Energy Outlook 2025: Growth amid challenges

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As we look ahead to 2025, the energy sector is poised for both growth and significant challenges.

Fossil Fuels: Despite the ongoing energy transition, fossil fuels remain dominant. The oil market appears stable, with prices expected to edge lower. However, geopolitical tensions and sanctions pose risks to this outlook. We expect weakness in European gas despite the stoppage of Russian pipeline flows through Ukraine. Meanwhile, the European carbon market is set for moderate gains.

Renewables: The renewable energy sector continues its upward trajectory in 2025. To support this growth, enhancements in transmission capacity, grid flexibility, and streamlined permitting processes are crucial. However, trade-protection measures may cause supply chain disruptions and necessitate the re-routing of critical parts, thereby increasing costs for developers in the US and Europe.

Carbon Capture and Storage (CCS): We anticipate solid progress in CCS infrastructure and growing demand. However, most capacity additions will occur post-2025, as CCS development is a long-term endeavour.

Hydrogen: The hydrogen hype of 2024 has given way to a more realistic outlook for 2025. The focus is shifting from ambitious project announcements to tangible execution and progress. Despite this, our forecasts still fall short of policy goals.

European Utilities: Leading the energy transition, European utilities are set to invest approximately €160 billion to shift electricity generation from fossil fuels to renewables. This transformation requires modernising and expanding the grid. While the sector's cash flow remains robust, significant bond issuance will be necessary to finance these investments.

Oil, Gas & CO_2: Comfortable energy fundamentals vs growing supply risks

The 2025 oil balance looks comfortable which should see prices edge lower. However, sanctions are a clear risk to this view. We also expect weakness in European gas despite the stoppage of Russian pipeline flows through Ukraine. For European carbon, we believe the market is set for some moderate gains.

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Call 1: Oil market to be in surplus but growing supply risks

Oil prices have had a strong start to the year on the back of stricter US sanctions against the Russian energy sector and colder weather supporting demand in parts of the Northern Hemisphere. In addition, the decision from members of OPEC+ to extend additional voluntary cuts has reduced the scale of the surplus that was initially expected for 2025.

The oil market is still set for a 500k b/d surplus, which should keep a cap on prices. However, the uncertainty over Russian supply means that prices are likely to be better supported than initially expected. We expect ICE Brent to average US$74/bbl in 2025, down from an average of US$80/bbl in 2024.

In terms of supply for 2025, non-OPEC output is expected to grow by around 1.4m b/d. This supply growth continues to be a problem facing OPEC+, making it difficult for the group to increase their own supply without accepting lower prices. OPEC+ are currently set to start unwinding their additional voluntary cuts of 2.2m b/d from April. The group will also unwind these cuts at a slower pace than originally planned. Instead of bringing this supply back over the course of 12 months, they will now do so over an 18-month period.

OPEC+ supply is a risk to our view. Already the group has delayed its easing several times. Pushing back the return of this supply even further would tighten up our 2025 supply/demand balance. However, the potential impact of stricter sanctions against Russia and Iran does provide other OPEC+ members the opportunity to increase supply without weighing too much on prices.

OPEC's spare capacity provides comfort to the market in the event of any significant supply disruptions

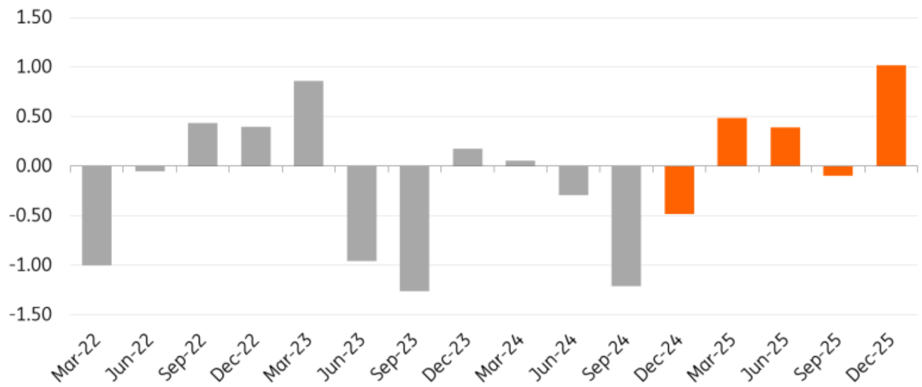
It is still too early to have a strong view of the potential Russian supply loss from US sanctions targeting Russia's shadow tanker fleet. But clearly, the uncertainty will support oil prices in the short term. These sanctions may disrupt flows in the short term; however, Russia and buyers will likely find ways to circumvent them in the medium to long run. Failing to circumvent them and assuming strict enforcement means that the global supply surplus we expect could be fully erased.

Iran is the other upside risk. It is unclear how aggressive President Trump will be with Iran, but stricter enforcement of US sanctions against Iran could mean a large decline in export supply. Under Biden, Iranian supply grew by a little more than 1m b/d. But again, losing Iranian supply would provide OPEC+ the opportunity to increase supply.

The cap for the market is the fact that OPEC+ is sitting on more than 5m b/d of spare production capacity. While the group may hold out for higher prices before tapping significantly into this, this spare capacity does provide comfort to the market if there were to be any significant supply disruptions.

Global oil demand disappointed last year with Chinese demand falling short of initial expectations. For 2025, demand growth is expected to be fairly similar to last year with global demand set to grow by around 1m b/d. Non-OECD, and specifically Asia, is set to dominate growth. Asia (including China) is set to make up around 60% of global oil demand growth. However, escalating trade tensions are not only a risk to oil demand but also broader sentiment across risk assets, something oil is unlikely to be able to escape.

Oil market set for a surplus, but sanctions are a clear risk (m b/d)



Source: NG Research, IEA, EIA, OPEC

Call 2: European gas to trade lower

European natural gas prices have been well supported through the 2024/25 winter. Firstly, stronger gas demand from the power generation sector towards the end of last year meant that European gas storage started the heating season below initial expectations. In addition, the region has experienced a more normal winter relative to the two previous winters which has supported heating demand.

This stronger demand comes at a time when Russian pipeline flows via Ukraine have been halted following the expiry of Gazprom's transit deal with Ukraine at the end of 2024. However, this stoppage was largely expected. The loss of this supply equates to around 15 bcm of natural gas per year. It also leaves the TurkStream pipeline as the only route for Russian pipeline gas into Europe, which in 2024 supplied a little under 15 bcm to the EU.

Stronger demand and reduced Russian flows have meant that Europe is drawing storage at a quicker pace this winter. Storage is well below year-ago levels and also lower than the five-year average. However, we still expect storage to finish this heating season at just below 40% full, compared to 58% last year and the five-year average of around 45%. Clearly, this is going to be dependent on how the weather plays out for the remainder of this heating season.

It is also important to point out that comparing expected storage levels at the end of this heating season to last year and the five-year average is not entirely a fair reflection of how tight the market is. The impact from Covid-19 and the two mild winters seen in

2022/23 and 2023/4 mean that both the five-year average and last year's storage levels were unusually high.

Increased supply risks and the EU facing a bigger task in refilling storage mean that the downside in prices is likely less than we originally anticipated

However, the lower storage levels mean that Europe will face a bigger task in refilling storage over the summer months and hitting the European Commission's target of having storage 90% full by 1 November. Expectations of stronger summer demand for storage are reflected in the forward curve with summer 2025 prices trading at an unusual premium to 2025/26 winter prices. The spread between summer and winter prices leaves little incentive for players to refill storage, so there may be a need for member states to take action to ensure mandated storage targets are met.

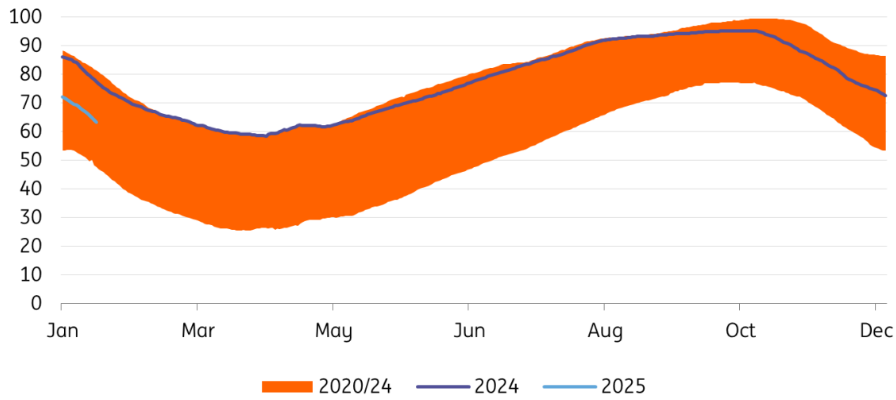
Recent moves in the JKM-TTF spread mean that Europe is pulling in additional LNG to ensure adequate supply. One factor helping Europe is weak Chinese demand so far this winter. Chinese buyers have reportedly been in the market to resell cargoes.

Furthermore, the global gas market will benefit from the ramping up of US LNG supply from Plaquemines LNG and Corpus Christi Stage 3. Once fully operational, this will bring in c.40bcm of additional LNG supply to the market. Unfortunately, the start of Golden Pass has been pushed into 2026.

There are clear risks facing the European market which leave it vulnerable. The global LNG surplus appears as though it has been delayed due to project delays. Meanwhile, the latest US sanctions against a couple of Russian LNG projects pose a risk to supply, although admittedly, these plants have relatively small capacity. The larger plants supplying Europe have not been sanctioned. Furthermore, there are reports that the EU is looking at a potential Russian LNG ban. However, this will have to be phased in given the disruptions it would cause if imposed in one go.

While we expect prices to trade lower through the year, increased supply risks and the EU facing a bigger task in refilling storage mean that the downside in prices is likely less than we originally anticipated. We expect TTF to average EUR36/MWh over 2025.

EU gas storage trending below 2024 levels & the five-year average (% full)



Source: GIE, ING Research

Call 3: EUA prices have bottomed

Having been under pressure for much of 2024 due to weak demand and stronger supply, EU Allowances (EUAs) have started 2025 on a strong footing with prices hitting their highest level since January 2024. Stronger gas prices, higher fossil fuel power generation and stronger heating demand have all been supportive for EUAs so far this year. In addition, speculators, who were bearish on EUAs for much of 2024, are now holding their largest net long positions since August 2022.

We expect higher EUA prices this year relative to last year. We forecast prices to average EUR75/t, up from an average of EUR67/t in 2024. Offering support to the market is the further removal of free allowances for the aviation sector, further shipping sector emissions covered, and the market preparing itself for the start of the removal of free allowances for Carbon Border Adjustment Mechanism (CBAM) sectors from 2026.

Demand is still clearly a concern, particularly once we get through the winter months. Industrial activity in Europe remains sluggish, while the potential for escalation in trade tensions is another concern.

This year the aviation sector loses further free allowances, which is part of the gradual phasing out of free allowances for the industry. Free allowances were reduced by 25% in 2024 and will be reduced by 50% in 2025 (from the initial free allocation). For 2026, there will be no more free allowances for the EU aviation sector. This should provide some support to demand. Looking further ahead there is also the potential that the Commission includes emissions for flights departing from an EU airport to non-EU destinations, rather than just intra-EU flights, as is currently the case.

While the bringing forward of EU supply has been a bearish factor, the fact that supply from 2027 has been reduced by a similar amount should prove supportive for prices in the longer term

Furthermore, 2025 will see more of the shipping sector's emissions covered. 2024 was the first year of inclusion of the shipping sector in the ETS and as part of a gradual phase-in, only 40% of the sector's emissions were covered in 2024. For 2025, this rises to 70% of the sector's total emissions. And from 2026, 100% of emissions will be covered. Again, this is broadly supportive of demand dynamics.

In addition, while we are currently in the transitional phase of CBAM, from 2026 it will be fully implemented, which will see CBAM sectors starting to gradually lose their free allowances.

The selling of allowances to fund REPowerEU added to the downward pressure on EUA prices for much of 2024. The European Commission wants to raise EUR20bn from allowance sales in order to partly fund REPowerEU. This supply has come from the Commission bringing forward volumes which were set to be auctioned later in the decade. In total, the plan is to bring forward 266.7m allowances for auction between 2023 and 2026. In 2023, 35.2m allowances were sold, while in 2024, 86.7m allowances were sold. This has raised EUR8.43bn for REPowerEU. The Commission still has almost 145m allowances to auction between now and the end of 2026 and given the target to raise EUR20bn in total, this means that on average they would need to achieve a price of EUR80/t. This suggests that the EU will either have to sell even more allowances to achieve its EUR20bn target for RepowerEU or lower its target. If it is the former, obviously that would only provide further headwinds to EUA prices.

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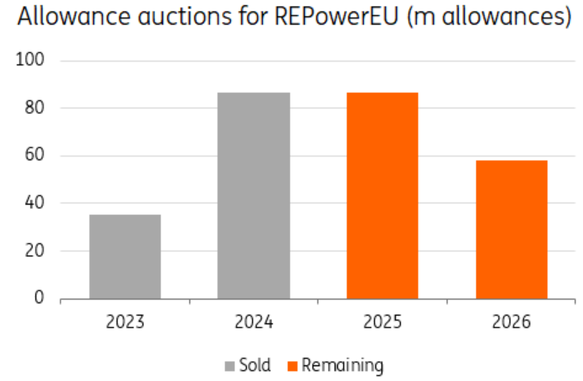
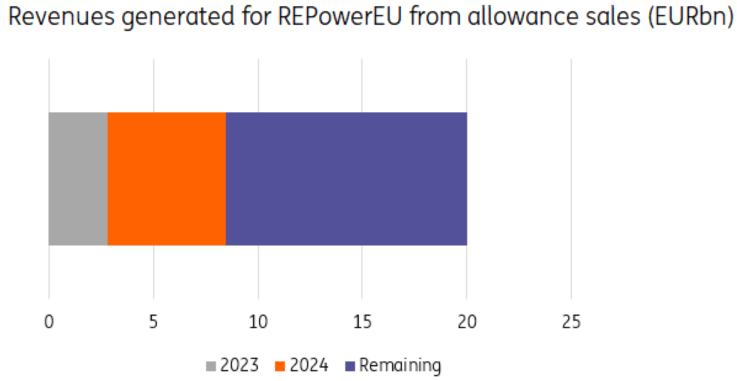
Allowance sales for REPowerEU adds to the pressure for EUAs





Source: EEX, EC, ING Research

ING forecasts

	1Q25	2Q25	3Q25	4Q25	FY25
ICE Brent (US$/bbl)	76	74	75	71	**74**
TTF (EUR/MWh)	40	35	32	35	**36**
EUA (EUR/t)	75	73	75	78	**75**

Source: ING Research

Renewable Power: Growth calls for system improvement

The demand for renewable power is set to climb, driving more project development, especially in solar. To ensure the grid is compatible with this growth, the EU and US need to boost transmission capacity, enhance grid flexibility, and cut permitting backlogs. Trade protection measures can lead to more re-routing and higher supply chain costs

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The demand for renewable electricity is expected to increase substantially in the future. In the US, corporate power purchasing power agreements (PPAs) are leading the growth, especially from data centres. The industry's rapid adoption of artificial intelligence (AI) is adding tremendous electricity demand, and purchases of solar and wind capacity by sustainability-conscious data centres increased to 34GW last year, contributing to half of all renewable capacity contracted to corporations. It is true that one executive order from Trump's inauguration calls for an end to the Biden administration's "EV mandate," but this would not materially affect short-term electricity demand growth as EV electricity consumption is only a fraction of the country's total now.

In the EU, the engine for renewable power demand growth has largely been the RePowerEU plan, with a mandate that 42.5% of the bloc's electricity needs will be drawn from renewables by 2030. This has led to more renewable auctions and power purchasing. Plus, the electrification-led energy transition across the transport, residential, and industrial sectors signals a structural change towards renewable energy power usage.

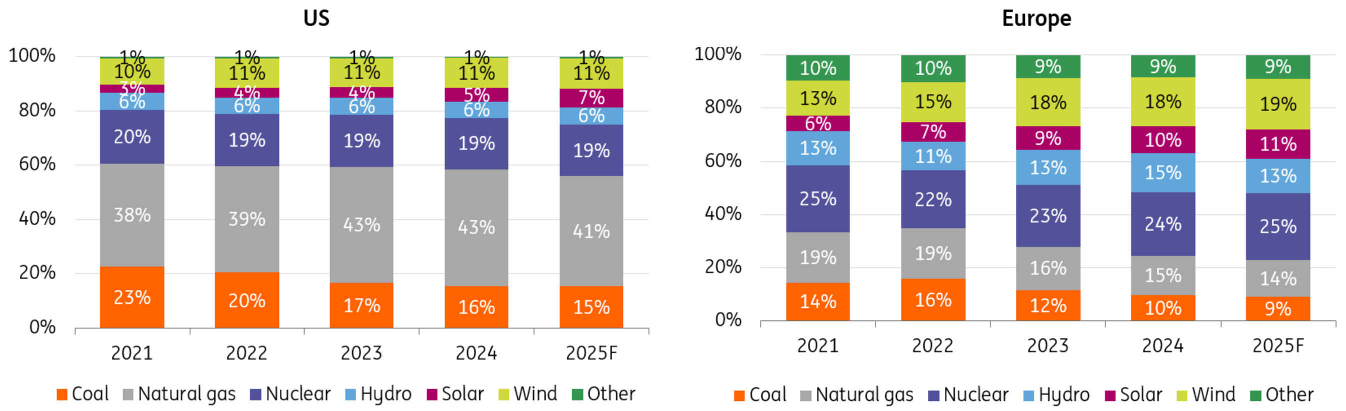
But will this jump in the need for renewable power be met? Which elements are driving – or complicating – the renewable power market? In this article, we focus on solar and wind power and identify three key trends for 2025.

But will this jump in the need for renewable power be met? Which elements are driving – or complicating – the renewable power market? In this article, we focus on solar and wind power and identify three key trends for 2025.

Call 1: More capacity in 2025 – but wind outlook varies by region

We expect renewed momentum for developers to continue their efforts to keep up with the demand increase in 2025. This is driven by competitive costs, sustained corporate renewable power purchasing, renewable auctions, and existing government funding. Capacity building will continue to translate into increased renewable power generation in 2025, as most projects that are well underway with secured grid connections are unlikely to see disruption. We foresee the share of solar and wind in the total power mix likely growing from 28% in 2024 to 30% in 2025 in the EU, and from 16% to 18% during the same period in the US.

Solar and wind's share in total power generation continues to climb in 2025



Source: ING Research, International Energy Agency, US Energy Information Administration, Eurelectric

However, it is worth noting that in the EU, renewable capacity and generation growth will likely come from both wind and solar sources, while the US market will be predominantly driven by solar.

In Europe, we anticipate that the upcoming Clean Industrial Deal will position renewables as a strategy for businesses to become greener and remain competitive by reducing power costs. This is achieved through Power Purchase Agreements (PPAs) from renewables, which offer lower power costs compared to market prices driven by gas-fired power plants that run on costly LNG.

In the US, policy disruption is already underway for the wind industry. As expected, offshore wind leasing has been temporarily paused. More surprising is the temporary pause on new and renewed approvals, permits, and loans for both onshore and offshore wind projects. While there are not yet overarching measures on existing permits, Trump's order does call for a review of wind permitting procedures in general. All this will deal a major blow to the wind industry, especially offshore wind, leading to a plunge in market confidence and slowed project development. We can expect legal challenges to this order; eventually, we could expect much stricter permitting criteria for new projects, with existing permits being assessed on a case-by-case basis. Solar has not been targeted so far, which was not surprising given a more systematically competitive cost profile and less perceived opposition. (We also hold a positive view on biofuels as it has been included in Trump's 'Unleashing American Energy' executive order to support domestic energy development. And we are cautiously positive about technology-neutral clean electricity tax credits under the Inflation Reduction Act, because of the potential benefit to more technologies including nuclear.)

Admittedly, the offshore wind industry has already faced challenges in both the US and Europe. In 2023, the industry was adversely impacted as the large-scale nature of projects and substantial capital investments collided with high inflation, rising interest rates, and supply chain disruptions. Macro conditions have since moderated, and auction re-designs are underway, but the sector’s recovery has been slow. In the US, notable project cancellations in 2024 included those from Ørsted, GE Vernova, Equinor, and BP. In the EU, Vattenfall exited an offshore bid after winning it, while a Denmark offshore tender in the North Sea received no bids. The offshore wind levelised cost of energy (LCOE) has fallen over the past few years but remains more elevated than onshore wind and solar.

However, we still see positive potential for offshore wind in the EU and this is largely driven by government policy support. Many countries, including Germany, the Netherlands and Denmark, will continue to have government support in terms of revenue contracts, grid connection, and tender issuing (there are examples of successful tenders too). We do not therefore foresee tenders becoming less attractive for developers in Europe. Instead, we expect developers to prioritise certain tenders over others and avoid submitting subsidy-free bids.

With the market dynamics presented above, we maintain a positive outlook for solar in 2025, with the wind market less complicated by policy in Europe.

Call 2: Expanding the focus from renewables buildout to grid enhancement

The climbing demand for renewable electricity is keeping developers busy building new plants. But there is a growing threat that grids in the EU and the US may not have enough capacity or flexibility to deliver all the renewable electricity while maintaining stability. Timely actions to improve the grid have therefore become important.

Firstly, more **transmission lines** are needed to send renewable electricity from generation sites, which are often in remote areas, to urban areas where demand is. This need has grabbed the attention of governments. In the US, the Infrastructure Law and Inflation Reduction Act (IRA) have allocated billions of dollars to expand the grid. In 2024, a cumulative 28,275 miles of transmission lines were under development/planning, visibly higher than previous averages. As for Trump, we think the new administration will be conscious of addressing grid insufficiency, leading to more power capacity to be connected to the grid, including solar and wind.

Across the Atlantic, the EU laid out an Action Plan in 2023 to facilitate new grid projects and enhance access to finance, among others. Admittedly, project developers can find it hard to claim funding as resources are dispersed across EU and state-level programmes. But more improvements in EU policy efficiency are anticipated as the bloc enters the implementation phase of the Draghi report.

Secondly, not only is expansion needed but the **existing grid** itself needs to be enhanced for higher **efficiency and flexibility**. Regarding transmission lines, hardware and software improvements can already increase transmission capacity, meanwhile allowing more accurate real-time monitoring and adjustments. Regarding grid flexibility, more efforts are being taken to better manage electricity demand, including peak demand shaving, virtual power plants, and so on. Another key method of enhancing grid flexibility is through energy storage (discussed in closer detail later). Italy is to become the first country among the EU and US to host energy storage auctions starting in 2025 to enhance the grid. This mechanism could potentially be replicated in other countries.

Finally, **permitting reform** is needed for approving grid-related projects to ensure the grid is improved at a speed matching that of renewable projects. In Germany, onshore wind projects still needed to wait for around two years to be connected to the grid after project approvals from 2018-2022, up from one year in 2011-2017. In response, Germany implemented an EU-enabled Emergency Regulation, which allows special measures to be taken if energy supply difficulties prevail. The country has since then experienced substantial grid project permitting growth, with an estimated 1,772 kilometres of new transmission lines approved by July 2024. Further implementation of the EU Renewable Energy Directive III's reform on permitting processes will also be helpful.

In short, we are seeing an expansion of focus from capacity buildouts to addressing systematic bottlenecks so that the renewable industry can continue growing to its full potential.

Increased focus on long-duration energy storage

Despite the massive scaling up of solar and wind, they still face a fundamental challenge: intermittency. Energy storage comes in as a critical solution. Existing technologies such as lithium-ion batteries provide short-duration storage solutions, but the dispatching time (less than four hours) is too short to be effective. That is why long-duration energy storage (LDES) – defined differently across countries but generally refers to technologies with over eight hours of dispatching time – is now gaining traction.

Among LDES technologies, only pumped storage hydropower (PSH, with 4-10 hours of dispatching time) is commercially available. The US currently has about 22GW of PSH capacity, while Europe hosts roughly 46GW, with more development underway in both places. But even PSH's dispatching length is still not high enough. Longer-duration storage technologies are emerging, including compressed air energy storage, liquid air energy storage, thermal heat storage, and aqueous electrolyte flow batteries. These technologies are still on the way to commercialisation, requiring significant policy and capital support.

A positive aspect to note here is that governments, developers, and investors are keen to get a head start in emerging LDES technologies, boosting demand and project pipelines. California Public Utilities Commission plans to take bids in 2026 to procure 2GW of LDES from 2031-2037. Germany is planning for a 500MW LDES tender for 2025 and 2026. Almost 6GW of capacity is likely to have been added in 2024; this trend is expected to continue in 2025 with stacking tender plans and planned projects.

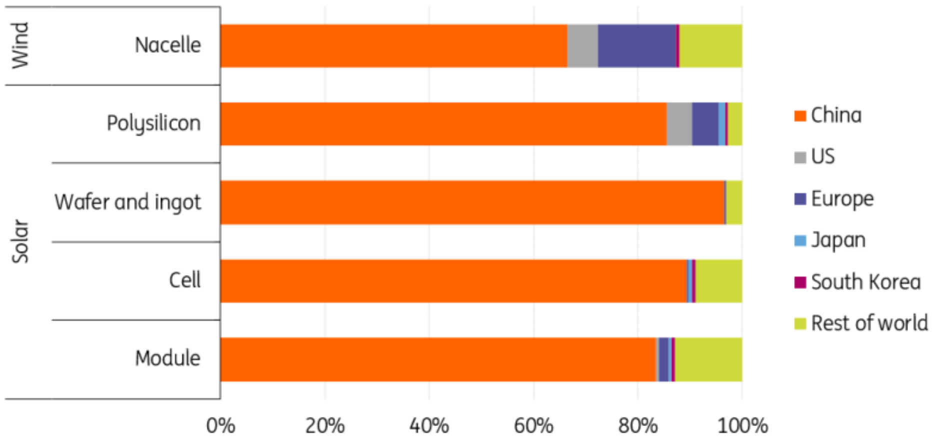
Call 3: Western protectionism and China's production overseas to shake up the market

Both the US and the EU are prioritising building the domestic renewable power supply chain. The EU has rolled out the Net-Zero Industry Act, forming industrial hubs and promoting a supportive regulatory environment for more investment in domestic manufacturing. In the US, the IRA and Infrastructure Law offers financial support for solar and wind manufacturing, and it is possible that the Trump administration may add more domestic content clauses, such as the requirement for a higher percentage of equipment parts to be produced in the US.

Still, the full impact of these policies is set to be felt in the long term. For now, China is maintaining its dominance in solar and wind manufacturing and it remains difficult for the EU and the US to shake off the China supply chain habit.

China's dominance in solar and wind manufacturing

Solar and wind production capacity by origin



Source: Bloomberg New Energy Finance, ING Research

Large production capacity in China has contributed to low costs and prices. For example, Chinese wind turbines offer a 32% price discount compared to their Western counterparts, and Chinese manufacturers are increasingly targeting Western markets due to fierce domestic competition. The situation is similar for other cleantech solutions, including solar panels. This has led to rising protectionism against China's dominance through trade policy.

In the US, former president Joe Biden continued the path forged by his two predecessors and raised tariffs on Chinese solar panel equipment to over 300%. US imports of Chinese solar equipment have consequently collapsed to almost zero, but the country has instead been importing from Southeast Asia, where China has ramped up manufacturing. This has prompted Biden to impose tariffs of up to 271% on solar imports from Vietnam, Thailand, Cambodia and Malaysia. With Trump's hawkish stance on China, we do not expect any easing of these tariffs; we may even see them being ramped up in the case of an exacerbated trade war.

These measures could lead China to re-route trades within Southeast Asia. Chinese solar companies were already building production capacity in countries such as Indonesia and Laos. Trade re-routes and lucrative tax credits from the IRA can be buffers to supply chain shocks in the US, but trade tensions can still result in higher equipment and project costs. Trump's proposed 60% tariff on all imported Chinese goods will further add complications to developers' access to low-cost materials.

Meanwhile, Chinese solar companies are looking to manufacturing in the US and bypass the tariffs. Among them, Chinese company Longi and US company Invenergy formed a joint venture (JV) to build a 5GW solar module factory in Ohio. While such projects can help the US build the domestic supply chain, they have also drawn security-related concerns. But we think the majority stake held by US counterparts in this type of JV – as well as the economic benefit brought to the industry – could give these projects a lifeline.

In Europe, there are currently no tariffs on imports of solar or wind equipment, though the EU has just finalised a tariff of up to 48% on Chinese EVs, and the bloc is also undergoing an investigation into any potential unfair government subsidies on Chinese wind turbines (the EU dropped investigations on Chinese companies' biddings of two solar tenders after they withdrew applications). In a more hawkish scenario, the EU might align with the US and start imposing tariffs on Chinese renewable equipment, most likely wind turbine parts. This would result in at least an initial shock among EU developers, as they remain highly dependent on direct Chinese exports. Chinese renewable power companies are also trying to open factories in Europe to avoid potential tariffs, and we foresee the country doubling down on this effort in 2025.

The need to match supply with mounting demand for renewable power has confirmed our view on another year of strong growth in solar and wind deployment in the US and the EU. It has also called the industry's attention to ensure the grid has enough capacity and is effective in bringing on more renewable electricity. For solar and wind capacity to grow resiliently in the future, transmission line efficiency, demand response, and power storage are all crucial. And as China continues to dominate the renewable manufacturing supply chain, it has grown increasingly important for other countries to implement competitive industrial policies that facilitate investment and innovation. Trade protectionism can shield domestic companies from foreign competition, but there can be a short-term cost to pay.

Carbon Capture and Storage: Gaining ground, despite challenges

Our top three predictions for carbon capture and storage in 2025 (CCS and CCUS): expect solid infrastructure progress and growing demand, but policy support needs clearer guidance from the US and a firm commitment from Europe.

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In 2024, carbon capture and storage (CCS) saw significant progress with increased policy support, streamlined permitting, and greater industry interest. Recognised for its role in achieving a net-zero economy, CCS conferences also attracted record attendance levels.

However, fewer projects reached final investment decisions (FID) than expected. Many early-stage projects lacked viable business cases and funding, while even advanced projects faced delays due to complex permitting and project-on-project risks (misalignment of different projects in the CCS supply chain where projects for capturing, transporting and storing CO_2 often involve different parties).

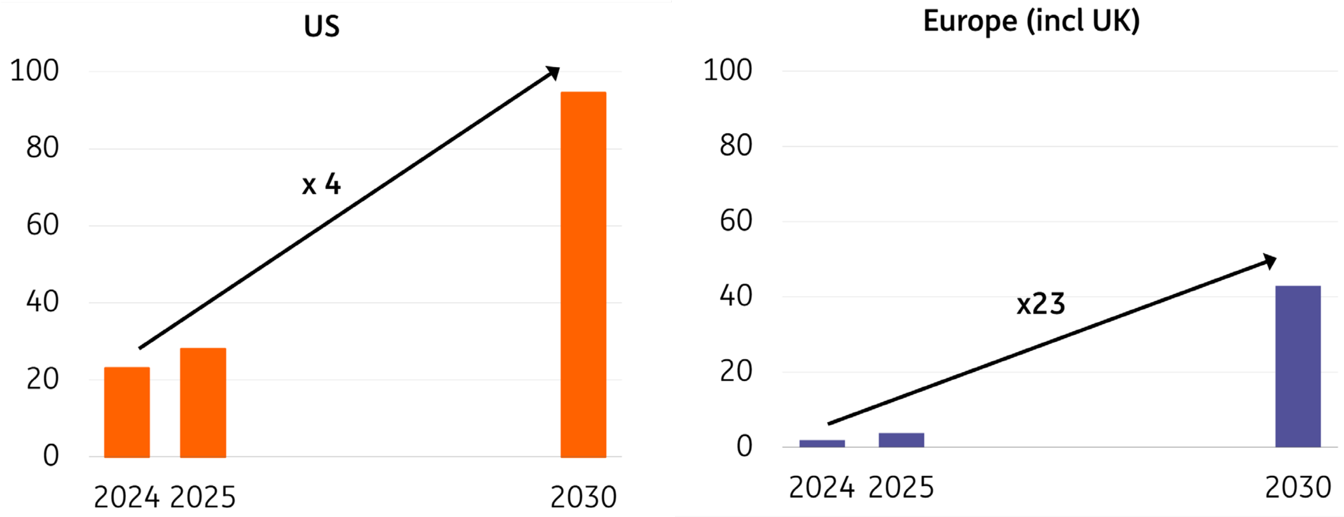
Looking ahead to 2025, we anticipate continued progress in CCS, despite policy uncertainty from Trump's second term, German elections, and the upcoming Clean Industrial Deal in Europe.

Call 1: Solid progress on infrastructure, but CCS development is a long road

There is a growing consensus that Carbon Capture and Storage (CCS) is essential for achieving a net-zero economy. According to the International Energy Agency, approximately 6,000 megatons of CO_2 need to be captured and stored annually by 2050 to meet the goals of the Paris Agreement. This target represents 16% of current global emissions, a stark contrast to the mere 25 megatons currently captured in the US and Europe.

Significant growth expected for CCS in the US and Europe, although it starts from a low base, with most expansion occurring after 2025

CCS capacity in million metric tons per year (megatons)



Source: ING Research, based on Bloomberg New Energy Finance, base case scenario.

US: the largest market

The US is expected to maintain its lead, with CCS potentially increasing fourfold by 2030. While many projects were announced following the Inflation Reduction Act, some developers adopted a wait-and-see approach before the elections, as CCS-support scheme details remained unsettled. Post-election uncertainty persists, with the Trump Administration likely to lower climate targets and environmental regulations, potentially deterring medium to smaller emitters from investing in CCS. However, larger emitters remain committed to sustainability, and the Trump Administration's pro-CCS stance, influenced by the oil and gas industry, supports the multi-billion-dollar CCS market. There is strong momentum for ethanol projects, with developers funding capital expenditures to capture CO_2 at $25-$30 per ton, and for transportation and storage at $25-$35 per ton, incentivised by an IRA tax credit of $85 per ton. However, permitting delays and local opposition (NIMBYism) continue to challenge these projects, with most growth expected after 2025.

Europe: catching up with CCS hubs along the North Sea

In Europe, including the UK, policy momentum for CCS is rising, with progress in creating carbon capture hubs in industrial clusters near the North Sea. Significant projects include Northern Lights (storing CO_2 from Norway, Denmark, Belgium, and the Netherlands in Norway), Porthos and Aramis in the Netherlands, the Northern Endurance Partnership (NEP in East Coast Cluster) and Hynet (Liverpool Bay) in the UK, and the pilot projects Greensand in Denmark and Ravenna in Italy. European capacity is projected to grow 23-fold by 2030, though from a much lower base compared to the US.

The long road to CCS development

The challenges of making CCS work encompass the entire supply chain.

First, CO_2 needs to be **captured**. Large emitters are hesitant to make final investment decisions for capture installations due to uncertainty and delays in CO_2 infrastructure (the chicken and egg debate). This is true even for emitters near planned CO_2 infrastructure in the Benelux, UK, and Norway. For many emitters in Eastern or Southern Europe, CO_2 transport and storage infrastructure won't be ready until at least 2035, excluding CCS options as a near-term solution altogether.

Second, CO_2 needs to be **transported**, preferably by pipelines for cost efficiency. The European Commission recently noted that Europe might need 19,000 km of CO_2 pipelines by 2050 to meet its net-zero ambition.

Countries take different approaches to regulating the CCS business. The UK tightly regulates this sector to prevent excessive profits from natural monopolies, similar to its regulation of power and gas grids. This results in low and regulated returns, which are unattractive to commercial market players like oil and gas majors who dominate the capture and storage part of the supply chain. Consequently, the development of CO_2 infrastructure is primarily left to grid operators.

In contrast, countries like Denmark, the Netherlands, and Belgium aim to involve more commercial parties, such as oil majors and institutional investors. As a result, the business is less regulated compared to the UK. These commercial parties typically prefer to oversize initial pipelines to allow for future scaling. However, the initial financial risk is high due to limited committed volumes of CO_2, making it challenging to reach final investment decisions (FID).

The Netherlands exemplifies this issue, as the Dutch government faces little interest from commercial investors to build CO_2 infrastructure, leaving the burden on state-owned grid operators like Gasunie and EBN, which require additional funding that the government is reluctant to provide. Yet the government heavily depends on a successful CCS rollout to meet its climate targets. The challenge is to turn this vicious circle into a virtuous one.

Finally, CO_2 needs to be **stored** but there's no uniform approach to doing this. Different countries and states have varying preferences for offshore and onshore storage, differing permitting procedures, and distinct liability frameworks in case of issues. These variations complicate the development of a global CO_2 market.

Addressing project-on-project risk through the alignment of projects across the entire CCS supply chain is crucial for robust CCS growth

Overall, the long-term CCS outlook is very positive but will take years to materialise. In 2025, progress should be measured by advancements in developing the full CCS supply chain and addressing its challenges with targeted policies, rather than by a strong increase in capacity number (the actual megatons captured and stored).

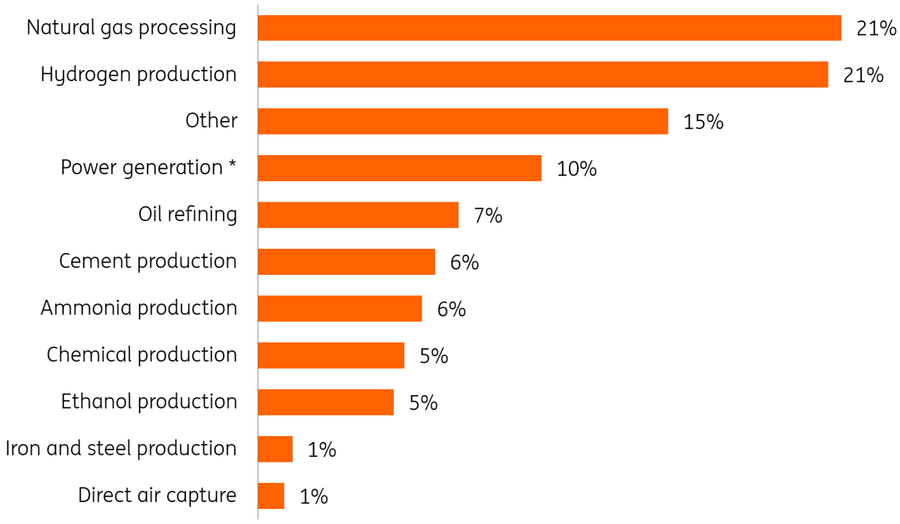
Call 2: Oil and gas industry dominates CCS demand

Most CCS projects globally are currently focused on enhanced oil and gas recovery, driven by favourable economics in the US and the existing expertise of oil and gas majors in deploying CO_2 capture technology. However, by 2030, CCS is expected to be increasingly utilised in (blue) hydrogen production and abated power generation. This includes installing capture systems, steam methane reformers on gas or coal-fired power plants, waste-to-energy plants, and biomass plants.

CCS is also being progressively applied in hard-to-abate sectors, particularly the cement industry, which faces significant challenges in reducing emissions without CCS. While various technologies can help the petrochemical industry and refineries to become greener, CCS remains the most cost-competitive option, further driving its adoption. In the steel industry, emissions can be significantly reduced with CCS, although the sector is increasingly focusing on electrification and hydrogen solutions, limiting the sector's contribution to CCS.

CCS find its way among a wide range of users

Anticipated share of CCS users globally by 2030



* Coal or gas fired power plants, waste to power plants, bioenergy plants with CCS called BECCS.

Source: ING Research based on Bloomberg New Energy Finance and Rystad

Storing CO_2 is the norm, utilising CO_2 the exception

The vast majority of captured CO_2 is permanently stored underground (CCS), with only 2% destined for utilisation (CCUS), such as in greenhouses to efficiently grow plants.

In the future, captured CO_2 can also be used to produce plastics or synthetic fuels for aeroplanes, ships, or trucks. While this won't become substantial before 2030, it has vast potential in a net-zero economy where carbon currently sourced from fossil fuels must be replaced by a combination of captured carbon, biogenic carbon, and recycled carbon. Although the CCS industry is often criticised for not providing a 'truly sustainable solution,' it holds the potential to become an important carbon source in a net-zero economy.

The future promises the utilisation of CO_2 rather than its permanent storage underground

And so is direct air capture

Almost all CO_2 is captured from chimneys on industrial sites (post-combustion or end-of-pipe CCS) or by separating CO_2 streams in chemical processes (pre-combustion CCS). Only a tiny fraction, less than 1%, is captured directly from the air using a technology called Direct Air Capture. Demand for this technology comes from major companies like Microsoft, Airbus, Amazon, and Google who are eagerly offsetting their carbon impact not just by planting trees, but by actively removing CO_2 from the atmosphere. However, the technology still has a long way to go before it is fully developed and economically scalable. Direct Air Capture is also very energy-intensive and must be fully powered by renewable energy. Otherwise, it risks adding more CO_2 to the atmosphere than it removes.

Call 3: Continued policy support, but room for improvement

Policy support for CCS is expected to remain strong on both sides of the Atlantic. In the US, the CCS market could benefit this year from clearer details and guidelines while Europe could benefit from a simpler commitment to CCS. However specific policy details need to be clarified for major players to make final investment decisions.

US: will Trump address the finer details?

The Internal Revenue Service (IRS) in the US has yet to release classifications and guidelines for 45Q, the relevant tax credit for CCS in the Inflation Reduction Act. Initially seen as a minor issue due to the strong support for CCS, it is now considered a critical detail.

Effective policy measures require addressing the finer points, a quality the Trump Administration will have to master. Crucial questions remain, such as the quality of Life Cycle Analyses required for CCS to qualify for 45Q credits, the types of storage sites that can be used, and what applications will count as CO_2 utilisation. A lack of action from the Trump administration could suppress the market, but a solution is expected given Trump's support for the oil and gas industry, which is committed to CCS and likely to lobby for clarity.

Similarly, support from the Department of Energy and the Office of Clean Energy Demonstrations is crucial for building regional Direct Air Capture Hubs, which major tech companies aim to use and advocate for to offset emissions.

Europe's CCS commitment could benefit from a clear message

Europe's commitment to CCS shows up in several directives.

In its **Industrial Carbon Management Strategy**, the European Commission laid out technology pathways for high-emitting sectors in which CCS plays a major role. This was followed in 2024 by the **Net Zero Industry Act**, which defined clear CCS goals for the European Union, including capturing and storing 50 million tons of CO_2 annually by 2030 and utilising an additional 10 million tons of CO_2.

In February, the European Commission will present a **Clean Industrial Deal** as Europe's answer to the IRA in the US, aiming to simultaneously lower emissions while remaining competitive in global markets. It is expected that CCS will feature prominently as it allows emitters to reduce emissions cost-effectively (CCS is relatively cheap compared to other carbon reduction strategies). It is also anticipated that the deal will stimulate member states to implement Carbon Contracts for Differences (CCfDs) that compensate emitters for the cost difference between the benefits of CCS (the EU carbon price) and the cost of applying CCS. Finally, the Clean Industrial Deal is expected to support cross-border carbon markets by alleviating trade restrictions on CO_2 and streamlining permitting processes.

While these initiatives are promising, Europe's commitment is somewhat obscured within these technical policy documents, which are not well-known by the general public. CCS could greatly benefit from a clear and straightforward policy commitment from the European Commission, and its major member states, as well as the UK and Norway, which are leading the CCS market.

Advances in policy support will be critical for CCS growth in this early market stage, and companies could lobby for it

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More progress expected

Overall, more progress on CCS policies is expected in 2025 on both sides of the Atlantic. The key challenge for companies is to mitigate risks within the CCS value chain. Large emitters face the risk of limited transport capacity, while transportation and storage providers risk having insufficient CO_2 captured. Stronger government involvement and coordination of final investment decisions among companies at the level of industrial clusters could help overcome these "chicken and egg" problems, boosting the CCS industry.

Hydrogen: Beyond the hype it is all about execution

Here are our top three calls for hydrogen. The sector is shifting from announcements to execution. The US leads with blue hydrogen, while Europe is focused on green hydrogen despite cost and trade challenges. Meanwhile, hydrogen demand is moving from steel to oil refining and transportation.

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Call 1: Beyond the hype it's all about execution

Last year, we anticipated that 2024 would serve as a reality check for the efforts to scale up hydrogen. But expectations have fallen even more than anticipated, with new project announcements down by over 80% globally and producers scaling back earlier commitments.

This reflects the typical hype cycle of new technologies: peak optimism for hydrogen in the run-up to 2023 followed by disillusionment in 2024.

Looking ahead to 2025, we expect more realism, though from a pessimistic perspective. The focus will shift to execution and tangible progress on projects and investments. Nevertheless, the low-carbon hydrogen market remains in its infancy. Much of the growth is likely to happen from 2028 onwards when many committed and advanced projects are likely to come online. That's why we're not solely focusing on 2025, but also looking ahead towards 2030.

Call 2: Progress in domestic market supply amid rising costs

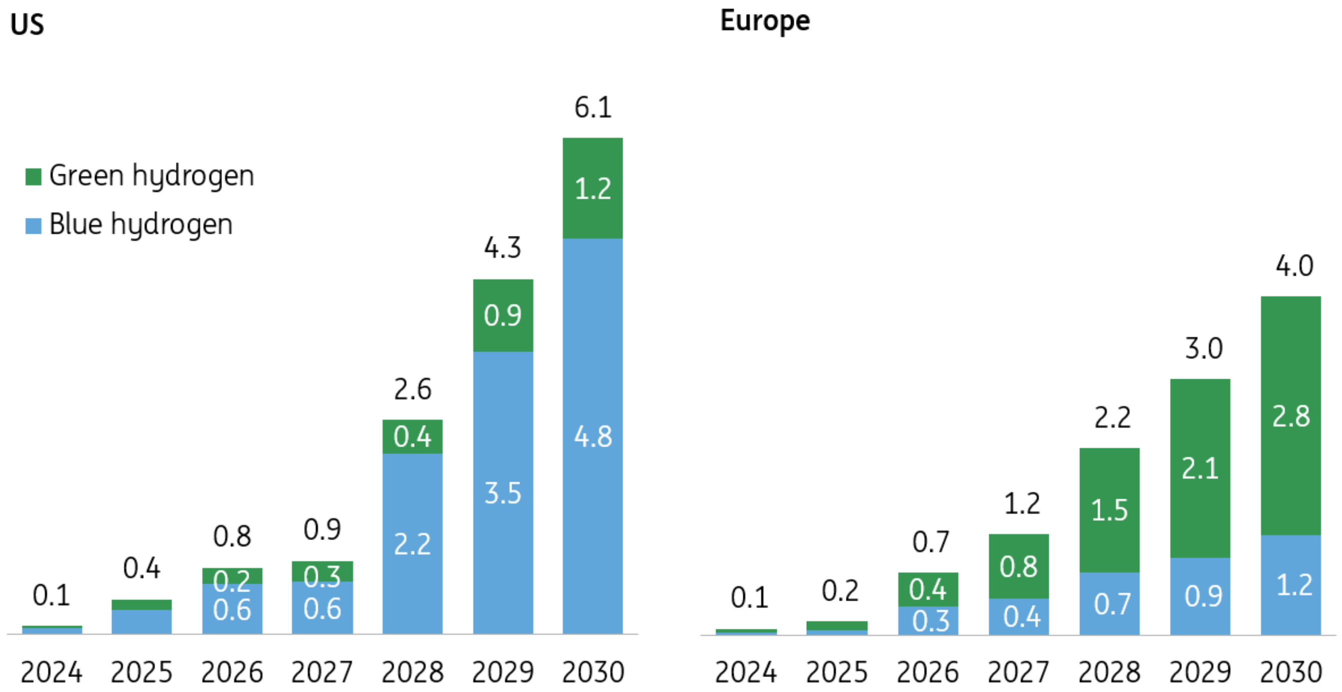
Government policies and targets will be the main drivers of blue and green hydrogen project development, with the US and Europe having the highest production potential thanks to strong policy support. Just over 60% of low-carbon hydrogen globally is expected to be produced in these regions by 2030, according to Bloomberg New Energy Finance.

The US hosts the most mature project pipeline globally and about 0.4 million tons of H2 is expected to come on line in 2025. The Donaldsonville hydrogen plant in Louisiana takes the lion's share with 0.3 million tons of blue hydrogen production. In addition, a couple of electrolyser projects are likely to come online and produce 0.1 million tons of green hydrogen in 2025. The size of current electrolysers ranges from 5 to 220 megawatts, meaning that green hydrogen projects are unable to match the scale of blue hydrogen plants.

The electrolyser pipeline in the US is small compared to Europe, which limits the deployment of green hydrogen. Furthermore, Trump is likely to favour natural gas production and Carbon Capture and Storage (CCS) over extensive support for expensive electrolysers. So blue hydrogen is likely to dominate green hydrogen, allowing the industry to grow more significantly due to the larger scale of blue hydrogen projects.

Strong long-term growth of low-carbon hydrogen in the US and Europe

Hydrogen production in million metric tons per year (megatons)



Source: ING Research based on Bloomberg New Energy Finance and Rystad

Europe, on the other hand, is focusing more on green hydrogen production by kickstarting electrolyser projects. Multiple projects are expected to come online in 2025, with Shell's 200-megawatt project in the Netherlands being the largest. A project from Air Liquide for blue hydrogen in France is expected to start production in 2025, but this project is relatively small compared to the Donaldsonville plant in the US.

Despite solid progress, the production of low-carbon hydrogen is projected to reach only four million tons by 2030, with green hydrogen contributing 2.8 million tons.

Government targets for low-carbon hydrogen are likely to be missed

This falls significantly short of the REPowerEU programme's target of nine million tons of green hydrogen production. While the market has achieved a level of realism, this has yet to happen for policy targets.

Supply side risks

The supply side outlook faces five main risks: funding, grid congestion, rising costs, a possible trade war and performance issues.

1) **Funding:** Most low-carbon hydrogen projects in the EU are funded by EU sources like the Projects of Common European Interest, the EU Innovation Fund, and the European Hydrogen Bank. The first auction by the European Hydrogen Bank showed that green hydrogen production costs are the lowest in Southern and Northern Europe (€5.8 to €8.8 per kg) and highest in Germany and France (€12 to €13 per kg). Despite subsidies averaging €0.46 per kg over 10 years, producers need a price premium of €3.3 to €6.5 per kg to break even, which is not yet secured by long-term contracts. In the US, besides private investors, the Department of Energy is providing loans and loan guarantees to clean energy projects including those of hydrogen. Plug Power, for example, received a $1.66bn conditional loan guarantee to produce clean hydrogen using electrolysers. However, the new administration brings

uncertainty to the loan programme. The challenge of securing offtakers has also led to funding difficulties.

2) **Grid Congestion:** Some projects struggle with securing grid connections or face future grid congestion. Reinforcing grids is complex, so enhancing the flexibility of electrolysers and green hydrogen production is crucial.

3) **Cost increases:** Rising material, labour and water costs are increasing project costs. Integrating electrolysers into the energy system is also more costly than anticipated, including higher grid and transportation costs. And these system costs are expected to remain high, with less optimistic long-term cost reductions. As a result, Bloomberg New Energy Finance recently raised its forecasts for green hydrogen production costs by +35%.

4) **Trade war and geopolitical tensions:** Currently, almost all installed electrolysers in the US and EU are Western-made. Cheaper Chinese electrolysers (50-60% less expensive) are tempting developers to import them to mitigate cost increases. However, this threatens the goal of building domestic electrolyser industries in Europe and the US. The introduction of import tariffs and ongoing geopolitical tensions create uncertainty around investment decisions in 2025 - not just for electrolysers, but possibly for the entire green hydrogen supply chain, including critical materials, solar panels, and wind turbines, all of which are dominated by China. Thus, the hydrogen industry faces significant policy and trade uncertainty in 2025.

5) **Performance issues:** In 2024, some completed hydrogen projects, particularly those involving electrolysers, faced significant performance issues.

There's less optimism on how quickly learning rates will reduce the production cost for green hydrogen

Both established companies and startups struggled, leading to disappointing hydrogen production and impacting project outcomes. Addressing these performance challenges is crucial for the sector to achieve solid progress in 2025.

Call 3: Lower demand expectations with a shift from steel to aviation and shipping

Demand is a key bottleneck

Demand is a significant bottleneck in scaling up low-carbon hydrogen. Hydrogen project developers have only managed to secure about 10% to 15% of planned output through binding offtake contracts, primarily due to the 'chicken and egg problem.' Early adopters are hesitant to commit to current high price premiums for 10 to 15 years, fearing a cost disadvantage compared to competitors who adopt a wait-and-see approach to benefit from future lower prices. Without binding targets, hydrogen users such as producers of ammonia (fertilisers), chemicals (plastics), and steel still have the luxury of waiting.

Shifting demand from steel to oil refining and transportation

The steel industry exemplifies this shift. In past years, steel has been a major driver of investment announcements, particularly through clean hydrogen projects. However, we now see steel producers reconsidering earlier commitments, especially in Europe where energy prices are high, policy focus is on costly green hydrogen, and there are concerns about the availability of high-grade iron ore pellets. These pellets, ideal for hydrogen-based steelmaking, currently constitute only 7% of the iron ore supply globally.

Binding targets can be an effective way to stimulate demand

Demand from oil refiners and producers of e-fuels is expected to rise in 2025. According to Rystad Energy, most of the investments by oil majors in hydrogen are directed at replacing grey hydrogen operations with blue and green hydrogen to reduce emissions from their refineries. Another key segment is transportation, where hydrogen-derived fuels such as ammonia, methanol and synthetic jet fuel, provide low-carbon solutions for aviation and shipping. Oil refineries in Europe are expected to secure more clean hydrogen to comply with the REFuelEU Aviation initiative, requiring EU airports to use at least 1.2% green hydrogen-based fuel by 2030. The shipping sector also aims to use 5-10% of alternative fuel globally by 2030, though this target is not binding and also includes non-hydrogen fuel.

Boosting demand with CCfDs and clearer green standards

The German government launched the EU's first Carbon Contracts for Difference (CCfD) auction in 2024. This benefits hydrogen in two ways. CCfDs subsidise both new installations and operational costs by covering the large difference between conventional and low-carbon production costs for a long period (15 years in Germany). Furthermore, lower-cost CCS solutions are excluded from the auction. A significant budget increase for 2025 auctions will support demand in Germany. Meanwhile, such initiatives could also inspire other countries to adopt similar measures, boosting hydrogen demand.

In 2025, we also expect progress on the definition of green industrial activities. Different sectors and regions have varying guidelines, making it difficult to standardise green credentials for commodities like steel, cement, plastics, and e-fuels. While hydrogen-based fuel can be blended with current fossil fuel, facilitating the integration of new technology into existing systems, this is less feasible for products like steel, cement, and plastics. For example, blending 5% hydrogen-based fuel with conventional fuel is straightforward, but it doesn't make sense to produce 5% of a toy's plastic parts from hydrogen-based plastic and the rest from fossil-based plastics. The solution lies in reaching a consensus on mass-balance methodologies, allowing sustainability goals to be met at the portfolio level rather than the product level.

2025: policy decisions make 2025 a pivotal year

Since low-carbon hydrogen remains more expensive than current fossil fuel-based practices, it won't be business as usual for corporations. Therefore, policy decisions in 2025 will be crucial.

The European Commission is set to present its Clean Industrial Deal in 2025. This initiative aims to address the challenges faced by hard-to-abate sectors such as steel, cement, plastic and aluminium as detailed in the Draghi report. Policy must strike a fine balance of increased competitiveness in global markets while stimulating these sectors to quickly transition towards a net zero economy.

In the US, 2025 will reveal the full impact of policy risks, but hydrogen remains a viable market, despite developing at a slower pace than many have hoped. Under the new administration, we are confident that the hydrogen and CCS tax credits can survive and continue to play a crucial role in reducing costs, and there will likely be loosened eligibility criteria in claiming the credits. Nevertheless, any uncertainty around tax credit guideline finalisation, non-credit funding, and government-enabled hydrogen development programmes can slow down project development.

Therefore, 2025 will be a pivotal year, with significant developments and decisions shaping the future of low-carbon hydrogen.

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European Utilities: Big investments and bigger debt

At the forefront of the energy transition, European utilities will invest c.€160bn to shift their electricity generation from fossil fuels to renewable energies as grids need to be modernised and expanded.

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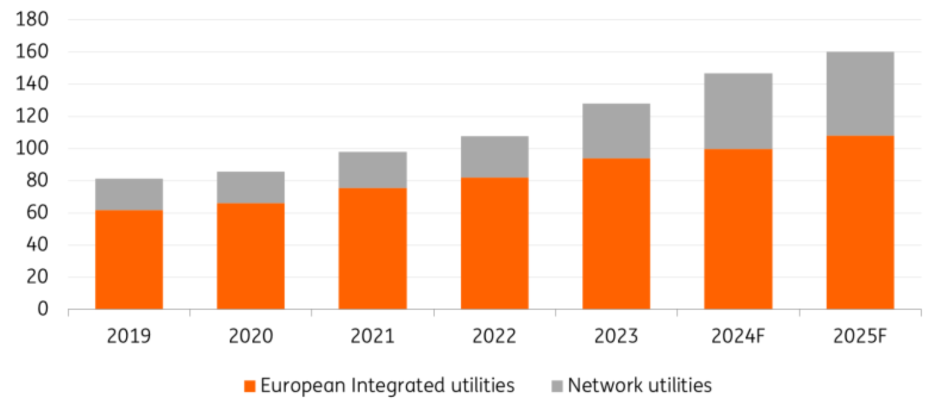
The European Union aims to cut net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels, and achieve climate neutrality by mid-century. To support this, the EU is focusing on renewable energy, energy efficiency, and the resilience of clean energy supply chains, including manufacturing and critical minerals. In June 2024, the European Commission adopted the Net Zero Industry Act to enhance clean technology manufacturing, aiming to meet 40% of the EU's deployment needs by 2030 and reduce dependency on energy.

Call 1: Capital expenditure guidance points to a 9% increase for the sector in 2025

According to their capital expenditure plan disclosures, the top 40 European utilities[1] will invest a total of €160bn in 2025, representing a 9% growth rate versus 2024. Between 2019 and 2025, the top 40 European utilities will have doubled their investments.

Investment has significantly grown 2019-25F (€bn)



Source: Company data, ING

European integrated utilities, whose activities stretch from grid operations, power generation, supply and customer services, show investment amounts that look very significant. Altogether the top 20 European utilities[2] will invest €108bn in 2025, an 8%

[1] Top 40 European utilities

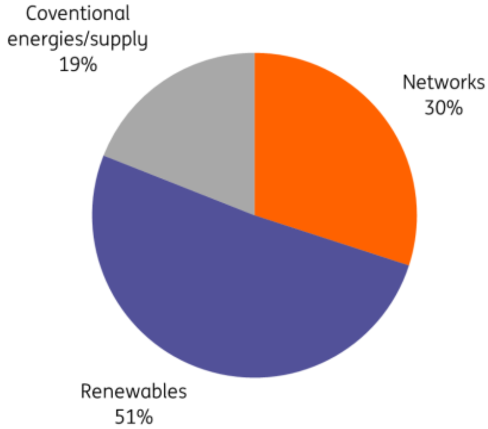
[2] Top 20 European integrated utilities: A2A, Acea, EnBW, Enel, Centrica, CEZ, EDF, Enel, Engie, E.ON, Fortum, Hera, Iberdrola, Orsted, RWE, Statkraft, Suez, Vattenfall, Veolia, Verbund

increase vs. 2024. These utilities are usually large-scale enterprises offering their services on several continents. Among the biggest investors we could cite:

- **Enel** will spend more than €11bn in 2025. The Italian utility plans to invest around **€210bn between 2021 and 2030**, including €40bn through third parties. Enel will focus on renewable energy, grid modernisation, and digitalisation. The company aims to have about 80% of its installed capacity from renewable sources by 2030.
- **EDF's** capital expenditure should reach €22bn in 2025 with a 2030 strategic vision plan that includes an investment programme of €100bn for renewables and nuclear energy to ensure a low-carbon energy mix.
- **Iberdrola** has outlined **a €150bn investment plan** in the period 2024-2030, with €12bn in 2025 alone. Iberdrola has a significant focus on offshore wind and solar projects. The Spanish utility aims to increase its renewable capacity between 2020 and 2030 from 35GW to 95GW.
- **Engie** wants to reach a total renewable capacity of 95GW by 2030. The French utility will invest another €10bn in 2025 and should maintain a similar investment level until 2030.

Looking at the top 20 European integrated utilities, about half of their investment will be dedicated to renewable energy while 30% will go to their network infrastructures. In comparison with 2018, utilities' investments into renewables represented 33% and conventional power generation 39% of their capital expenditure.

Half of integrated utilities' capex dedicated to renewables in 2025



Source: Company data, ING

+12% In capex for grid operators in 2025

If investment in the European utility sector grows by an average of 9% in 2025, our sub-segment representing the top 20 network utilities[3] should grow by an average of 12% to €54bn. Grid operators will see the biggest capex expansion again. Germany and the Netherlands are the two countries that are the most concerned about spiralling investment needs. For too long, the sector in the two countries has relied on coal and natural gas, and the transition has required a faster rollout of wind and solar power. This also includes drastic efforts to upgrade and build new grids.

[3] Top 20 European network utilities: Alliander, Amprion Elia, Enagas, Enexis, Eurogrid, Fluvius, Fluxys, Italgas, Fingrid, National Grid, Nederlandse Gasunie, Redeia, Redexis, REN, RTE, Stedin, Snam, TenneT, Terna

High investment in grids is a long-term theme

Between 2019 and 2025, the top 20 European grid operators will have almost tripled their yearly investments, from €19bn to €54bn. Taking into consideration all the players operating and developing gas and power infrastructure in Europe, BloombergNEF estimates total investments at €65bn in 2025 (the top 20 representing 83% of that amount). The information provider forecasts a long-term investment trend for grids and yearly capital expenditure of €95bn in 2030 and €157bn in 2040. While these amounts are huge, they are the amounts estimated to be necessary to accommodate the green energy coming online: offshore and onshore wind, solar, hydrogen, hydroelectric, geothermal and biomass.

Call 2: For grid operators, capex is overwhelming

Between 2020 and 2024, the debt burden of the top 40 European utilities has become heavier. By the end of 2020, we estimate the top 40 European utilities to have an aggregated €520bn in gross debt. By the third quarter of 2024 (or half-year 2024 for those reporting financials only twice a year), the gross debt burden of the group reached €890bn, a 70% increase within a five-year period. The expansion of the balance sheets can mostly be explained by the requirements imposed by the energy transition.

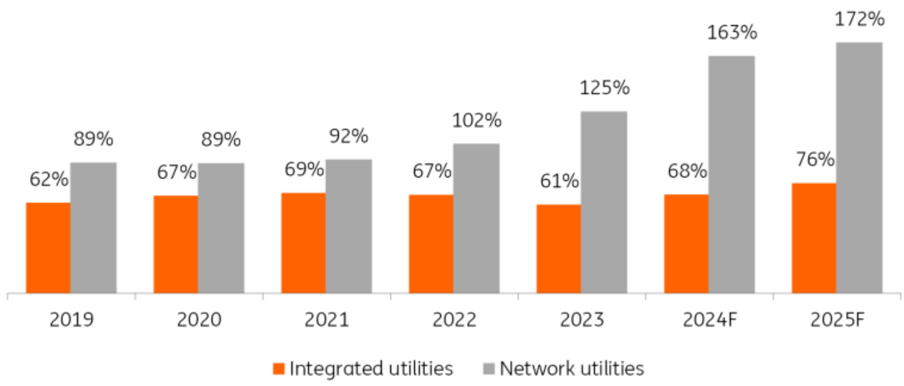
+70% European utilities' debt burden increased by 70% in the last five years

While gross debt has increased at a higher rate for integrated utilities, network utilities continue to have a much higher proportion of debt compared to the cash flow they generate. At the end of 2024, our top 20 European integrated utilities reached an average gross debt to EBITDA metric of 4.6x. This ratio is 6.9x for pure network utilities, with some grid operators close to a ratio of 9x. The level of investment is good news for network utilities as it allows them to grow their regulated asset base and thus their remuneration. However, their financial situation raises questions about the current and future health of the balance sheet, especially knowing that investments need to triple by 2040 to reach the bloc's net zero ambition.

Comparing EBITDA and capital expenditure for the sector, we expect the top 20 network utilities to reach an average capex-to-EBITDA ratio of 172% in 2025, meaning that more than 70% of capex funding cannot be made with organic cash flow generation. The ratio has gradually deteriorated since 2020 as the ambition for renewable energy has become stronger across Europe, pushing grid operators to upgrade and develop their networks.

For integrated utilities, the average capex-to-EBITDA ratio should reach 76% in 2025, indicating that capital expenditure alone can still be financed by cash flow generation.

Capex-to-EBITDA ratios for pure grid operators surge in 2019-2025F



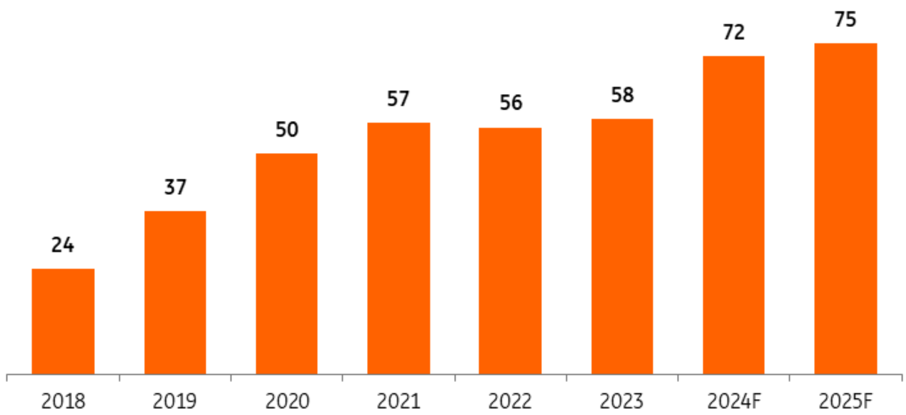
Source: Company data, ING

To fund the growing capital expenditure and dividend payments, European utilities have sought diverse solutions to meet their requirements. The bond and loan markets have been used extensively. Capital increases and shareholder loans are now also part of the solution to maintain credit metrics within boundaries.

€75bn Utilities will issue a minimum of €75bn on the euro denominated bond market

In 2018, Utilities issued a total of €24bn of bonds on the euro market. In 2021, the amount was €57bn and we expect a minimum of €75bn in 2025. On the bond market, hybrid bonds (with rating agencies classifying 50% of the amount as debt and 50% as equity) have flourished over the years, also as a tool to keep debt ratios within the minimum requirements of the ascribed credit ratings.

European utilities: bond issuance grows significantly 2018-25F (€bn)



Source: Markit, ING

Call 3: Capital increases and shareholder loans to the rescue

For years, European utilities have sold shares to fund their acquisitions in diverse markets. The capital increases of today reflect the need to gather funds to support the transition to sustainable energy systems. To cite a few, Enel, Iberdrola, EDF and RWE have all raised billions of euros in the last five years to finance the development of renewables or acquisitions to expand their activities in the green energy fields.

Traditionally the preserve of integrated utilities, pure network operators now also need to raise capital

Because of their size, their extended value chain and their presence on stock markets, integrated utilities have been able to raise new capital. For network operators, especially those not listed on stock markets, access to equity capital is a more difficult topic. But with skyrocketing investment needs, pure network operators now also need to raise capital.

National Grid rose £7bn in 2024 on the stock market. The Elia Group rose €600m, financed by its two main shareholders 80% by Publi-T and 20% KfW bank). It was not Elia's first capital increase as the Belgian and German network operator has received new equity several times since 2015.

Shareholders may prefer to provide funding in the form of shareholder loans which allow them to apply a fixed return through a defined coupon on debt. It also gives them the option of seeing their capital returned when the loan matures.

After its failed negotiations with the German state to dispose of TenneT Germany, the Dutch government has been obliged to provide TenneT with loan facilities for the continuation of the utility's investment plan. The Dutch state also has an agreement with the Dutch electricity and gas distribution players for equity injection or loans if necessary.

European utilities, both integrated and pure networks, will need to continue raising capital or benefit from shareholder loans to access funding. We expect new announcements in 2025. Without these actions, the deterioration of the players' balance sheet would lead to a further deterioration in credit metrics, and credit rating downgrades. After the quasi-bankruptcy of Thames Water and the difficulties of the UK Water sector in general, concerns could turn to the EU electricity network companies with investment levels that look less and less sustainable.

European Utilities: A bittersweet year for earnings

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In 2025, the European utility sector's cash flow generation will remain strong but will mark another contraction due to still-elevated power prices though these are now in a normalisation phase. Pure grid operators, meanwhile, will see cash flow generation expanding again.

Except for some outliers, European utilities' cash flow generation grew considerably between 2021-2023 on the back of surging power prices and demand catching up after the Covid-19 pandemic. Altogether, the top 40 European utilities[4] expanded their earnings before interest, taxes, depreciation and amortisation (EBITDA) from €134bn in 2021 to €183bn in 2023 with integrated utilities driving the strong growth. Within the sector, the sub-segment represented by pure grid operators saw its cash flow generation progressing at a slower pace with a growing remuneration linked to higher interest rates and a larger regulated asset base.

Call 1: Small earnings contraction for the sector in 2025

2024 was a pivotal year with the beginning of a normalisation in power prices. For the full year 2024, the European Utility sector should see an EBITDA decrease of 3% vs. 2023. According to their guidance for 2025, the top 40 European utilities will generate an aggregated €173bn in EBITDA, representing a 2% reduction in cash flow generation compared with 2024.

-2% Sector's EBITDA in 2025

European integrated utilities, whose activities stretch from grid operations, power generation, supply and customer services, are mostly responsible for the sector's EBITDA contraction. On aggregate, the top 20 European integrated utilities[5] guide to cash flow generation declining by 4% in 2025. Nevertheless, the picture is rather polarised. The business profile of the players matters. The least diversified utilities will tend to feel the full impact of the normalisation in European power prices. This is the case for most German and Nordic integrated utilities. On the other hand, others will continue to benefit from growth thanks to a well-diversified business profile including activities in North and South Americas, for instance, where energy needs are rising at a faster pace.

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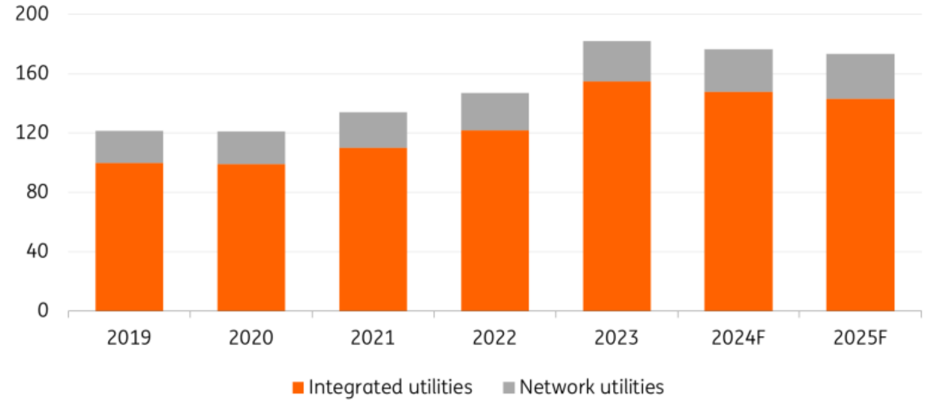
[4] Top 40 European utilities

[5] Top 20 European integrated utilities: A2A, Acea, EnBW, Enel, Centrica, CEZ, EDF, Enel, Engie, E.ON, Fortum, Hera, Iberdrola, Orsted, RWE, Statkraft, Suez, Vattenfall, Veolia, Verbund

On the pure grid operators' side, the top 20 network utilities[6] will continue to see their cash flow generation expanding (+6% in 2025) on the back of growing asset bases and supportive regulatory frameworks (although not in every country).

After a strong expansion, the top 40 European utilities' EBITDA will decline again in 2025



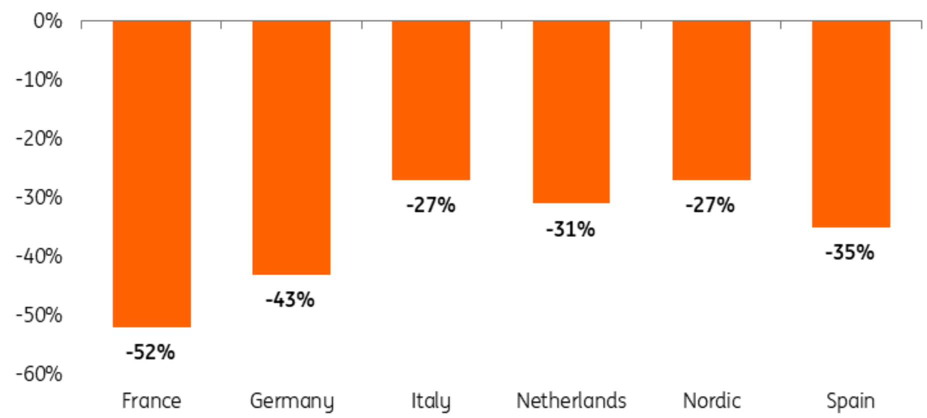
Source: Company data, ING

Call 2: Power prices have retrenched but should stay elevated in 2025

The vast majority of power generators sell at least 90% of their future power generation a year ahead of production. The current wholesale forward contracts generally impact utilities' cash flow generation 12 to 18 months later as payments are received when the contracts are executed.

In 2024, on a 12-month average, the wholesale 1Y forward contract was sold at €77/MWh in France, a 52% decline compared with 2023 when the average stood at €162/MWh. In Germany, the contract dropped by 43% from €140/MWh to €80/MWh on average. Electricity prices declined substantially but are still above the averages seen before the Covid-19 pandemic when contracts were signed between €40 and €50/MWh. All European countries registered lower wholesale electricity prices. European players found ways to diversify their natural gas procurement and a large part of the French nuclear fleet came back into operation.

Average wholesale prices significantly declined between 2023 and 2024



Source: BNEF, ING

[6] Top 20 European network utilities: Alliander, Amprion Elia, Enagas, Enexis, Eurogrid, Fluvius, Fluxys, Italgas, Fingrid, National Grid, Nederlandse Gasunie, Redeia, Redexis, REN, RTE, Stedin, Snam, TenneT, Terna

The price level at which European utilities hedge their power production in 2025 will impact their cash flow generation in 2026. Business and retail consumers will also feel the impact in 2026-2027 as their contracts are being readjusted on a rolling basis.

The energy crisis in 2022 was the result of a perfect storm. As in our scenario ‘Higher power prices’, demand surged as economic activity came back to normal levels after the peak of the pandemic. The conflict between Russia and Ukraine and the procurement issues that it created sparked the acute crisis. At the same time, France’s nuclear power fleet is running at very low capacity (more than 50% of its nuclear park was out of operation due to repair work).

We believe that our central scenario “stable” is the most plausible for 2025. Prices should evolve around the same base as seen in 2024. Power demand in the European Union should remain sluggish with modest GDP growth for most EU members. The French incumbent, EDF, the biggest power generator in Europe, has revised its nuclear power production upward from 315-345 TWh in 2024 to 335-365 TWh in 2025. While production will meet domestic demand, it will also allow production to be sold to neighbouring countries. Natural gas prices, characterised by volatility, could be the trickiest element. Even though the Dutch TTF contracts regained strength in 2024, our commodities strategists expect prices to somewhat retrench by the end of 2025 on higher liquefied natural gas (LNG) supply from the US. Despite higher volumes being a positive, a higher share of LNG supply within the European natural gas mix also means prices remaining at a certain level given more expansive procurement costs in comparison to Russian gas.

Scenarios for electricity prices

Lower power prices	Stable	Higher power prices
• Demand significantly drops on economic recession • Low natural gas prices • High wind, solar and hydro production • Nuclear power generation at high levels • Lower carbon prices	• Demand evolves between-1/+1% vs. previous year • Natural gas prices remain stable as well as carbon prices • Average wind, solar and hydro production • Nuclear capacity at optimal level	• Demand surges on strong economic growth • Natural gas prices escalate on high demand or procurement crisis • Moderate to low wind, solar, hydro production • High carbon prices • Significant nuclear outages

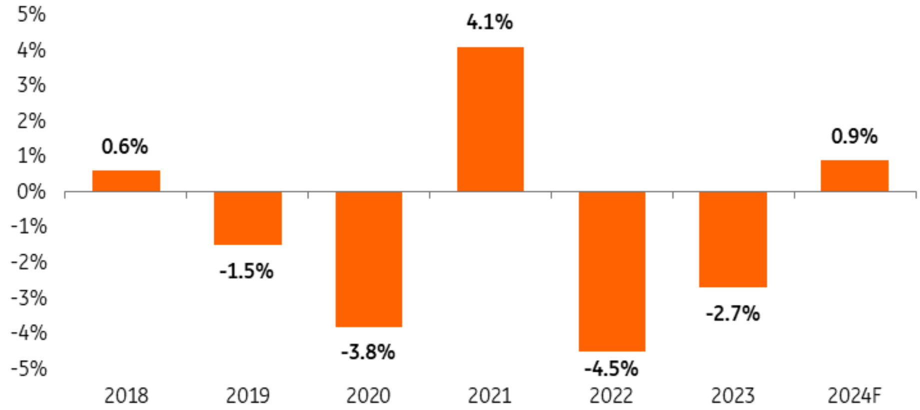
Source: ING

Electricity demand remains sluggish

Demand plays a role in determining power prices. The large recovery of electricity consumption across the European Union (+4.1%) in 2021 after the first wave of Covid infections influenced power prices. Following the recovery, 2022 and 2023 registered a significant decline in demand due to extremely elevated prices leading to consumers applying energy-saving strategies.

Data provided by ENTSO-E, the association representing 80 European power transmission operators and publishing statistics, suggests power consumption was up by 0.9% in 2024. Before the energy crisis, power demand fluctuated between +1% and -1% at the European level. With more than 70% of the power demand coming from industry, transport and commercial services, 2025 consumption will again largely rely on the bloc’s economic health. Signs of weaknesses seen already in Germany and France may not bode well for growth above the average seen before the Covid pandemic. In the longer term, electricity consumption growth should be supported by electrification. To mitigate the costs of the energy transition, some governments have adopted less supportive policies including the cancellation of subsidies for electric cars. Such actions may delay the energy transition and the expected growth in electricity demand in the EU.

In 2024, power consumption increased by a mere 0.9%



Source: ENTSO-E, ING

Natural gas prices will remain volatile

Natural gas prices have played a large part in elevated power prices in the last few years. Even though about 50% of Western Europe's electricity generation now comes from renewables, natural gas used by power plants has been the marginal cost for power generation, especially since coal has become a smaller resource for the utility sector. Pre-Covid, the Dutch TTF 1-year forward contract was traded in the range of €10-20/MWh. The conflict between Russia and Ukraine has had a significant impact on the natural gas market. August 2022 marks the highest spike in the Dutch TTF month forward contract with a price reaching €307/MWh. Since then, the price of the contract has tightened, and in March 2024, it was sold at €27.3/MWh. This was due to procurement issues being resolved, thanks to increased flows from Norway and LNG shipments from the US. Nevertheless, the price of the TFF contracts has remained volatile in the last three years and after the price retrenchment in 2023/2024, natural gas prices started to expand again to reach €49/MWh in the first week of January 2025.

The TTF 1M Forward contract has retrenched significantly but some volatility remains (€/MWh)

Source: BNEF, ING

Weather conditions have led to lower reserves at the European level. In the first week of January 2025, reservoirs were filled at c.69% and for countries such as the Netherlands and France, this level fell as low as 55%. The confirmation of the ending of the contract between Ukraine and Russia for transporting gas to Europe via Ukrainian pipelines added to the stress on natural gas prices. Our ING commodities strategist, Warren Patterson, predicts the TTF 1-month forward contract will trade at an average of €40/MWh in the first quarter of 2025 and €35/MWh by year-end. The LNG market is expected to add supply, with the US seeing new LNG projects coming online and adding c.15% in volume to current production. These price predictions hinge on the timely execution of these projects, as well as weather conditions that may either increase or decrease the urgency to refill reservoirs at a faster rate.

The elements influencing the power prices hedged by European utilities make the forecasts a difficult task. European utilities will publish their year-end 2024 results in February and March 2025 and their guidance should confirm (or potentially not) our stable scenario with wholesale power prices remaining at similar levels to those seen in 2024.

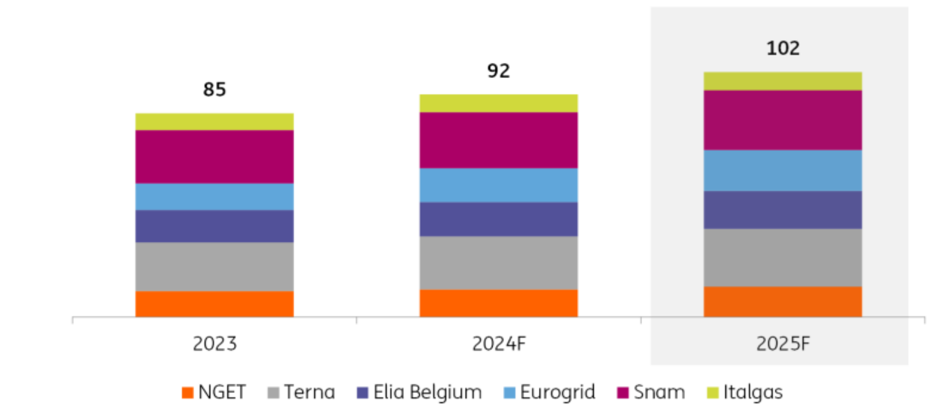
Call 3: Pure grid operators still benefiting from supportive regulatory frameworks

Within the sector, network utilities will see their EBITDA in 2025 growing by c.6% on average, a growth rate in line with 2024. The elevated capital expenditure programmes add new assets to the regulated asset base of grid operators. This base is the operators' assets that are used to provide regulated services such as power lines and gas pipelines. The regulated asset base usually serves as the base for regulated remunerations under allowed rates of return. Network utilities can also operate assets and provide services that do not fall under the determined regulated asset base.

+6% of EBITDA increase for pure grid operators in 2025

In our article "European Utilities in 2025: big investments and bigger debt," we describe the European utilities' investment plans for 2025. The sector will see investments growing by an average of 9% in 2025. The sub-segment top 20 network utilities will grow by an average of 12%, meaning that grid operators will see the biggest capex expansion again next year. Based on National Grid Electricity Transmission (NGET), Terna, Elia Belgium, Eurogrid, Snam and Italgas, the aggregated asset base of the six network operators will increase by c.11% in 2025 in comparison with c.8.5% in 2024.

Regulated asset bases grow significantly (€bn)

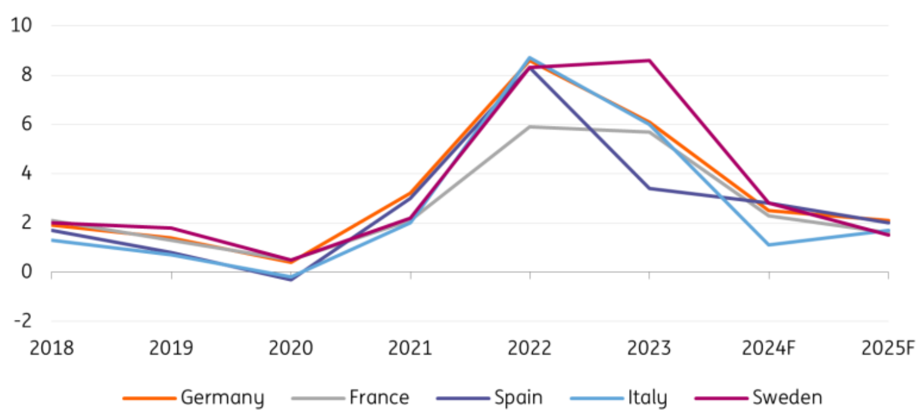


Source: Company data, ING

Regulated networks' remuneration will continue to be supportive in 2025 but could start to fall thereafter

Regulated remuneration on assets generally takes into consideration the operators' determined operating costs, cost of debt and cost of capital. In the period 2018-2022, European regulators tightened their frameworks with the aim of reducing baseline allowed returns as the companies' cost of debt significantly declined. The measures were also designed to counteract the higher returns seen in previous cycles and implement stricter cost controls on the utilities' operating expenses. From 2023 onward, the lower remunerations became inadequate in a number of countries. To operate their grids, utilities are themselves high energy users and with skyrocketing power prices in 2021-2023 and global hyperinflation, operating costs surged.

Consumer price indices (%)



Source: BNEF, ING

Alongside higher costs to operate their networks, corporates also saw their cost of debt increasing again in 2022 and 2023. Except for Spanish and Portuguese utilities, regulated frameworks allow for inflation passthrough. In 2024 and 2025, corrections for past inflation, capital and cost of debt will permit the sub-sector to continue growing its remuneration. The picture could start changing in 2026 as inflation and corporates' cost of debt have declined significantly. However, regulators should keep in mind that the energy transition requires very large investment needs and good remuneration is essential to maintain a debt burden at acceptable levels.

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