ING

THINK Economic and Financial Analysis

Energy Outlook 2026

January 2026

Abundant supply amid a challenging transition

Follow us
@ING_Economics

Energy Outlook: Abundant supply amid a challenging transition

Gerben Hieminga
Senior Sector Economist, Energy
gerben.hieminga@ing.com

Warren Patterson
Head of Commodities Strategy
warren.patterson@ing.com

Coco Zhang
ESG Research
coco.zhang@ing.com

Nadège Tillier
Head of Corporate Sector Strategy
nadege.tillier@ing.com

Energy markets enter 2026 in a markedly more comfortable supply environment. Oil and gas fundamentals have loosened, European carbon markets are set for a structural tightening, and low carbon technologies continue to advance - albeit unevenly. Across the system, 2026 will be defined by the contrast between traditional energy abundance and the slower, more complicated rollout of transition technologies.

Oil: rising supply meets modest demand

Oil markets look decidedly bearish this year as OPEC+ ramps up production, pushing the global market into a sizeable surplus throughout 2026. Brent is forecast to average around $57/bbl, with broader pressure on prices and timespreads. Still, geopolitical uncertainty and supply risks could interrupt this bearish trend.

Gas: LNG expansion pushes Europe towards oversupply

European natural gas supply is set to improve in 2026 as LNG exports, especially from the US and Qatar, increase. TTF prices may average €30/MWh, with possible summer dips. Short-term volatility remains due to low storage, but the EU's Russian gas ban appears manageable with new LNG projects coming online.

CO2: EU ETS supply tightens sharply

Europe's carbon market will tighten sharply in 2026, with effective supply falling due to Market Stability Reserve (MSR) placements, maritime allowance cancellations, and the potential for fewer REPowerEU auctions. Prices are projected to average €84/tonne, but high speculative activity and policy uncertainties, such as delayed free allowance phase-outs, pose downside risks. Nonetheless, structurally, EU ETS supply is set to remain tight, supporting higher prices.

Renewables: solid growth but increasingly complex deployment

Solar and wind will see robust growth in 2026, but deployment is increasingly complicated by grid constraints, trade policies, and cost pressures. China dominates both solar and wind with a focus on industrial competitiveness. Europe and the US follow with different drivers: energy security in Europe and AI driven power demand in the US. While battery storage and manufacturing policy are playing a growing role, challenges with supply chains and economics persist. Despite these hurdles, renewables remain the fastest-growing part of the global energy landscape.

Carbon Capture and Storage: a year of value chain alignment

In 2026, CCS focuses on building transport and storage infrastructure, but capture deployment remains slow due to high costs and weak demand. Integrated value-chain models are emerging, with stronger policy support in Europe and revised incentives in the US. However, faster capture investment requires clearer mandates and stronger demand-side policies.

Hydrogen: progress stalled as costs rise and off-take lags

Hydrogen's rapid growth hopes have faded, with the sector stuck in a pilot phase. Costs remain high, demand is weak, and government support has dropped. This year, the world's attention turns to China, which has elevated hydrogen as a core pillar of its 15th Five Year Plan. China's large scale electrolyser buildout and new subsidy schemes could redefine global cost curves. However, trade restrictions mean Europe and the US may not fully benefit. In 2026, the focus is on advancing pilot projects toward final investment decisions, not on large-scale expansion.

European Utilities: stable cash flows, rising investments, and funding challenges

For Europe's utilities, 2026 brings steadier earnings but persistent financial pressure. Total sector investment is set to increase by 6%. Network operators face the largest financial strain: capital expenditure will reach 164% of EBITDA on average, far above self financing capacity. Regulators in several countries are shifting towards cost plus frameworks to ensure grid operators remain financially viable. Even so, external funding needs will stay high and utilities are expected to issue €70bn in bonds, supported by government guarantees, shareholder loans, and new investor partnerships.

Oil, gas & CO2 see an increasingly comfortable supply outlook

Warren Patterson
Head of Commodities Strategy
warren.patterson@asia.ing.com

Oil and gas prices are set to come under pressure this year as supply outstrips demand. However, there are clear supply risks facing the market, particularly when it comes to oil. Meanwhile, the European carbon market is set to tighten this year

Oil surplus is expected to peak over the first half of the year

Call 1: Oil prices set to fall further through 2026

We hold a bearish view on the oil market, with strong supply increases from OPEC+ leaving the global market in large surplus throughout 2026, while demand growth is expected to be fairly modest once again in the year ahead. The surplus is expected to peak over the first half of the year, but with a surplus forecast for every quarter of 2026, global oil inventories should build throughout the year, putting pressure on both flat prices and timespreads. We forecast that ICE Brent will average US$57/bbl in 2026.

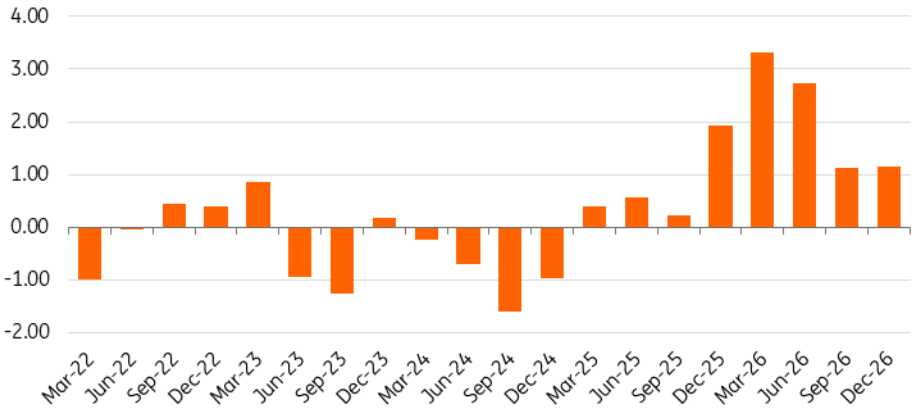
However, there are multiple supply risks to this view, given recent geopolitical developments. Firstly, there are still risks to Russian oil flows following US sanctions imposed last year. Russian exports are holding up for now, but it is taking longer for this oil to find a buyer, so we are seeing a growing amount of Russian oil at sea. If this continues, it should eventually feed through to lower Russian oil production, tightening up the market. However, for now, we are assuming Russian oil flows hold up and that supply chains adjust to these sanctions. This is something that Russia has managed to do well since its invasion of Ukraine. There will also be a lot of focus on how peace talks progress, with this having potential implications on Russian oil supply.

Supply risks have also re-emerged from Iran. Protests in the country and the potential for intervention are a risk to Iranian oil supply. Iran pumps around 3.2m b/d, so disruptions would be felt by the market. US President Donald Trump has announced plans for a 25% tariff on any country “doing business” with Iran, which may leave buyers of Iranian oil more reluctant to continue these purchases. However, China is the largest buyer of Iranian oil, and previously, the threat of secondary tariffs for purchases of Venezuelan and Russian oil was not enough to persuade China to reduce its purchases

of oil from these countries. So, we are assuming the same when it comes to Iranian flows. In addition, with the US and China having reached a trade truce, we have to question whether President Trump would put this truce at risk by imposing further tariffs on goods from China. The bigger concern for the market is if we were to see military intervention in Iran, putting Iranian supply at risk and elevating regional tensions.

Developments in Venezuela pose some risk to oil supply in the short term. However, the market is more focused on the long-term supply growth we could see from Venezuela. The country produces around 900k b/d, and we expect growth in the short term to be very limited. It would take several years and significant investment to see more sizeable supply growth, which would have a more meaningful impact on the market. But this may prove difficult given Venezuela's unattractive investment environment, and the bearish outlook for the oil market does not help.

The global oil market is set to be in large surplus through 2026 (m b/d)



Source: ING Research, IEA, EIA, OPEC

Call 2: LNG supply ramp to leave European gas market comfortable

The medium to long-term outlook for the European natural gas market is bearish. The ramping up of global LNG export capacity will push the global LNG market into surplus, putting further downward pressure on European gas prices. We expect TTF to average EUR30/MWh in 2026, with more downside in the second and third quarters.

However, in the near term (remainder of the 2025/26 winter), we believe the market will remain well-supported, and there is the potential for prices to move higher. This is due to the fact that EU gas storage is well below the five-year average, and we believe storage could end this heating season at around 25% full, reaching levels similar to those in 2022 and leaving the market more vulnerable. In addition, investment funds entered the 2025/26 winter with record short positions in TTF, which leaves the market at risk of a short covering rallying if we were to see any supply shocks or extended cold spells.

The EU ban on Russian gas, which will ultimately see Russian gas flows to Europe stopping by 1 November 2027 at the latest, should be manageable. The EU imported around 16bcm of Russian pipeline gas via Turkstream in 2025, while LNG imports from Russia totalled almost 20bcm over the year. The LNG ban will likely lead to an adjustment in trade flows, while replacing pipeline flows should also be manageable, given the ramping up of LNG export capacity.

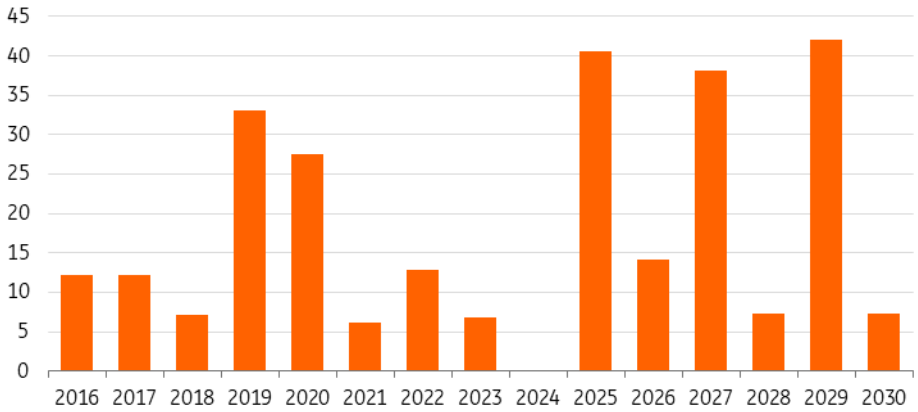
Between 2025 and 2027, the US has around 93bcm of LNG export capacity scheduled to start up, while from late 2026, we should also see significant capacity start-ups from Qatar, ensuring more than adequate supply for the EU. How adequate this supply will be depends on how Asian LNG demand performs through 2026. Asian demand was weak last year, due largely to China, where high inventories, stronger pipeline flows and weaker consumption weighed on LNG demand. And with plans for further pipeline

capacity into China in the medium to long term, Chinese LNG demand may remain more modest than initially expected.

The surplus environment that is expected means that the global LNG market may try to resolve the surplus by trading down to levels where we see US LNG plants reducing operating rates. Basically, we could see the market trading down to the short-run marginal cost (SRMC) for US LNG producers at times during the peak of the surplus expected in 2027 and 2028. This is a floating level which will depend on where Henry Hub is trading, but assuming Henry Hub trading around US$4/MMBtu (not too far from calendar 2027 prices), it would equate to around EUR18/MWh.

A key downside risk to our price forecasts would be a scenario where a peace deal between Russia and Ukraine ultimately sees the resumption of some Russian gas flows to Europe. While we believe a restart of Russian gas flows is unlikely, this scenario cannot be ruled out.

Significant US LNG export capacity set to start up (bcm)



Source: EIA, ING Research

Call 3: European allowance supply to drop significantly in 2026

European allowances (EUAs) have seen significant strength in recent months, with investment funds having built a record net long in the market. The constructive outlook for EUA prices is supported by expectations of a significant tightening in supply through 2026. However, the sizeable fund long leaves the market vulnerable to a pullback if we see funds taking profits.

Allowances under the EU ETS are set to fall significantly in 2026 – although if we look at the current auction calendar for 2026, it does not reflect this, with auctioned volumes set to fall by less than 1% year-on-year. However, the auction calendar for 2026 does not take into consideration several adjustments that we will see.

First, we are likely to see volumes reduced with allowances placed into the Market Stability Reserve (MSR) between 1 September 2026 and 30 August 2027.

Second, there will be some cancellation of maritime allowances in 2026, which will be equivalent to the difference between the number of allowances surrendered and verified emissions for the sector. This cancellation will result in a reduction in auction volumes.

Finally, 93.3m allowances are set to be auctioned in 2026 for REPowerEU. However, we believe this full volume will not need to be auctioned to hit the Commission's €20bn revenue target under REPowerEU.

Combining all these factors suggests a steeper decline in supply next year, which should be supportive for prices. We expect EUAs to average €84/tonne in 2026, up from an

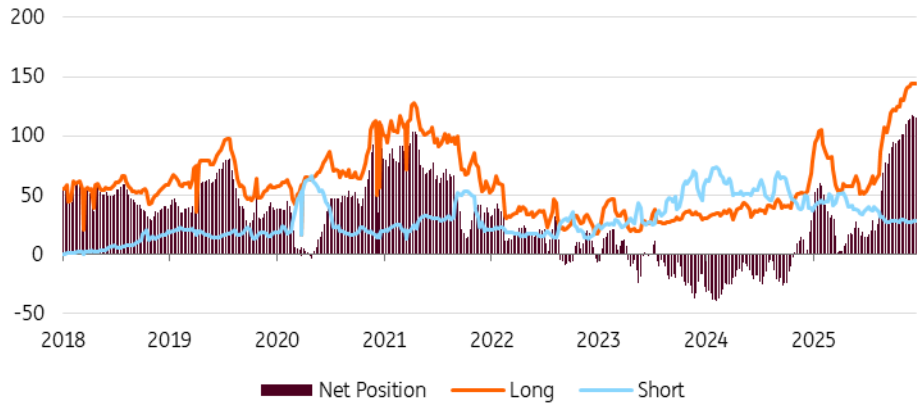
average of around €75/tonne in 2025. If speculators continue to show a healthy appetite to buy the market, this leaves upside to our forecasts.

Meanwhile, we will start to see the phasing out of free allowances for Carbon Border Adjustment Mechanism (CBAM) sectors and the full phasing out of free allowances for the aviation sector. In addition, the maritime sector will see 100% of its emissions covered in 2026, up from 70% in 2025.

There are clear downside risks facing the EUA market. There have been some member states pushing for a delay in the phase-out of free allowances under CBAM, highlighting concerns within the region over the competitiveness of European industry. If these concerns grow, we cannot fully rule out steps that may delay the EU's decarbonisation ambitions, which could mean the bullish outlook for EUAs may need to be dialled back.

We have already seen the EU decide to delay the implementation of ETS2, which will cover road transportation and buildings, from 2027 to 2028. While part of the delay was political, there was also a social element, given concerns over higher energy costs.

Investment funds enter 2026 with a record net long in EUAs (000 contracts)



Source: ICE, ING Research

ING forecasts

	1Q26	2Q26	3Q26	4Q26	FY26
ICE Brent (US$/bbl)	58	56	58	54	**57**
TTF (EUR/MWh)	33	28	27	30	**30**
EUA (EUR/t)	85	80	84	86	**84**

Source: ING Research

Renewables growth driven by shifting priorities

Coco Zhang
ESG Research
coco.zhang@ing.com

Gerben Hieminga
Senior Sector Economist, Energy
gerben.hieminga@ing.com

Global solar and wind power generation is set to grow robustly this decade, led by rising demand and efforts to enhance energy security and competitiveness. But there are risks, including tariffs and grid limits. Even so, we will see increased battery development in 2026 to support growth

China and Europe have both the strongest growth outlook within the same period for wind-generated electricity

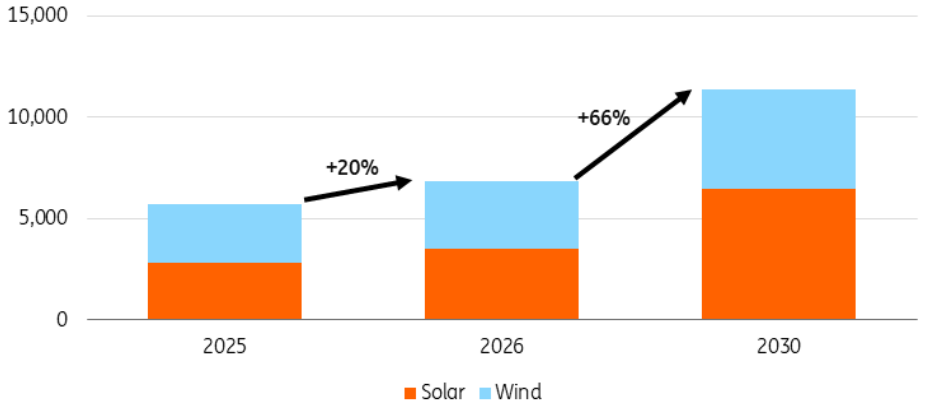
We've entered an era in which electrons are fuelling technological advancement and economic growth. Solar and wind power, with their increasingly competitive costs, abundant supply, and clean nature, are well-positioned to play a vital role. In this outlook, we highlight our top three calls on the opportunities and risks for the global solar and wind market.

Call 1: Shifting priorities are driving robust solar and wind power generation

Electricity generation from solar and wind will grow steadily this decade. The International Energy Agency (IEA) projects that global solar and wind power generation will grow by 20% in 2026 and an average annual increase of 15% from 2026 to 2030 under its Stated Policies Scenario (STEPS), which reflects current policies and achievable policy goals. Bloomberg New Energy Finance is relatively more bullish, expecting 17% annual growth in both power generation and installed capacity in its Economic Transition Scenario.

Given policy and geopolitical uncertainties in some regions, we lean towards the IEA's STEPS forecast. But both outlooks show robust growth despite the turmoil.

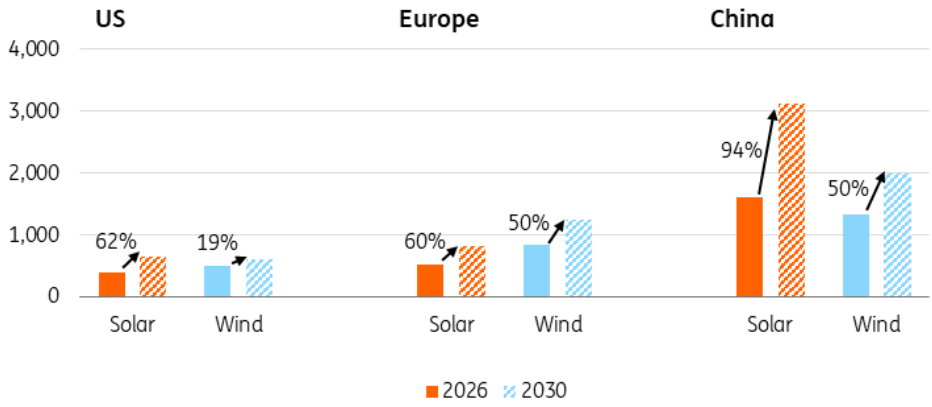
Solar and wind's steady growth
Global solar and wind power generation forecast in TWh



Source: ING Research, IEA

growth in solar power generation, at 94% from 2026-2030. For wind, China and Europe both have the strongest growth outlook within the same period, at 50%. While the US outlook for solar is slightly higher than Europe's, its weak spot is wind at only 19%.

China leads solar and wind development
Solar and wind power generation forecast by region in TWh



Source: ING Research, IEA

The main drivers of solar and wind growth have shifted beyond sustainability. AI, energy security, and strategic competitiveness have become the strongest engines.

> *"AI, energy security, and strategic competitiveness have become the strongest engines for solar and wind growth."*

- For the **US**, the demand is driven by AI's growing electricity needs. With shorter build times and fewer supply chain hurdles, renewables are becoming a 'bridge' until more dispatchable sources, such as gas and nuclear power, come online. Technology companies are also buying more renewable power to manage emissions from higher power use.
- In **Europe**, growth is driven by energy independence. The Russia-Ukraine war pushed Europe to reduce its reliance on Russian gas and cope with higher gas prices, which in turn favours the buildout of renewables. Decarbonisation remains an important driver, though the focus has shifted to strategic autonomy, affordability and innovation.
- **China's** renewables market will be sustained by its absolute advantage in manufacturing solar and wind equipment – and its target to reduce emissions by 7-

10% from peak levels by 2035. This means China will push full-speed ahead with renewables.

However, on the supply side, regions face different challenges in 2026.

- **Europe's** main risk is grid constraints from limited transmission and interconnection capacity, which can restrict deployment. On the positive side, member states will implement the EU's new Grid Package to modernise infrastructure. Project economics remains solid generally, though offshore wind has weakened due to higher costs and lower power prices. This should drive wider use of 'contracts for differences' to stabilise revenues and improve auctions.
- The **US's** top risk is tariffs, which will reshape supply-chain partnerships (see Call 3) and permitting. This could mean tougher approvals and high-profile project cancellations, especially in offshore wind. The One Big Beautiful Bill Act (OBBBA) is of less concern, as many top-tier developers have secured tax credits through 2030. Overall, we still expect solid market development despite lowered expectations.
- **China** faces fewer supply chain and grid issues. Its challenge is adapting to last year's shift from fixed tariffs to market-based auctions. While this will benefit the market in the long term, developers now face pressure to lower bidding prices and margins. Developers need to enhance cost efficiency, innovation, and strategic optimisation – key factors to watch this year.

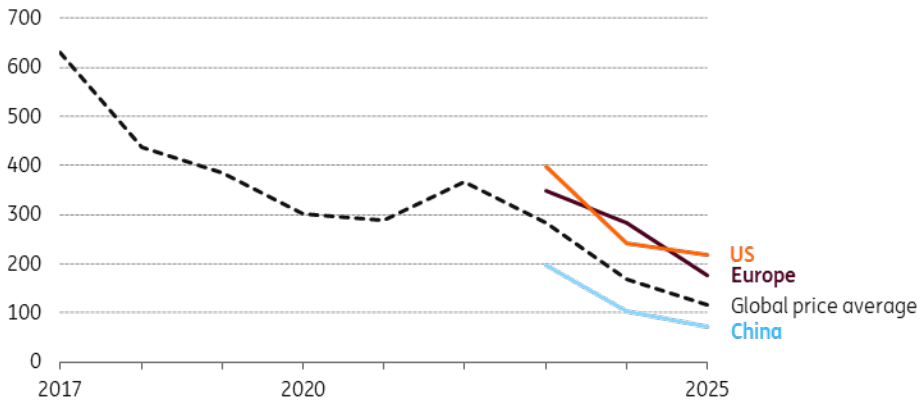
Call 2: The pressing need for more renewables will boost the storage market

Addressing the intermittency of solar and wind power isn't new, but 2026 will see a stronger push. More than ever, the industry sees adding battery energy storage systems (BESS) as a crucial solution for sustaining the future of solar and wind. Doing so can boost revenues by enabling a wider range of services and reducing curtailment. And in some cases, BESS is simply a prerequisite for building renewables in areas with grid congestion.

> *"More than ever, the industry sees adding BESS as a crucial solution for sustaining the future of solar and wind."*

Thanks to advances in technology, BESS costs declined, disruptively, by 61% from 2020-2025.

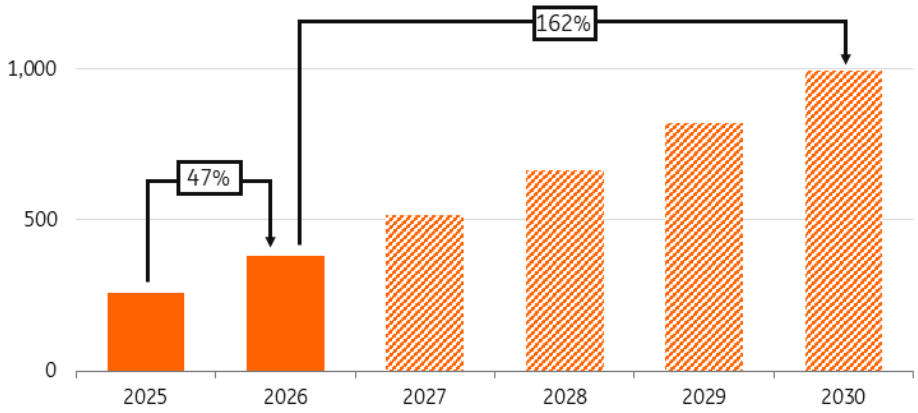
Battery storage system costs continue to decline
Surveyed prices for turnkey BESS in $/kWh (real 2025)



Source: BNEF, ING Research

We expect this trend to continue in 2026 and beyond. Combined with rising demand, it's expected to result in a 31% annual increase in installed capacity through 2030. China is set to account for 46% of the global capacity in 2026, thanks to its advantages in BESS costs and deployment. This share will decrease slightly this decade as other countries ramp up production. In the US, for instance, a survey by Roth Capital Partners shows that major solar developers expect the share of storage attached to their projects to increase from 26% in 2026 to over 50% in 2030.

BESS deployment remains strong this decade
Global cumulative BESS installed capacity forecast in GW



Source: BNEF, ING Research

These forecasts hinge on the assumption that geopolitical tensions do not escalate into a full-blown trade war over rare-earth elements critical to battery systems.

However, there are other challenges. The biggest, which we discussed in last year's Energy Outlook, is the duration of battery discharge time. The batteries available today offer only four hours of discharge time – which isn't long enough. Long-duration energy storage solutions (LDES) offer promising potential but remain costly and limited, making them unlikely to have a major market impact in 2026. On the positive side, policy is supportive in many jurisdictions to increase the commercialisation of LDES. In the US, the OBBBA has preserved battery tax credits until the next decade, though the qualifying conditions would become tougher over time.

Lithium-ion phosphate (LFP) batteries remain the main choice for BESS, whereas electric vehicles will mainly rely on other lithium chemistries such as Nickel Manganese Cobalt (NMC) batteries. This is because LFPs have a longer cycle life and lower costs since they avoid nickel and cobalt. There's now increased development of sodium-based batteries, as sodium is more abundant and therefore cheaper than lithium. Sodium-based batteries will be a meaningful niche for BESS. Its market share will grow this decade, but will likely remain in the mid-single digits.

Call 3: Strategic choices needed: boosting local production vs rapid and cheap expansion

Both Europe and the US have introduced policies to strengthen domestic solar and wind manufacturing. However, in the near term, shifting away from cheap Chinese products – which supply 98% of the EU's solar panel imports – could raise costs, disrupt supplier partnerships, and slow installations. In 2026, balancing long-term industrial gains with short-term, cheaper imports will become more challenging.

> *"In the near term, shifting away from cheap Chinese products could raise costs, disrupt supplier partnerships, and slow installations."*

To enhance domestic manufacturing, the **US** will rely heavily on tariffs, while the EU will focus on implementing the Net-Zero Industry Act (NZIA) as its primary tool, without tariffs.

For the US, tariffs will reshape solar and wind supply chains this year. In 2025, the US imposed steep solar tariffs – averaging 350% to 670% – on Cambodia, Thailand, and Vietnam, which supply a significant share of US imports. A 50% tariff was also imposed on steel-derivative products, which included wind towers and nacelles. Lastly, the US began investigating solar imports from India, Laos, and Indonesia, suggesting that additional tariffs could be imposed on these countries.

The **EU**'s risk of supply chain disruptions is lower because of limited tariff measures. But the bloc is wary of the lion's share of Chinese solar equipment flowing in. In December 2025, Italy became the first EU country to have a solar auction that banned Chinese-made modules, cells, and inverters. We expect more countries to add auction rules in 2026, either through an outright ban on Chinese components or, more modestly, by prioritising EU-made components.

While these measures support domestic manufacturing, the benefits will take time to materialise. In the short term, solar manufacturing in both regions would be barely self-sufficient, though wind is in better shape. Plus, despite growing solar module capacity, cell and wafer capacity will remain low. This makes it difficult to establish a fully integrated supply chain.

Assessing the dependence of US and European solar and wind manufacturing on foreign production

Equipment	US	Europe
Solar		
Modules	🟡	🟡
Cells	🔴	🔴
Wafers	🔴	🔴
polysilicon	🟡	🟡
Wind		
Nacelles	🟢	🟢
Blades	🔴	🟢
Towers	🟢	🟢

🟢 Low dependence on foreign production
🟡 Medium dependence on foreign production
🔴 High dependence on foreign production

Source: ING Research, IEA, US Department of Energy

Additionally, increased supply-chain turbulence awaits in 2026. For the **US**, while elevated tariffs can give domestic solar modules a price advantage, it can be time-consuming for developers to renegotiate supplier partnerships. It can be costly, too, as surging demand for US solar components can drive up prices.

For **Europe**, excluding Chinese or prioritising European components could raise project costs. In Italy's case, by 17%, according to BNEF's estimates. Meanwhile, funding under the NZIA appears insufficient to attract significant private investment. Therefore, EU solar manufacturing capacity is unlikely to grow substantially in the near future.

China, the global leader in renewables manufacturing, faces different challenges. Tariffs and overcapacity are hurting export competitiveness, squeezing margins and driving consolidation. These risks are expected to materialise in 2026 and persist for several years.

Taken together, despite uneven progress and varied challenges, solar and wind will continue to grow in 2026, strengthening their role in the global energy system.

Carbon capture and storage enters a new era of progress

Gerben Hieminga
Senior Sector Economist, Energy
gerben.hieminga@ing.com

Coco Zhang
ESG Research
coco.zhang@ing.com

In 2026, Europe is set to expand its CO2 transport and storage infrastructure while demand for CO2 capture is likely to remain more subdued. Despite persistent policy obstacles and geopolitical tensions, the sector is still expected to make steady progress, as expanding the CCS supply chain is a complex, multi-year endeavour

In recent years, it has become clear that the total costs associated with capturing, transporting, and storing CO2 are significantly higher than originally expected,.

Call 1: The year of value chain alignment amid mixed policy support

In 2026, carbon capture and storage (CCS) is set to shift towards integrated progress across capture, transport, and storage of CO2. Previously, each segment advanced largely on its own, exposing projects to greater risk and creating a chicken-and-egg problem: emitters were reluctant to invest in CO2 capture without guaranteed transport and storage capacity, while transport and storage operators were unwilling to build capacity without firm capture commitments. The next phase of CCS depends on aligning these segments so that emitters, transport operators and storage providers can plan with more confidence.

Building the CCS value chain
Aligning progress on each part of the value chain

Source: ING Research

A clearer division of roles is emerging. Emitters are increasingly focusing on operating their own capture facilities, while specialised operators handle the transport and storage of CO2. This model is taking shape across regions, though the policy frameworks that support it vary significantly. In the UK, regulated revenue contracts are in place to shield transport and storage operators from under-utilisation risk. Norway's Northern Lights operates on a pay-per-use basis, while the Dutch Porthos project uses fixed capacity agreements with some flexibility.

While these approaches help clarify the local business case, investors require a thorough understanding of each region's specific policies and risk structures. As we approach 2026, business models will continue to be refined, with risk-return profiles evolving to reflect the preferences of different actors within the CCS supply chain.

Policy uncertainty in the US

The US picture has been complicated by US President Donald Trump's One Big Beautiful Bill Act, which has left its mark on the CCS sector (although less so compared to offshore wind or hydrogen. The Department of Energy's cancellation of $3 billion in industrial demonstration grants (including $1.2 billion for CCUS) and the potential loss of $7.5 billion in awards have disrupted capture projects and threatened the carbon credit market. Transport and storage progress is mixed: the EPA has sped up Class VI permit approvals, and Texas can issue new permits, but states like Louisiana have enacted moratoriums. Major pipeline projects, such as Summit Carbon Solutions, face ongoing legal and logistical hurdles.

A key growth opportunity is supplying low-carbon power to hyperscale data centres run by Google, Microsoft, Meta, and AWS, which still intend to meet net-zero targets by 2030. The 45Q tax credit requires at least 75% CO2 capture and high plant use. With current gas plant utilisation at only 56% on average, long-term power purchase agreements with must-run data centres are needed to ensure sufficient run times. These are now entering the market. Google, for example, agreed to purchase power from a gas plant with CCS in a first-of-a-kind deal last October. More recently, NextEra and ExxonMobil revealed plans for a 1.2 GW natural-gas plant with CCS designed specifically to serve data centres.

Increased support in Europe

Europe, meanwhile, is advancing its CCS agenda. The EU's Net Zero Industry Act requires major oil and gas companies to achieve 50 Mtpa of CO2 injection by 2030, but this goal faces enforcement and planning challenges. Progress is most notable in the North Sea countries.

Norway leads the way with 13 storage licences on its continental shelf and open facilities for international emitters, supporting cross-border supply chains. In 2025, Germany passed a revised Carbon Dioxide Storage and Transport Act, enabling commercial-scale CCS and pipelines, including offshore storage and state opt-in for onshore. Germany also launched a €6 billion Carbon Contract for Difference auction for 2026, which will include CCS for sectors like (m)ethanol, steel and cement.

The UK is also moving forward, with projects like HyNet and Teesside now under construction. The UK government has allocated £21.7 billion ($28 billion) for CCUS; the distribution is still to be clarified. The UK's approach aims to improve infrastructure utilisation and reduce costs, with a goal of storing 20-30 Mtpa of CO2 by 2035.

Overall, ongoing policy support and projects under development are expected to move the market forward in 2026, but costs remain a challenge.

Call 2: Increased focus on cost reduction, but short term potential is limited

In recent years, it has become clear that the total costs associated with capturing, transporting, and storing CO2 are significantly higher than originally expected, now ranging from €50 to €300 per ton. As is often the case with emerging technologies, early expectations were overly optimistic, while rising energy, material, and labour expenses have further driven up costs.

CCS costs across the value chain are typically in the $100-$250 range per ton CO2
Costs drivers for CCS

	Capture CO_2	Transport CO_2	Permanent storage of CO_2
Cost factors	• CO_2 **concentration** of gas stream • **Scale** of facility • Modular versus custom **design** • CCS on existing plant or new **plant** • Local energy, water and capital **costs**	• **Pipeline** transport is generally cheapest and capex driven • Transporting CO_2 by **ship, rail, or truck** is typically more expensive and driven by operating costs (energy). Moreover, the sector is still evolving, with ongoing innovation before standardized ships, trucks, and rail carriers become widely available.	• **Offshore** storage (common in Europe) can be up to three times as costly compared to **on land** storage (common in the US and Danmark). And nearshore is more expensive than far shore. • **Reservoir capacity and quality**: storage in empty oil and gas fields is generally cheaper compared to saline aquifers or mineralisation in rock formations.
Indicative examples	Wide range of CO_2 capture costs; capture from bioethanol plants costs $30-40/tCO_2$ compared to $60-120 from power plants	Transport costs differ widely, for example from $10 to $75/$tCO_2$, based on transport mode, transport distance and utilization.	Storage costs add another $10-$100/tCO_2.
CCS cost range over full supply chain	$50-$300 per ton CO_2 with many projects currently in the **$100-$250** range		

Source: ING Research based on BNEF, Rystad, DNV, ZEP, EC and IEA

Current costs are substantial, and opportunities for rapid cost reductions remain constrained

High costs present a greater obstacle to widespread CCS adoption than technical challenges. Many projects currently fall within the $100 to $250 cost range, with ethanol and ammonia at the lower end and cement and steel at the higher end. This makes CCS heavily dependent on government support such as subsidies, carbon pricing, or tax incentives. In turn, lowering costs is critical for creating sustainable business models and ensuring the sector's long-term viability.

According to DNV, an international technical advisor and assurance provider across the entire CCS value chain, average CCS capex costs could drop by 14% by 2030. By 2050, costs could fall by as much as 40%, mainly due to economies of scale, standardised design, and technological improvements in CO2 capture. Operating costs could also decline gradually as CCS scales, but these advancements are partially offset by rising material and labour costs. However, these benefits mostly apply to new CCS facilities. Retrofitting older plants is more difficult, especially if their remaining operational life is short, limiting the time to recover costs.

Lowering costs comes with political trade-offs

Implementing a cluster-based approach that leverages scale and proximity is key to rapidly reducing CCS costs, as increasing the number of users within each cluster helps prevent underutilised CO2 infrastructure. However, this strategy presents important trade-offs for policymakers.

First, focusing on cost reductions in existing clusters before expanding to new ones may be efficient, but it can slow progress in other regions that also need to cut emissions. The UK illustrates this dilemma; prioritising the rapid expansion of track-1 sites (HyNet and Teesside/Humber) can maximise economies of scale and lower costs, but may delay development in track-2 sites such as Scotland's Acorn and Northeast England's Net Zero project.

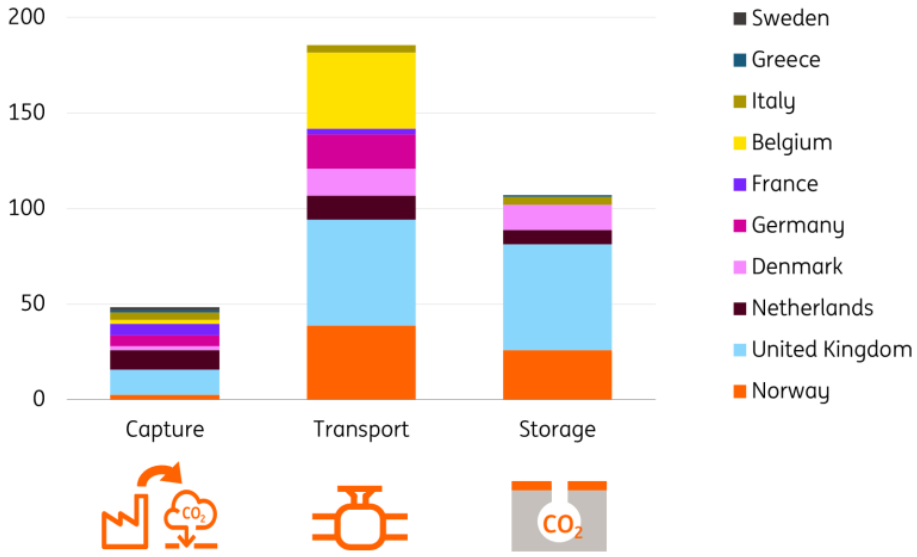
Second, the direction of industrial policy is crucial, as high energy prices threaten deindustrialisation and can impede CCS uptake, especially in Europe. This risk is heightened for globally competitive sectors like ammonia production (fertilisers) and refineries (fuels and chemical feedstocks), where CCS capture costs are relatively low due to concentrated CO2 streams. Involving more regionally focused industries, such as cement production and waste incineration, could reduce the risk of deindustrialisation, but may lead to higher overall CCS costs.

In 2026, policymakers will need to make more explicit decisions regarding these trade-offs. Without clear guidance, market participants are likely to factor these risks into the pricing of CCS across different clusters and projects.

Call 3: Strong momentum on the supply side, but don't forget about demand

In 2026, significant momentum exists on the supply side of CCS, with progress in storage and transport infrastructure, often state-backed. However, the major challenge is securing commitments from heavy industries to adopt CCS. By 2030, Europe is set to have much greater CO2 transport and storage capacity than actual CO2 capture. While it is natural for infrastructure development to precede emitter investments – since companies are unlikely to commit to capture facilities without reliable transport and storage options – the current disparity suggests a need for more coordinated efforts. Bridging this gap over the next few years will be critical for ensuring that investments in CO2 transport and storage infrastructure deliver maximum value by meeting adequate capture demand.

CO_2 Capture falls behind rapid expansion of transport and storage infrastructure
Capacity along the CCS supply chain in million tons CO2 per annum



Source: ING Research, based on Bloomberg New Energy Finance

Providing demand-side certainty – through mandates for green products or carbon intensity rules – could strengthen the business case for CCS. A further challenge is the contract length mismatch; emitters seek short-term deals, while operators want long-

term commitments for their assets that last multiple decades. A government-backed intermediary could bridge this gap by taking on contract duration risks.

Watch developments in voluntary carbon markets in 2026

An encouraging development is that CCS is increasingly applied to bio-energy plants, resulting in negative emissions (bioenergy with carbon capture and storage, or BECCS). This is spurred by developments in voluntary carbon markets, where tech companies and airlines are willing to pay substantial premiums for verified negative emissions credits. This is further amplified by the fact that enthusiasm for direct air capture (DAC) – which created machine-based rather than nature-based negative emissions – has diminished significantly. For example, recent policy shifts in the US have threatened to revoke $3.5 billion in DAC hub funding, and venture investment in the sector has dropped by 76% in 2025.

.

Hydrogen stuck in the pilot phase

Hydrogen's advancement has stalled, with numerous project cancellations, high costs and sluggish demand. China may lead the way for global adoption in 2026, but scaling remains a complex, multi-stage process. Current efforts should focus on pilot projects reaching final investment decision (FID), which requires solid demand

Gerben Hieminga
Senior Sector Economist, Energy
gerben.hieminga@ing.com

Coco Zhang
ESG Research
coco.zhang@ing.com

Establishing hydrogen as a mainstream commodity is a complex, multi-stage process that will unfold over several decades.

Last year, we expected the hydrogen industry to move beyond hype and into meaningful execution. While the initial excitement has certainly faded, 2025 turned out to be a challenging year for actual project implementation. Around 50 projects have been publicly cancelled, but the real number is higher as many cancellations happen silently. Unexpectedly, cancellations were not limited to paper-only projects. One developer, for example, actually dismantled two hydrogen plants – one in Australia and another in the United States – and returned millions of dollars in government grants, effectively turning the financial support into a liability.

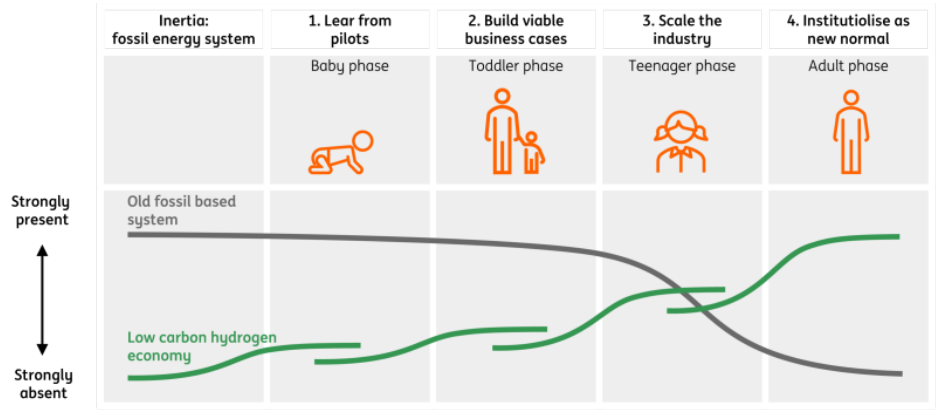
So what will 2026 look like? Here are our top 3 calls.

Call 1: Hydrogen stuck in the pilot phase

Low-carbon hydrogen – either from gas with CCS (blue hydrogen) or from electrolysers with renewable energy (green hydrogen) - continues to hold significant potential for decarbonising high-emission sectors such as steel, plastics, fertilisers, and fuel production for aeroplanes, ships, and trucks. From a chemical standpoint, these applications are feasible, and prominent advisors like Mario Draghi consistently highlight hydrogen's key role in helping industries reduce their reliance on fossil fuels, and for Europe to become less dependent on energy imports. Nevertheless, the poor economics and transformative changes required – particularly for existing industrial plants – present significant challenges. This underscores that establishing hydrogen as a mainstream commodity is a complex, multi-stage process that will unfold over several decades.

Building a low-carbon hydrogen economy is a multi-stage process

Phases of system change



Source: ING Research based on Transmission

The hydrogen industry's journey mirrors the stages of childhood. In the 'baby phase', the focus is on **learning from pilot projects** – testing out carbon capture in blue hydrogen, running green hydrogen electrolysers flexibly with renewables, exploring nuclear-powered electrolysers (pink hydrogen), and extracting white hydrogen from underground. It's also about building electrolysers that use fewer rare metals. The goal at this stage is to figure out what works technically.

Next comes the 'toddler phase,' where hydrogen must prove itself as a **viable business**, requiring solid financial returns for first commercial-scale plants, often with substantial financial support. However, the volume of low-carbon hydrogen produced remains small – insufficient to replace current usage of grey hydrogen.

With established technology and economics, hydrogen enters the 'teenager phase,' **scaling up** production and building infrastructure to reach more industries and regions. Only then can hydrogen start to substitute fossil fuels, potentially facing pushback from fossil fuel interests.

Finally, in the 'mature phase,'– if cost problems and anti-lobbying forces are overcome, hydrogen could become **mainstream**, supported by robust regulations and infrastructure. The focus shifts to phasing out old fossil fuel practices, managing workforce transitions, and supporting affected communities.

Although many hydrogen advocates thought the industry was advancing commercially, it has largely reverted to the pilot phase, especially for green hydrogen. There are about 1,700 clean hydrogen projects on the drawing boards globally, and moving these towards final investment decisions (FID) should be the focus for 2026 and beyond. Grants and subsidies are crucial for both innovative and large-scale projects, as is strong demand for low-carbon hydrogen. Streamlined permitting and planning are essential, and overly strict regulations on early projects – for example on the carbon intensity of low carbon hydrogen - should be avoided, as higher standards are more appropriate when the sector matures. To use the earlier analogy: expecting a baby to clean up its own mess is unrealistic; that will come in the 'toddler and teenage phases'. Finally, it is also crucial to shield the emerging industry from unfair foreign competition – just as we ensure our children's safety in nursery.

Call 2: The sector remains subdued due to the high cost and low off-take

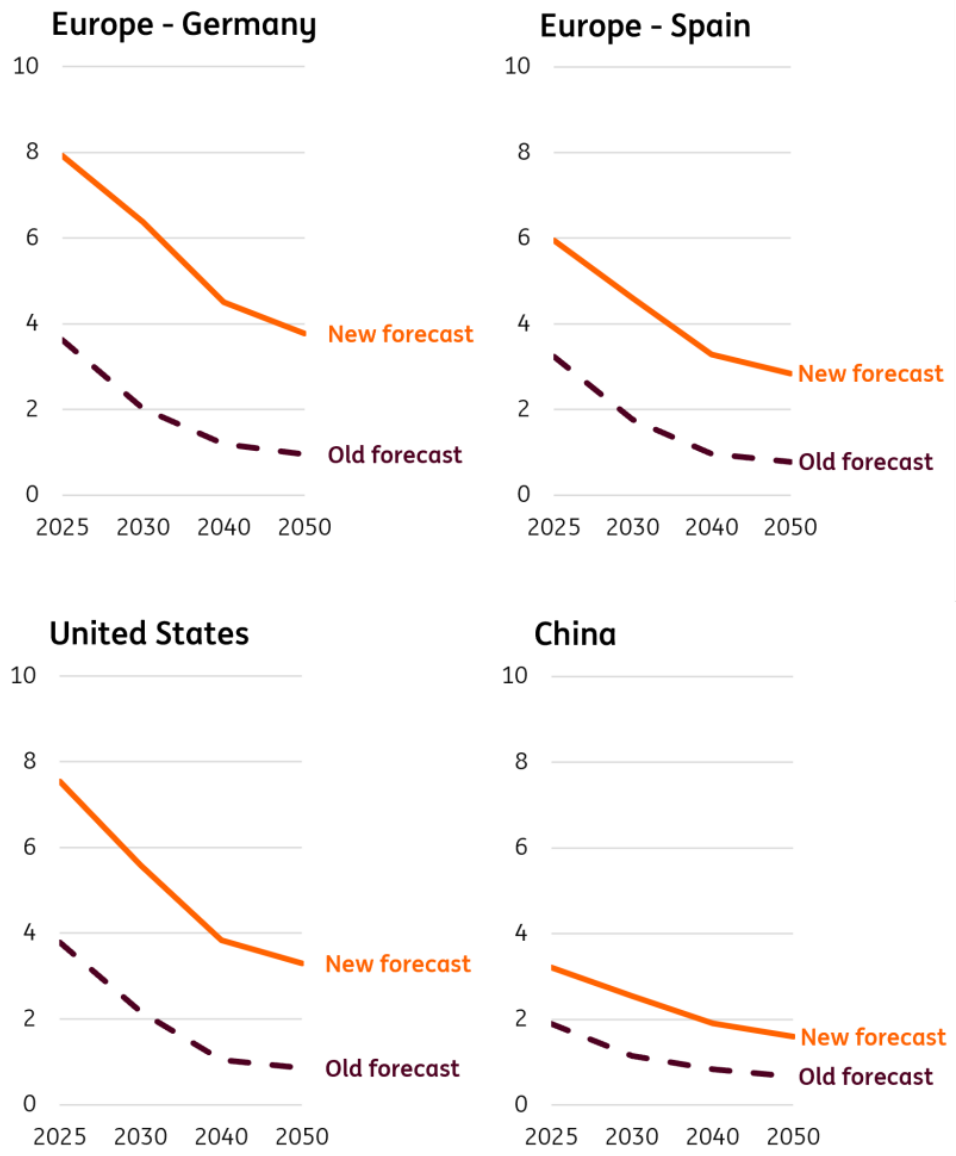
The clean hydrogen sector remains subdued in 2026. While global production is expected to double to 1.8 million tons per annum (mtpa) due to projects under construction coming online, this volume is less than 2% of current global (non-clean) hydrogen use. Production is expected to rise to 5.5 mtpa by 2030, according to

Bloomberg New Energy Finance, significantly short of the 25 mtpa combined targets from national governments across the globe. These targets are ripe for a reset based on market realism, but they might remain in place in 2026 as it is still a long way from 2030, at least in political terms.

Executives in the industry rank costs and weak demand as the main bottlenecks for viable business cases. Costs for green hydrogen production have been revised upward, notably due to higher energy, labour, material and trade costs and don't make up for the oversupply in the Chinese equipment market.

Green hydrogen costs are expected to be higher for longer

Comparing BNEF's 2023 forecast with its current forecast for the levelised cost of on-site production of green hydrogen in $/kg



Source: ING Research based on Bloomberg New Energy Finance

Due to persistent high costs, the industry requires vast amounts of government support throughout the full supply chain; from hydrogen production, transportation to hydrogen use; every link requires assistance. Governments across the globe allocated $222 billion for blue and green H_2 in 2025, which was down 20% mostly due to cuts in the US.

The **EU** and its members offer the most support – $123 billion across EU pots such as the EU Innovation Fund and Next Generation EU Funds, and state support via programmes such as the Important Projects of Common European Interest (IPCEI).

In the **US**, the One Big Beautiful Bill Act (OBBBA) reshaped the industry. It erased uncertainty around the 45V tax credit but moved the start-of-construction deadline forward to end-2027, squeezing green hydrogen developers. Some will speed up to meet the deadline, while others are likely to give up. Large scale electrolyser projects are particularly at risk as they struggle to secure big off-take agreements faster. Meanwhile, the 45Q credit for CO_2 capture has strengthened the business case for blue hydrogen, allowing it to take the lead. By 2030, over 90% of clean hydrogen is expected to be blue. Overall, funding for clean hydrogen was reduced from $90 billion to $28 billion.

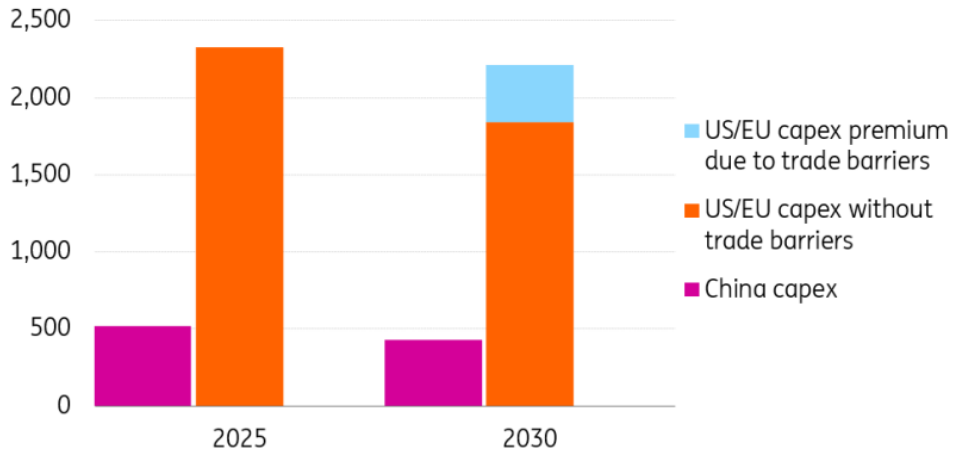
Demand remains severely underfunded - just 3% of the total support available is directed towards creating hydrogen demand. This compounds imbalances in the market: most proposed clean hydrogen suppliers have yet to find a buyer. Incentives to raise demand such as the Renewable Energy Directive (RED III quotas in Europe) have been watered down and regulation to green global shipping has been postponed (the proposals from the International Marine Organisation). Most binding off-take contracts so far have been driven by voluntary corporate decarbonisation goals in niche markets where few clients are willing to bridge the price gap by paying a green premium.

Call 3: China is likely to showcase a playbook for industry-wide adoption

Amid a green hydrogen backlash in the US, and Europe's ongoing challenges to stimulate hydrogen demand, global attention is shifting to China. In late 2025, hydrogen advanced from a niche pilot project to a central strategic priority within China's 15th Five-Year Plan (2026–2030). Building on its proven track record in rapidly scaling solar, wind, and electric vehicle sectors, China is positioned to take an assertive approach to developing and expanding its hydrogen industry. This strategy could fundamentally alter global cost dynamics for hydrogen equipment, as Chinese electrolysers are currently priced at just a quarter of those in the US and Europe. However, trade restrictions limit future cost reductions for European and American markets.

Chinese electrolysers are significantly cheaper, but ongoing trade restrictions limit further cost reductions for American and European electrolysers

Capex cost of electrolysers in $ per 0.2 cubic meters of hourly hydrogen yield



Source: ING Research based on Bloomberg New Energy Finance

The National Energy Administration in China has outlined four foundational pillars for this effort: robust policy support, technological innovation, enhanced project governance, and expanded international trade. On the policy front, a new capex subsidy scheme now covers up to 20% of project investment for green hydrogen, e-fuels, CCUS,

and related infrastructure. This measure is intended to reduce renewable power curtailment and help China achieve its emissions targets.

Regional governments have interpreted these national signals as a call to action. Provinces like Inner Mongolia, Hebei, and Shandong are accelerating large-scale electrolyser deployments and hydrogen pipeline construction, leveraging their abundant renewable resources and proximity to major industrial hubs.

Ultimately, China intends to transform hydrogen into a major new industry, potentially demonstrating a scalable blueprint for the rest of the world. Nonetheless, the sector will likely face familiar hurdles, including the gap between manufacturing capacity and end-use demand, as well as infrastructure challenges connecting supply and demand regions. It will be fascinating to observe how China addresses these challenges and what valuable lessons Europe and the US can glean from China as they work to develop a comprehensive hydrogen supply chain—including production, transportation, and utilisation in hard-to-abate industries.

Despite the tough environment for the industry overall, 2026 promises to be a dynamic year, with significant trends to watch.

.

European utilities: Steady currents

For the European utilities sector, trends observed in 2025 are continuing into 2026. For integrated utilities, cash flow generation is set to stabilise. For pure network operators, remuneration continues to grow with regulated asset bases that are expanding. Investments should rise by 6% on average for the sector, but with disparities among players

Nadège Tillier
Head of Corporate Sector Strategy
nadege.tillier@ing.com

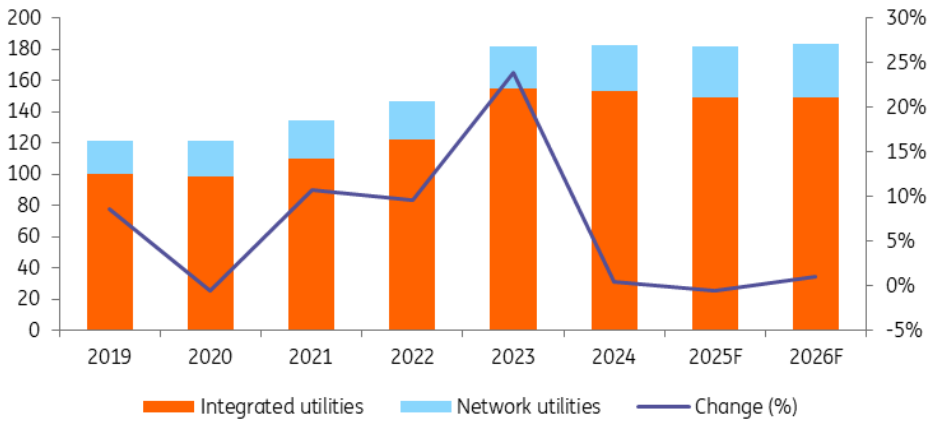
In Europe, more than 80% of the electricity volume sales are hedged a year in advance.

Call 1: The sector's cash flow generation stabilises

With the top 40 European utilities expected to generate around €186bn of EBITDA in 2026, the sector is projected to achieve 1% year-on-year growth. This growth will mostly be driven by pure network utilities, which should see their EBITDA grow by a robust 6%. Gas and electricity grid utilities should continue to benefit from a growing regulated asset base fuelled by ongoing investments to modernise, transform and expand the networks.

Modest cash flow generation growth in 2026

Top 40 European utilities aggregated EBITDA (in €bn)



Source: Company data, ING estimates

The modest growth in EBITDA for the sector on aggregate conceals significant disparities within sub-segments as well as players. The most diversified utilities, both from a business and a geographical perspective, will continue to fare the best, benefiting from continued rapid growth in certain parts of the globe.

In Europe, more than 80% of the electricity sales volumes are hedged a year in advance. As a result, the sector's cash flow generation from power production and marketing activities in 2026 will largely depend on the prices secured in 2025. With renewables representing a larger share, weather conditions to produce hydro, solar and wind power also play a big role in volumes and remuneration. In 2025, the price for the one-year forward contract for France, Germany, Italy, the Netherlands, Spain and the Nordic market averaged €74/MWh. Italy maintains the highest power price with the 1Y forward contract averaging €104/MWh in 2025, while the Nordic market pre-sold electricity at €36/MWh. For 2026, pre-sold electricity volumes will still be 1.3x to 1.4x higher than the pre-Covid era but around 5% lower than a year ago. Further price decreases should be seen in 2027 with forward contracts locked in during 2026 fully reflecting weaker gas prices. Additional capacity in renewables will also keep pressure on prices.

Call 2: Investments expand but at a slower pace

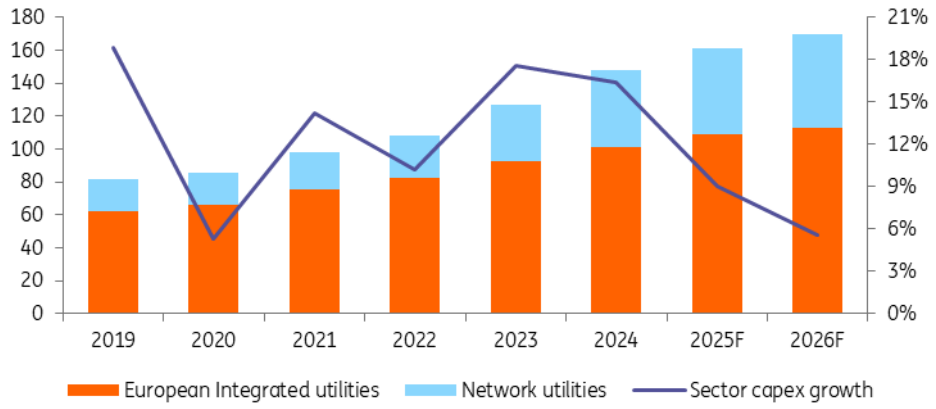
The sector's investment activity remains robust, but growth is slowing as integrated utilities become more selective in their project pipelines, especially in renewables. The top 40 European utilities will likely invest about €173bn in 2026, a 6% increase compared with 2025.

+6% growth in investments in 2026

Investment plans of integrated utilities point to €114bn of spending on infrastructure and projects in 2026, representing 4% growth vs. 2025. Yet disparities exist among European integrated utilities. For instance, EDF SA, Enel SpA, E.ON and EnBW remain committed to strong capital expenditure increases to build renewable projects and infrastructure, in the case of EDF, nuclear power plants. Other utilities such as EDP, Orsted and Naturgy are expected to see investment levels decline slightly or remain broadly unchanged from 2025 due to a more selective project strategy. The rise of material prices and operating costs has eroded margins and utilities are now more inclined to select the projects offering the best returns.

Capital expenditure is still on the rise, although at a lower pace

Top 40 European utilities' capital expenditure (in €bn)



Source: Company data, ING estimates

For pure network utilities, the requirement to expand and modernise grids and gas pipelines should result in an additional 12% increase in capital expenditure in 2026, bringing total investment for the top 20 operators to around €59bn. While German and Dutch Transmission (TSOs) and distribution (DSOs) system operators proportionally have the largest investment programmes, several network utilities have announced new increases. French TSO, Réseau des Transport d' Electricité will increase investments significantly. Between 2025 and 2040, investment needs are now estimated at €100bn. In Italy, Terna announced an ambitious investment programme to accommodate new renewables and interconnections while Snam will invest in renewable gases and new infrastructure. The same is true for Belgian TSOs. In the Nordics, the push for electrification and on/offshore wind integration obliges players such as Fingrid and Statnett to increase capital expenditure as well.

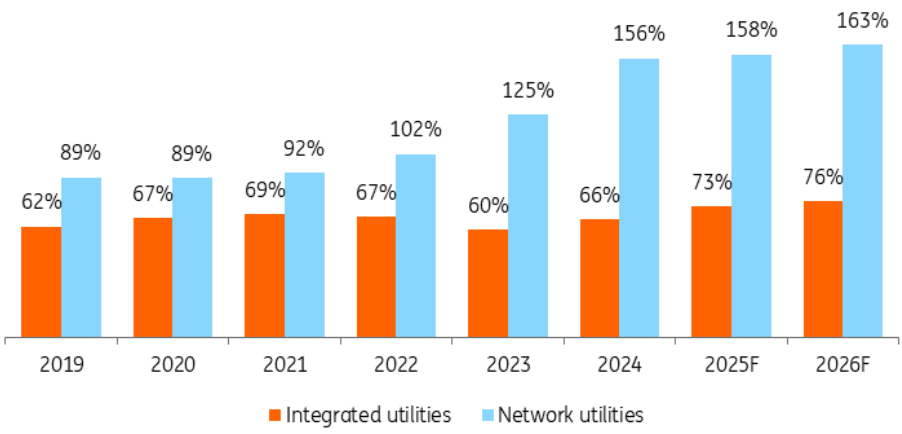
Inflation and the energy crisis in 2021 and 2022 impacted transmission and distribution network utilities, resulting in higher operating costs and materials. Some European regulators have already adapted their regulatory frameworks to allow TSOs and DSOs to recoup these past costs. The sub-sector's large investment needs have also driven these changes. In the Netherlands, 2026 is the final year of the current regulatory framework, which has seen a change of methodology to take operating costs into consideration. The Dutch regulatory body, the ACM, is now contemplating a cost-plus methodology for the next regulatory period. Germany is also working on the introduction of a cost-plus system, while it has already existed in Belgium for a long period of time. The methodology is now considered as the most appropriate in an environment of long-term investments as it takes into consideration the variation in inflation, operating costs, funding costs and other capital market elements, ensuring utilities remain financially viable.

Call 3: Spiralling debt means network utilities have to tackle funding challenges

The elevated level of capex, particularly for network utilities, is a source of concern for companies' credit metrics and funding capacities. Integrated utilities have benefitted from large cash flow generation thanks to their diversified business model. Grid operators, due to their capped revenues, have seen investment needs reaching levels far above their self-financing capacities since 2022. The situation has kept deteriorating, and we expect network utilities' capital expenditure to represent 164% of their EBITDA on average in 2026.

For network utilities, cash flow generation is not sufficient to cover investment needs

European integrated and network utilities: evolution of the cap-to-EBITDA ratio over the years



Source: Company data, ING estimates

In 2023, utilities issued €68bn in bonds on the EUR market. In 2024, the amount reached €72bn. In 2025, EUR bond issuance decreased to €62bn. Several utilities have looked for alternative funding solutions other than bank loans and bonds. Dutch utilities have already received shareholder loans and TenneT has had a total of €23bn in loans available to finance the capital expenditure. Future TenneT Netherlands' senior bonds will benefit from the Dutch state's guarantee and allow issuance at lower yields. TenneT Germany will receive c.€9bn from its new shareholders. With the deal between RWE and Apollo asset management, Amprion will benefit from additional funding resources that should reassure credit investors. The Belgian electricity and gas distribution utility Fluvius plans to receive €600m from its shareholders in the first half of 2026.

European regulated network utilities will need to continue looking for external funding to keep credit metrics and ratings at acceptable levels. Access to funds will become a major element in the determination of their credit ratings as signalled by rating agencies' methodology focus. In 2026, we expect utilities to issue around €70bn in EUR, supported by still growing investments, high bond refinancing needs and more Reverse Yankees. American utilities have also entered a strong investment growth period with capital expenditure growing 10-15% and issuing in the EUR currency allows them to benefit from lower rates in the current market conditions.

All in all, the European utilities sector should not surprise in 2026, with continuing trends such as moderate earnings growth. Elevated investment needs, in particular for the expansion of the infrastructure, will push network utilities to find diversified sources of financing.

* top 40 European utilities - integrated utilities (Acea, A2A, EDF, EDP, EnBW, Enel, Engie, E.ON, Fortum, Hera, Iberdrola, Naturgy, Orsted, RWE, Suez, Vattenfall, Verbund, Statkraft, Veolia, Centrica). Network utilities (Alliander, Elia, Enagas, Enexis, Eurogrid, Fingrid, Fluvius, Italgas, National Grid, Nederlandse Gasunie, Redeia, RTE, Snam, Statnett, Stedin, TenneT, Terna, Amprion, Ren, Redexis)

Disclaimer