ContourGlobal, EDP, Energiekontor, Encavis, Enlight, Grenergy, ERG, Neoen, PNE, Ren Energy, Solaria, and Valtia. McKinsey Value Intelligence Platform.

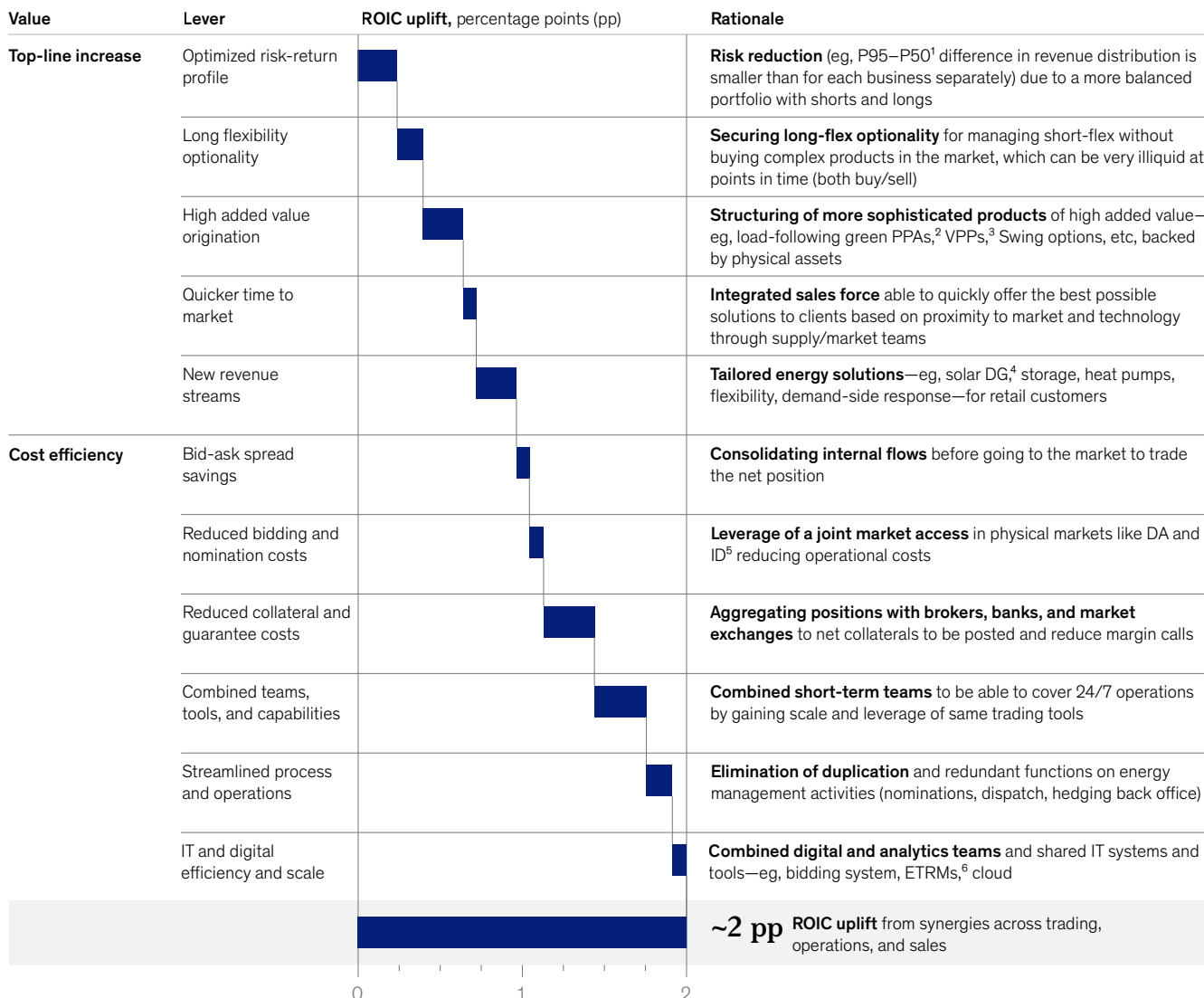
⁴⁶ "Engie announces the acquisition of UK Power Networks, UK's best-in-class electricity distribution network," Engie press release, February 25, 2026.

⁴⁷ "Strategic plan 2025–2028," Iberdrola, accessed July 1, 2026; "Enel's 2025–2027 strategic plan: Executive summary," Enel, accessed July 1, 2026.

Exhibit 6

Integrated generation and retail can improve risk return and cost efficiency, unlocking a ROIC uplift of about 2 percentage points.

Potential ROIC gain across value and cost efficiency



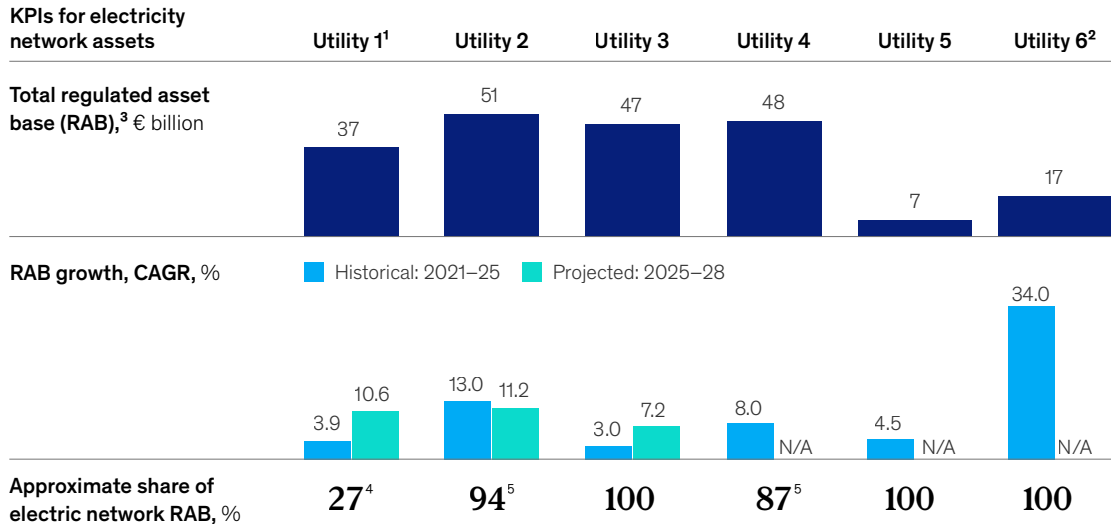
¹95th–50th percentile revenue difference. ²Power purchase agreements. ³Virtual power plants. ⁴Solar distributed generation. ⁵Day ahead and interday. ⁶Energy trading and risk management systems.

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Exhibit 7

Selected European utilities have allocated substantial capital to regulated network assets in 2025.

European utilities' allocated investments



¹ Due to change in RAB scope reporting, CAGR is computed for 2021–24 period.

² Post-acquisition of an entity, 2026.

³ Total networks' RAB (electricity and gas).

⁴ Post-acquisition of an entity (mid-2026), RAB is estimated to increase by ~€10.8 billion.

⁵ Electric network RAB share as reported in FY2024 report; data not reported in FY2025 report.

Source: Company annual reports and investor presentations

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2. Orchestrator utilities could further integrate decentralized assets and unlock new flexibility models while reducing their cost to serve with AI-native platforms

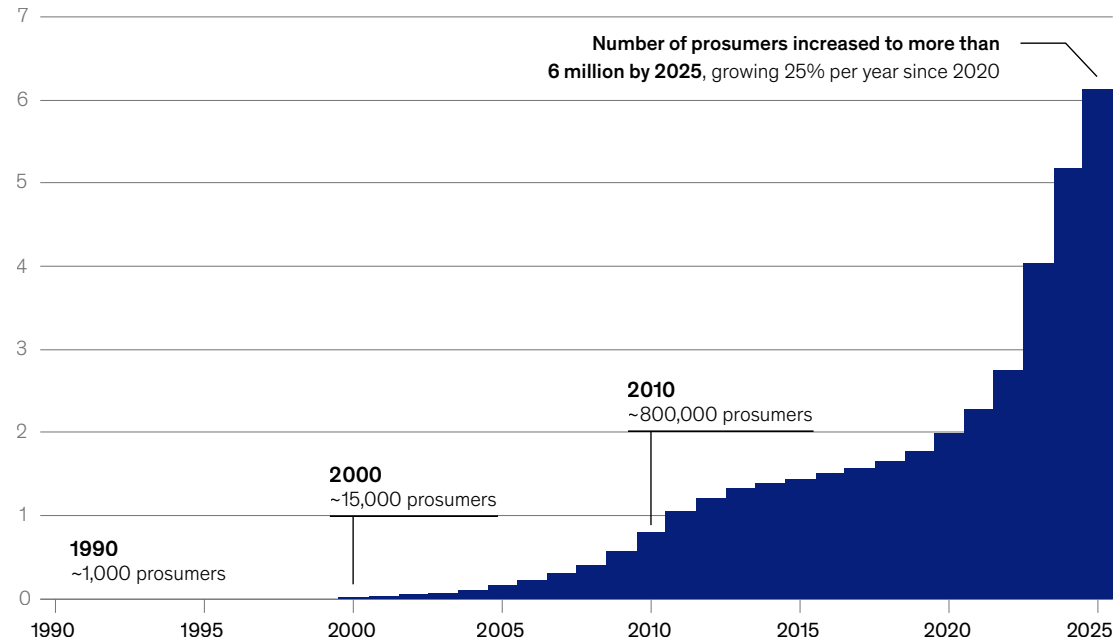
Historically, power systems relied on a limited number of large-scale generation assets, typically large coal, nuclear, gas, or hydroelectric plants, connected via relatively few grid interconnection points. The rapid expansion of distributed prosumers—electricity consumers owning rooftop solar photovoltaic (PV) batteries, EVs, and flexible heat pumps—has driven up the number of small-scale assets and connection points in recent years, making power systems increasingly decentralized, complex, and intermittent (Exhibit 8). According to Fraunhofer analysis of Marktstammdatenregister data, Germany had approximately 4.8 million registered solar PV installations in 2024, with about 1.47 million systems added in 2025 alone.⁴⁸

⁴⁸ Figures for 2024 consider PV assets above 800 watts. Marktstammdatenregister (Market master data register), the German official registry for energy assets, operated by Bundesnetzagentur (Germany's Federal Network Agency).

Exhibit 8

Germany's prosumer base has grown rapidly since 1990.

Cumulative number of prosumers with small-scale solar photovoltaic (PV) and storage assets in Germany, millions¹



¹ Considering the official German Federal Network Agency's Market Master Data Register (Bundesnetzagentur MaStR [Marktstammdatenregister] "Gesamtdatenexport" as of May 2026) and counting distinct plant operator location [Anlagenbetreiber-Lokation] pairs—ABR (the registered plant operator [MaStR-Nr. des Anlagenbetreibers]) plus SEL (the physical generation site [MaStR-Nr. der Stromerzeugungslokation])—associated with small-scale solar PV (gross output [Bruttoleistung] < 5 MW) and/or battery storage (usable storage capacity [nutzbare Speicherkapazität] < 10 MWh) that are currently in operation (Betriebsstatus [In Betrieb]). Each ABR plus SEL pair is counted once, in the year of its earliest eligible commissioning date [Inbetriebnahmedatum], so that multiple units, PV-plus-storage systems, and later battery retrofits at the same operator-location site are not double-counted—yielding a proxy for unique prosumer sites rather than an exact household count.
Source: Marktstammdatenregister, "Gesamtdatenexport" [Core Energy Market Data Register, "Complete data export"], Bundesnetzagentur

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This shift is accelerating the emergence of new aggregation-oriented businesses operating as a direct response to rising curtailment, localized grid congestion, and escalating system flexibility needs. These businesses—ranging from virtual power plant (VPP) operators to providers of distributed energy solutions—seek to capture value through the real-time orchestration and coordination of a diverse asset base, including BESS, EVs, heat pumps, home energy management systems (HEMS), prosumer generation, and industrial demand response.

Crucially, this orchestration model is no longer exclusively a residential (B2C) model. It is rapidly expanding into the commercial (B2B and small and medium-size enterprise [SME]) and public (business-to-government [B2G] and municipal) sectors. As localized grid bottlenecks become more common, commercial and municipal customers require sophisticated orchestrators to manage localized distributed generation, coordinate regional EV-charging infrastructure, optimize heat networks, and enable participation in emerging local flexibility markets. Beyond this, applying IT load orchestration across networks of data centers unlocks more spatial and temporal load flexibility, pushing the frontier of flexibility models further.

Companies such as Sympower in the Netherlands,⁴⁹ Flexitricity in the United Kingdom,⁵⁰ and FlexPower in Germany⁵¹ illustrate the shift toward aggregation, optimization, and commercialization of distributed energy resources. Sympower is a flexibility platform provider, aggregating distributed loads, batteries, and on-site assets across multiple customers and markets. Flexitricity operates a VPP, combining customer-side asset integration, control, aggregation, and market access for commercial and industrial clients. FlexPower's PowerMatch platform enables renewable producers, storage providers, and consumers to trade power directly through standardized PPAs, reducing friction in decentralized power procurement.

For incumbent utilities, the rise of aggregators challenges the traditional role of the supplier as the primary interface between customers and the energy system. As distributed energy resources expand, value is increasingly shifting toward the orchestration and optimization of connected assets. The strategic challenge for incumbents will be to determine whether and how to expand beyond traditional commodity supply, building the VPP capabilities, flexibility platforms, and energy ecosystems required to orchestrate assets across the B2C, B2B, and B2G segments. This decision carries profound implications across their existing businesses, requiring a radically different skill set in software and the Internet of Things.

In response to increasingly fragmented capacity and rising flexibility needs, large energy and infrastructure companies are acquiring specialized aggregation businesses as a faster way to build orchestration capabilities. Examples include energy2market (e2m), acquired by EDF in France to strengthen its position in decentralized energy management, which operates a VPP bundling around 5,000 decentralized systems.⁵² Flexcity, a Veolia subsidiary, aggregates electricity flexibility across Europe, with more than 10,000 sites and more than 2 GW of flexible power.⁵³ Other examples include Next Kraftwerke, an operator of one of Europe's largest VPPs acquired by Shell;⁵⁴ be.storaged, a battery storage and VPP services provider owned by EWE;⁵⁵ and Coneva, a provider of automated energy management and flexibility solutions owned by SMA Solar.⁵⁶

While these acquisitions provide the necessary asset base and market access, the true scaling of orchestration lies in the underlying technology. Advances in agentic AI could enable a new generation of retailer operating models built around automation rather than labor, replacing historically human-intensive activities (such as dispatch optimization, trading operations, customer servicing, billing and contract management, and grid coordination) with autonomous, software-driven workflows. For safety- and reliability-critical functions such as dispatch and grid coordination, human oversight and strong cybersecurity safeguards will be vital to oversee the automation. Unlike previous digital platforms that primarily streamlined existing processes, AI-native retailers have the potential to automate large parts of the retail value chain end to end. By significantly lowering operating costs and reducing barriers to entry, these models could accelerate new entry.

For incumbents, the strategic challenge is no longer just achieving a lower cost to serve; it is about defending who controls the customer relationship before third-party AI agents completely commoditize the retail interface. Yet it also creates an opportunity: Those that build the first truly AI-native platforms

⁴⁹ "About us," Sympower, accessed July 1, 2026.

⁵⁰ "About us," Flexitricity, accessed July 1, 2026.

⁵¹ "Über uns," [About us], FlexPower, accessed July 1, 2026.

⁵² "EDF acquires e2m and strengthens its position in the field of decentralised energy management in Europe," EDF, June 6, 2013; "Vision, mission, business model," e2m, accessed June 23, 2026.

⁵³ "Who we are," Flexcity, accessed June 23, 2026; "Enhancing power system resilience: Veolia passes the 2 GW of flexible power milestone in Europe," Veolia press release, January 23, 2024.

⁵⁴ "Shell acquires Next Kraftwerke to strengthen position in renewable energy trading," Next Kraftwerke, February 25, 2021.

⁵⁵ "be.storaged errichtet bundesweit Batteriespeicher mit 300 MWh Kapazität" [be.storaged builds nationwide battery storage with 300 MWh capacity], EWE AG, September 2, 2025.

⁵⁶ "SMA Solar Technology AG founds subsidiary Coneva GmbH for digital energy solutions," SMA Solar Technology AG press release, January 19, 2018.

could overtake digital attackers, strengthening their competitive position, deepening control of the customer relationship, and defending the high-value interface across retail and energy management.

This new wave of structural cost reduction in energy retail mirrors the historical evolution of customer service operating models. Having progressed from fully human call centers to traditional interactive voice response (IVR) systems, utilities are now entering a new phase of gen-AI-enabled autonomous support. By automating a growing share of customer interactions, the transition has the potential to reduce customer service costs by 40 to 70 percent, further lowering retail cost to serve (Exhibit 9).⁵⁷

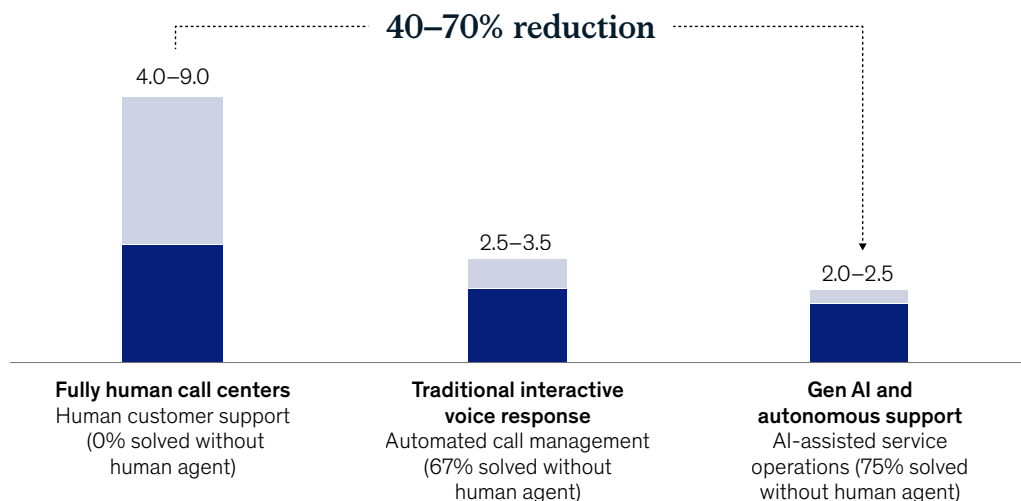
However, this is not just a route to lower cost to serve; it represents a fundamental shift in who controls the customer relationship. As the customer interface becomes increasingly commoditized, competitive advantage will shift away from legacy brand loyalty toward the quality of the operating platform, data access, algorithmic intelligence, and integration with agentic marketplaces. Against this backdrop, utilities face a strategic choice: build proprietary AI-enabled capabilities, adopt third-party platforms, or launch separate digital-native vehicles capable of competing on speed, cost, customer experience, agent-mediated demand, and real-time tariff optimization. Those that evolve from labor-intensive operating models to AI-native platforms may be better positioned to defend margins, scale new services, and capture value in an increasingly digital energy ecosystem.

⁵⁷ Analysis based on a McKinsey case study of a United Kingdom energy retailer, using 2024 estimates for fully human call centers, traditional interactive voice response (IVR), and intelligent automation, considering tech cost and human agent cost; upper bound of fully human call centers based on higher complexity of use case.

Exhibit 9

Cost-to-serve can be reduced significantly through gen AI.

Average cost-to-serve per inbound customer call, €



Note: The analysis is based on a case study of a UK energy retailer, using 2024 estimates for fully human call centers, traditional interactive voice response (IVR) systems, and intelligent automation. By considering technology costs and human agent costs, the retailer's mid-estimates indicate a potential cost reduction of ~60%. The upper bound of fully human call centers reflects the higher complexity of use case.

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3. Utilities could increasingly converge their energy supply with the token economy

The energy sector is on the cusp of a structural transformation that redefines its end product. For decades, the utility business model has centered on delivering physical energy commodities—selling the volume of gas molecules and the flow of electrons. But as the AI revolution accelerates, the ultimate value comes from shifting from the raw energy input to the computational output it powers. The most forward-thinking utilities will no longer be in the business of merely selling power; they will head toward enabling and trading computational capacity itself, moving into the emerging new downstream segment.

This shift is propelled by the rapid growth in AI, which is projected to account for about 70 percent of global data center capacity expansion, pushing total capacity beyond 250 GW by 2030.⁵⁸ Electricity is the binding constraint on this growth. To ease this bottleneck, energy companies are repositioning to be strategic enablers of AI infrastructure (Exhibit 10). To capture the full commercial upside of this shift, utilities may need to view the data center opportunity not as a single, binary choice, but as a spectrum of value creation. This progression spans four distinct levels of market participation, each demanding a more sophisticated set of capabilities and unlocking a progressively higher margin profile.

Commodity suppliers. At the foundation of AI data centers lie the site and energy infrastructure—the “powered land”—where utilities traditionally act as commodity suppliers providing standard grid connections and PPAs. However, remaining in this role means utilities risk missing out on high margins and becoming trapped in interconnection queues lasting three to five years, while value migrates downstream.⁵⁹

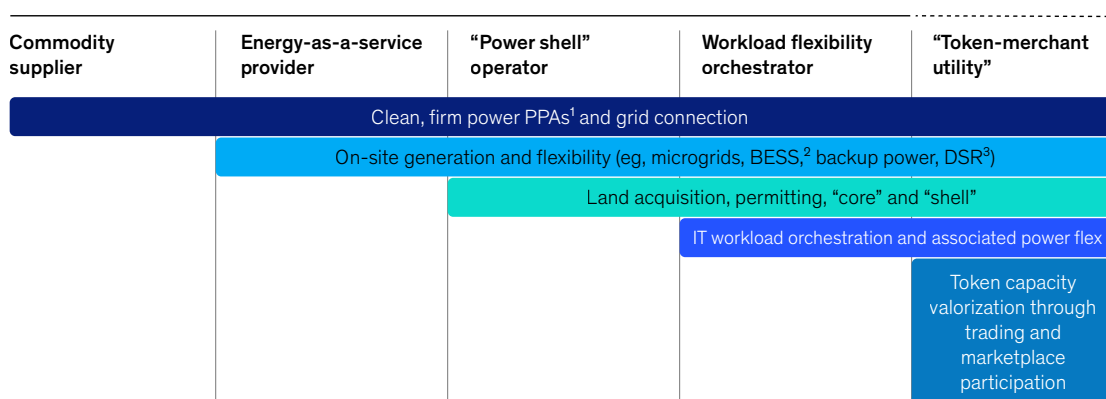
⁵⁸ McKinsey Proprietary Data Center Demand Model.

⁵⁹ *Queued up: Characteristics of power plants seeking transmission interconnection*, Lawrence Berkeley National Laboratory, December 2025.

Exhibit 10

A utility’s business model can evolve from selling electrons to trading in the token economy.

Levels of utility opportunity



¹Power purchase agreements.

²Battery energy storage systems.

³Demand-side response.

Energy-as-a-service model. To bypass these bottlenecks and move up the value chain, utilities are transitioning into energy-as-a-service models. Within the powered land, they provide additional technological building blocks, such as on-site generation, BESS, backup power, and DSR. In France, EDF has launched a strategic partnership with developer OpCore to build a several-100-megawatt high-power data center campus.⁶⁰ Rather than merely supplying electricity, EDF provides the fundamental power shell—leveraging its decommissioned industrial sites (such as the former Montereau-Vallée-de-la-Seine thermal power plant) to offer accelerated, high-voltage grid connections, dedicated low-carbon baseload power, and comprehensive infrastructure support, turning legacy land assets into a multibillion-euro strategic data center hub. In Finland, Fortum has integrated Microsoft’s data center into urban energy planning, capturing the facility’s waste heat and feeding it directly into municipal district heating networks.⁶¹

Power shell infrastructure providers. Some utilities are moving further, becoming power shell infrastructure providers. They offer hyperscalers and GPU-as-a-service (GPUaaS) providers turnkey, off-grid, or microgrid-connected sites where the land, energy connection, additional shell infrastructure (such as building structure, road access, and security perimeter) and, optionally, core infrastructure (such as cooling and electrical systems) are already built; the tech company simply brings the servers. In Europe, the largest example to date is the €2 billion joint venture formed in 2025 between Echelon Data Centres and Iberdrola. Under this partnership, Iberdrola, via its subsidiary CPD4Green, secures the land, provides the grid connection, and supplies 24/7 renewable energy, while Echelon designs, commercializes, and operates the sites, starting with the 144 MW Madrid Sur campus.⁶²

Orchestration of IT workload flexibility. Beyond physical infrastructure, utilities are moving into the software layer through the orchestration of IT workload flexibility. Real-time software can modulate AI compute, turning more than 10 percent of peak load devoted to flexible tasks such as AI model training into a dynamic grid asset.⁶³ This capability is already being demonstrated in major industry collaborations. For example, Emerald AI and National Grid have partnered to demonstrate AI power flexibility in the United Kingdom.⁶⁴ Google and Voltus have launched a VPP, aggregating up to 100 MW of distributed capacity in PJM Interconnection, the largest regional transmission organization in the United States.⁶⁵

Token-merchant utility. The ultimate realization of the token-electron convergence is the “token-merchant utility.” By integrating both physical infrastructure and IT orchestration, utilities can transition from selling electricity to participating directly in AI marketplaces. As utilities themselves become advanced IT and AI players requiring immense computational power for grid orchestration, market trading, and customer management, they are uniquely positioned not only to consume this capacity but also to supply and trade it. Instead of pricing contracts in MWh, these forward-looking utilities will trade raw computational capacity and AI tokens.

For utility leaders, the strategic logic rests on two reinforcing dynamics. First, the response commercializes assets that the utility is already best positioned to mobilize—secured interconnection, permitting and siting access, dispatchable generation, and orchestration software—at margins materially above commodity supply. Second, it offers a spectrum rather than a single bet: The energy-as-a-service and power shell layers

⁶⁰ “OpCore and EDF to develop a high-power data center,” InfraVia Capital Partners and EDF joint press release, November 17, 2025.

⁶¹ “Fortum has started heat production at two large data centre sites in Finland,” Fortum press release, May 6, 2026.

⁶² “Iberdrola and Echelon create a joint venture to develop data centres in Spain,” Iberdrola press release, July 28, 2025.

⁶³ Tyler Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell, *Rethinking load growth: Assessing the potential for integration of large flexible loads in US power systems*, Nicholas Institute for Energy, Environment & Sustainability, Duke University, 2025.

⁶⁴ “National Grid and Emerald AI announce strategic partnership to demonstrate AI power flexibility in the UK,” National Grid press release, September 15, 2025.

⁶⁵ “Voltus and Google to deliver grid capacity and local economic benefits through Bring Your Own Capacity agreement,” Voltus press release, June 2, 2026.

deliver multiyear, contracted, infrastructure-like cash flows from hyperscaler and GPUaaS partners, while the orchestration and token-merchant utility layers add platform-style upside through capacity markets and emerging compute marketplaces. This transforms the business model, shifting from selling a commodity input to capturing the high-value output of the AI economy.

4. Technology-enabler utilities could help bring next-generation technologies to scale

As governments prioritize greater energy independence, the limitations of existing technologies are accelerating investment in next-generation solutions that could reshape the market. Emerging technologies such as small modular reactors (SMRs), advanced geothermal, low-cost hydrogen, and nuclear fusion could complement today's renewables by providing firm generation, greater dispatchability, and higher energy density. These characteristics could help replace the reliability traditionally provided by conventional thermal generation and support a resilient, decarbonized power system. As a result, these solutions have attracted capital far faster than previous generations once they have reached early commercial scale, achieving similar funding levels in roughly three to nine years, compared with more than 15 years for earlier technologies such as solar PV.⁶⁶

However, utilities are unlikely to become technology developers in the venture-backed R&D sense. The technical, construction, and balance sheet risks of first-of-a-kind generation technologies are too large for individual utilities to carry alone. Instead, utilities can play a critical technology-enabler role: helping orchestrate the ecosystem of technology developers, industrial partners, offtakers, regulators, and governments required to bring down costs, secure permitting, build supply chains, and turn promising technologies into bankable infrastructure. Governments will remain central to derisking early deployment through funding, guarantees, state aid, regulated revenue frameworks, and strategic policy support.

Utilities are therefore managing a portfolio of strategic options across three time horizons. In the near term, advanced geothermal is closest to scaled deployment, supplementing today's operations. In the medium term, SMRs and low-cost hydrogen offer firm, sovereign power options as conventional fleets retire and demand grows. In the longer term, nuclear fusion represents an asymmetric bet—high uncertainty, but transformational if scaled. Utilities are securing these options through two approaches: development partnerships and targeted in-house R&D and codevelopment efforts, locking in critical future capabilities while mitigating early-stage risks, calibrating capital commitment and partnership intensity to each horizon.

1) Development partnerships. Partnerships with start-ups, technology developers, industrial companies, and public authorities allow utilities to share development costs and risks while limiting capital commitment until technologies move closer to commercial scale. Examples include:

- **advanced geothermal:** EnBW formed a joint venture (WärmeWerk Wörth) with Daimler Truck and the City of Wörth am Rhein in Germany to develop deep geothermal heat.⁶⁷ The German government supports and funds the project as part of the federal DEKAPALATIN-Bertha research project, contributing €20 million.⁶⁸

⁶⁶ McKinsey analysis based on data from the International Energy Agency (IEA), Fusion for Energy, and the Nuclear Energy Agency (NEA), analyzing the 20-year trend in cumulative investments after reaching \$1 million initial investment for SMRs, nuclear fusion, advanced geothermal, low-cost hydrogen, BESS, and solar PV.

⁶⁷ "Konsortialtreffen des geförderten Forschungsprojekts DEKAPALATIN" [Consortium meeting for the funded DEKAPALATIN research project], WärmeWerk Wörth press release, March 5, 2026.

⁶⁸ "Funding references 03EXP4005A and 03EXP4005F," EnArgus, accessed June 17, 2026.

- **small modular reactors:** ČEZ, a consortium partner with Rolls-Royce plc in Rolls-Royce SMR Ltd, is backed by the Czech government as a majority shareholder and is jointly developing with Rolls-Royce SMR the site application for modular reactors at Temelín in the South Bohemian region.⁶⁹ EDF is developing SMRs through NUWARD and an evolving industrial ecosystem, including Edvance, Framatome, and Tractebel.⁷⁰ NUWARD is a component of the France 2030 investment plan and has received €300 million in French state aid and European support.⁷¹
- **low-cost hydrogen:** Iberdrola formed a joint venture with bp to develop one of Europe's largest green hydrogen projects in Castellón, Spain,⁷² receiving €15 million in support from the European Union's NextGenerationEU through the Spanish Recovery, Transformation and Resilience Plan.⁷³
- **nuclear fusion:** RWE invested in a fusion start-up with the federal state of Hesse in Germany to develop a potential laser fusion hub. The German government plans to invest €9 billion in fusion technology up to 2037.⁷⁴

2) In-house R&D and codevelopment. Beyond partnerships, many utilities are building dedicated venture arms and R&D units to develop the capabilities needed to assess, shape, and deploy emerging technologies. With annual R&D investments that have been growing at 4.3 percent CAGR since 2005 (Exhibit 11), selected utilities are using targeted codevelopment and early-stage investment to influence technology evolution and secure proprietary access—calibrating commitment intensity to where each technology sits in the portfolio. Examples include:

- **advanced geothermal:** RWE Innovation Centre's R&D unit has developed projects focused on advanced geothermal technologies, including deep geothermal and mine water heat recovery.⁷⁵
- **small modular reactors:** EDF maintains a dedicated in-house R&D organization focused on next-generation energy systems, including advanced nuclear technologies such as SMRs and advanced modular reactors (AMRs).⁷⁶
- **low-cost hydrogen:** Engie New Ventures has invested in hydrogen start-ups, such as H2SITE that is developing membrane reactor technology for on-site, low-cost hydrogen production.⁷⁷

The strategic implications differ across these technologies. In the near term, scalable advanced geothermal could deliver firm low-carbon heat and additional dispatchable capacity to supplement existing operations. In the medium term, economically viable SMRs could provide stable low-carbon baseload generation (for example, the RoPower Nuclear's 462 MW SMR project in Doicești, Romania), and low-cost hydrogen could structurally reduce Europe's dependence on natural gas imports while enabling seasonal flexibility

⁶⁹ "Rolls Royce SMR and ČEZ Group partner to deploy SMRs in UK and Czechia," ČEZ press release, October 9, 2024; "National Wealth Fund commits up to £599m to Rolls Royce SMR," National Wealth Fund press release, April 13, 2026.

⁷⁰ "EDF announces the creation of its subsidiary NUWARD to boost the development of its SMR now entering the basic design phase," EDF press release, March 30, 2023.

⁷¹ "Commission approves €300 million French state aid measure to support NUWARD in researching and developing small modular nuclear reactors," European Commission press release, April 26, 2024.

⁷² "JV between bp and Iberdrola España has reached the final phase of construction of what will be the largest green hydrogen plant in Spain," Iberdrola press release, March 5, 2026.

⁷³ "bp & Iberdrola España announce final investment decision for largest green hydrogen plant in Spain," Iberdrola press release, September 12, 2024.

⁷⁴ "German laser fusion start-up attracts huge VC investment," Germany Trade & Invest press release, May 28, 2026.

⁷⁵ "Weisweiler geothermal energy," RWE, accessed July 1, 2026.

⁷⁶ "Leveraging AGR know-how for AMR success," EDF, November 10, 2025.

⁷⁷ "H2SITE raises 12,5M€ to scale membrane reactor breakthrough technology," Engie press release, June 30, 2022.

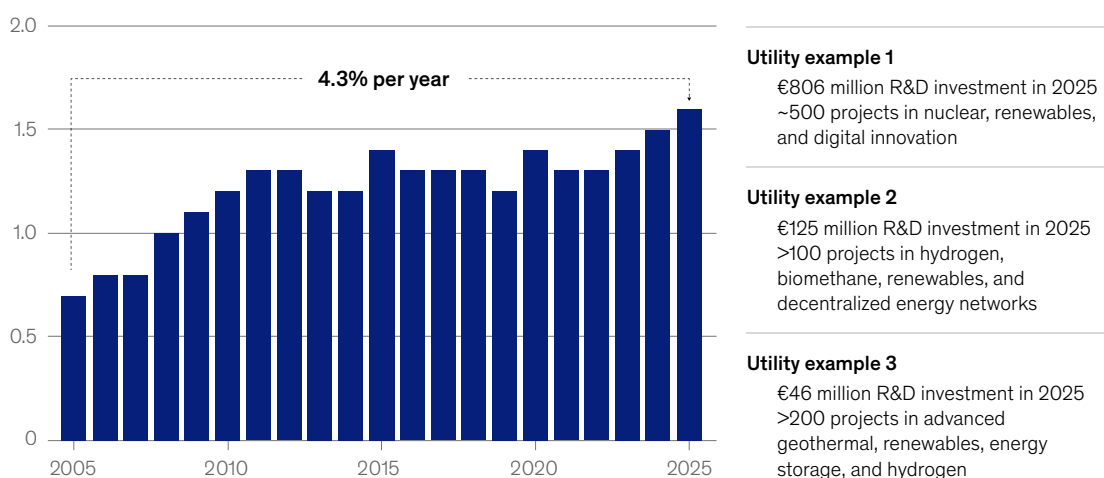
and industrial decarbonization. In the longer term, scalable fusion could reshape system stability. None of these technologies removes the need for major system investment; instead, they could add new connection, storage, and integration requirements, shifting part of the cost challenge toward networks and system orchestration.

In this environment, utilities increasingly require capabilities traditionally associated with technology companies: rapid experimentation, ecosystem partnerships, software integration, and accelerated innovation deployment. Yet, unlike venture-backed technology firms, utilities cannot shoulder the risk of pioneering prescale generation technology; they need to stage commitments over time, scale exposure only as technologies mature, and work with governments to create robust risk-sharing frameworks that turn selected options into bankable infrastructure.

Exhibit 11

Annual R&D investment by selected European utilities has grown steadily since 2005.

Annual R&D investment by selected utility companies,¹ € billion



¹Utility companies considered: ČEZ, EDF, EnBW, Engie, Fortum, Iberdrola, National Grid, RWE, and Vattenfall.
Source: EU Industrial R&D Investment Scoreboard; company annual reports

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Strategic implications for energy companies

The European power sector is undergoing a profound migration of value. Ultimately, the future utility landscape may be defined less by the sheer MW capacity of the physical assets owned by utilities and more by utilities' ability to control critical scarcities—grid access, system flexibility, firm sovereign capacity, powered digital infrastructure, and the digital customer interface. Said differently, Europe is not decentralizing energy; it is recentralizing control over a more decentralized system. This transition is being

propelled by four fundamental shifts: power market design changes to support affordability and sovereign energy security; persistently higher capital costs; rising flexibility requirements amid extreme curtailment, intermittency, and grid congestion; and technological advances, such as agentic AI, next-generation power, and token-electron convergence (Exhibit 12).

Exhibit 12

European utilities need to consider their value creation rationale, near-term priorities, and how to address main risks.

Translating utilities' four strategic responses into concrete initiatives

				
	Integrated utility 2.0 play	AI-orchestrator play	Token-merchant play	Tech-scaling enabler play
Value creation rationale	Maximize generation and commercialization synergies Stabilize the balance sheet by adding regulated grid infrastructure or other regulated-return assets to portfolios	Optimize capital and cost-light model for supply sourcing and commercialization by connecting 3rd-party supplies with automated demand-side management (acquired through very low, AI-enabled cost to serve)	Create and capture value from expanding energy infrastructure activities to data centers Commercialize indirect token exposure from energy supply (via trading, offtakes structuring)	Drive down cost (and improve time to market) of new technology deployment by taking an ecosystem integrator role Derisk project financing by providing commercial or tolling offtakes
Focus in next 12 months	Enhance commercial structuring capabilities exploiting flex-asset integration for commercialization products Define optimal portfolio composition to match investor profile; adjust RAB¹-based or CfD/FIT²-backed capex deployment to reach optimal merchant/RAB ratio	Transform B2C (and small B2B) retail portfolios through a rapid transition toward agentic AI-based service models Scale B2C VPP³ offers for demand-side flex (EV, HP, BTM-systems)⁴ Launch B2B highly specialized VPP and flex platforms (eg, data center IT workload orchestration)	Expand power-shell offers for data centers (ie, co-siting, BESS,⁵ backup generation, microgrids) Structure JV development with data center developers (eg, colocation providers, infrastructure funds, and potential hyperscalers) Launch token-trading desks within trading business units	Structure developer teams and roadmaps for most relevant next gen technologies (eg, deep-geothermal, SMR,⁷ fusion) Engage with leaders for each critical ecosystem role (OEMs,⁸ EPCs,⁹ auxiliary system providers, etc) and structure partnerships; bring relevant regulators and other decision makers to the table Optimize costs and launch flagship projects for real-life deployment
Action to address main risks	Invest in best-in-class commercialization capabilities to maximize generation valorization	Acquire or develop agentic AI-native platforms if in-house development is not taking off quickly Scale customers/VPP portfolio	Evaluate new operational and commercial risks, such as data center uptime SLAs⁶ with penalties, undeveloped token markets with initially limited liquidity, etc	Anchor time and resource investments into technologies and projects with credible cost down trajectories and clear regulatory support models

¹Regulated asset base. ²Contracts for difference/feed-in tariff. ³Virtual power plant. ⁴Electric vehicle, heat pump, behind-the-meter systems. ⁵Battery energy storage systems. ⁶Service-level agreements. ⁷Small modular reactor. ⁸Original equipment manufacturers. ⁹Engineering, procurement, and construction.

Navigating these disruptions prompts executive teams to evaluate their capability gaps, as value rapidly migrates toward four new strategic responses equipped to command these scarcities. First, integrated utilities are undertaking strategic economic rebundling across generation, trading, and retail to strengthen portfolio resilience and access to cheaper capital. Second, orchestrator utilities are integrating decentralized assets as a direct response to grid congestion and flexibility needs across B2C, B2B, and B2G segments, while disruptive AI-native and software-driven retailers automate end-to-end operations to commoditize the interface and seize control of the customer relationship. Third, token-merchant utilities are pioneering the token-electron convergence, bundling turnkey power shell infrastructure and orchestrating IT workloads to capture the massive value pool of AI data centers. And fourth, technology-enabler utilities are helping bring next-generation technologies to scale, orchestrating the ecosystem of developers, industrial partners, and governments needed to turn firm, sovereign power options into bankable infrastructure.

Rather than relying on historical blueprints, leadership teams need to translate one or more of these four strategic responses into concrete initiatives over the next 12 months. How organizations respond and how fast they can execute may determine who successfully captures value in the next era of the European energy transition.

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