Energy Outlook 2026

Energy Markets Update

RaboResearch
Global Economics & Markets
knowledge.rabobank.com

Joe DeLaura
Senior Energy Strategist

Florence Schmit
Senior Energy Strategist

Summary

- Geopolitical tensions – spanning U.S.-Venezuela, Russia-Ukraine, U.S.-China – will continue to present headline risks to energy markets in 2026; however, price declines will dominate as a structurally stronger supply picture takes hold.
- We are slightly negative on crude prices over 2026 versus the forward curve, seeing an average of $58/bbl for Brent for the year and $54.5/bbl for WTI.
- We expect lower gas markets in 2026, with European and Asian LNG slowly converging to U.S. Henry Hub prices, compressing U.S. LNG export margins even as structural demand drivers keep U.S. gas consumption elevated. Global LNG supply will expand significantly with new U.S. and Qatari projects, stabilizing European balances, while Asian demand—particularly from China and Japan—will be the key swing factor influencing global price dynamics.
- We forecast TTF gas prices to average €27.50/MWh in 2026 and fall to €26/MWh in 2027, while JKM gas markets will reach $9.60/MMBtu in 2026 and then fall to $8.50/MMBtu in 2027.
- European power markets in 2026 will see continued renewable growth driving more frequent negative prices during high-output periods, while volatility persists due to reliance on gas during renewable lulls and coal phase-outs. Falling gas prices should ease generation costs and lower average wholesale prices but rising carbon costs and structural intermittency will keep price swings and scarcity pricing as defining features of the market.
- From 2026, the EU's Carbon Border Adjustment Mechanism enters its full regime alongside the gradual phase-out of free allocations, tightening compliance obligations and reinforcing demand for EUAs as auction supply falls by about 10% and REPowerEU front-loading ends. These structural shifts, combined with full maritime inclusion and modest demand uplift from cheaper energy, are expected to push carbon prices above €90/t by 2027.

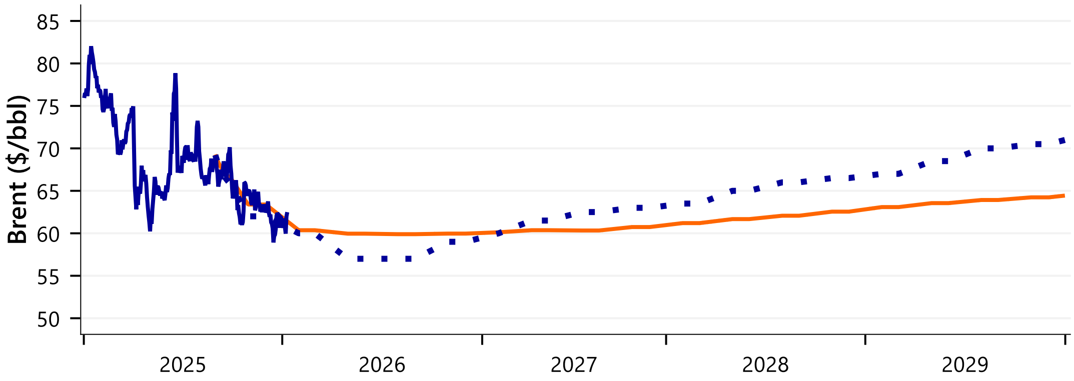
Crude and Refined Products Outlook

Crude Oil

Crude oil markets slumped in 2025, with Brent starting the year at $74.93/bbl and ending at $60.85/bbl. WTI followed a similar trajectory from $71.85 down to $57.42/bbl. The wild ride down involved a steep selloff in March and April from the implementation of US President Donald Trump's sweeping global tariffs, a brief summer spike from the US bombing of three Iranian nuclear facilities, and the slow trend downward in the second half of the year as OPEC continually returned voluntary cuts of oil production to the market.

Our estimates remain that Brent will average around **$60 in Q1 2026**, in a range between $56-$64/bbl. **The oversupply narrative will continue and inventories will build and push prices to average $55-$60 for the rest of 2026, averaging about $57/bbl.** We expect a few steep, short selloffs sub-$55 throughout the year as the narratives around oversupply panic and overshoot. **We do not see it likely that Brent trades for any extensive time, if at all, in the $40s**. For WTI, we expect the discount to stay around $4/bbl less than Brent, only strengthening later in 2026 to -$3.6 as US production slows down.

Figure 1: Brent crude oil forecasts: 1H risks to the downside, but slowing production and inventory stockpiling will lead to a pickup in prices in Q4



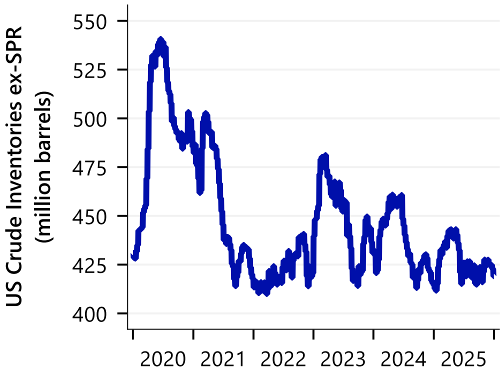
Source: Bloomberg, RaboResearch 2026

The Global Market Is Oversupplied, and Inventories Should Build

The overall concern voiced by the IEA, EIA, and many other analysts and banks is that oil markets throughout 2026 will be vastly oversupplied. The IEA has been especially bearish, with their most recent forecast calling for 3.5-4m b/d of oversupply. For comparison, during the COVID lockdown shock year of 2020, oil markets were oversupplied by about 2.7m b/d.

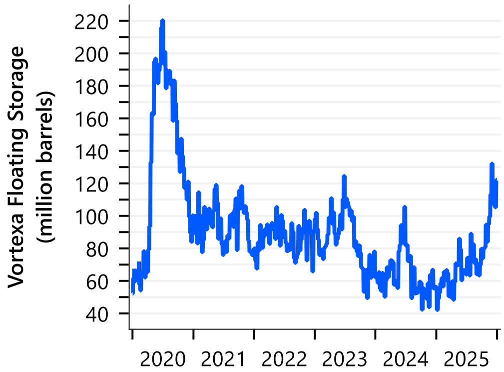
We agree up to a point that markets will be oversupplied and inventories will build, but not to the same depth as their overly bearish conclusions. The oil market is tight and extra supply and barrels in storage will help to provide a cushion against larger geopolitical events or supply shocks.

Figure 2: US stockpiles (and global inventories!) are still very low comparative to historic levels



Source: Bloomberg, RaboResearch 2026

Figure 3: Barrels held in floating storage are building, showing the oversupply is imminent



Source: Bloomberg, RaboResearch 2026

Inventories in the US are close to multiyear lows – part of the reason that Brent and WTI prices have languished as the oversupply narrative has taken over the markets since last summer. There has to be evidence that supply is outstripping usage!

The first piece of the oversupply argument comes from the large increases of oil production in 2025. US, Brazilian and Guyanese supply ramped up, while the OPEC cartel has raised output targets by around 2.9 million b/d from April to December 2025 and, at their last meeting in November, paused hikes for the first quarter amid all the predictions of a looming oversupply. However, at current production levels, most of OPEC's members are close to their production capacity, with only Saudi Arabia, the UAE and Iraq having meaningful spare capacity.

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OPEC+ is highly unlikely to make any changes to their output policies for now, and we expect no further production hikes in 2026. The only change we do see looking ahead will be eventual discussion to cut supply once oil prices begin trading in the low $50s.

One source of recent price support since mid-October have been the ongoing Ukrainian attacks on Russian export terminals and refineries. OPEC member Kazakhstan's recent overproduction is coming to an end as their Tengiz oil fields have seen a drop in exports due to the November 29 Ukrainian attacks that destroyed part of the CPC oil terminal. Kazakhstani oil output has been down about 6% to 1.93 million b/d since November. The strikes have had a marked effect on Russia's ability to supply refined products to India and China. At the same time, the last round of US sanctions on Russia attempting to curtail buying by India and China (through high secondary tariffs and sanctions on Lukoil and Rosneft, Russia's two largest oil companies) to the point that Indian refiners started to halt buying of Russian blends and bid for Middle Eastern barrels instead. This switch dramatically pushed up diesel and gasoil crude crack spreads, as the middle distillates markets remain in long term inventory deficits versus seasonal norms.

Our recent piece about a theoretical Russia-Ukraine peace deal would bring the middle distillates markets back closer to reality, but that market remains fragmented and unable to meet growing demand. So the narrative continues that crude will likely sink in the coming quarters, but diesel and marine fuels will stay stronger in a relative sense from a pricing perspective.

This ties into a third reason that markets will see some support: one of the main tenets behind the oversupply narrative is that oil demand growth is slowing down. This is correct, but not quite the entire story. Diesel demand, jet fuel demand, and heavy marine fuels are ALL still increasing, albeit at slower rates than the last twenty years. The decrease is mainly gasoline. Gasoline demand is expected to peak in 2028 by our forecasts, led by China's incredible rise of BEV sales, and Europe also switching toward electric vehicles. Even demand for gasoline in the US has been stagnant since 2018. This divergence in products is a major refinery throughput problem that is not easily rectified. Lower gasoline demand lowers gasoline crack spreads, but other products' crack spreads must increase to make up for this lower profitability. This is why diesel remains strong comparatively; increasing demand plus lack of capacity to build up inventories for it! Oil refinery throughput will be strong to create the OTHER products that are still woefully undersupplied and in demand!

Fourth, a key source of unnoticed demand for those excess oil barrels: China will see lower prices as a second opportunity to restock their SPR. Lower oil prices in 2025 prompted China to fill their strategic inventories, buying between 500k and 1m b/d. China slowed their buying in October after the US instituted sanctions against Rosneft and Lukoil. Any lifting of sanctions will see a continuation of the earlier trend of aggressive restocking, and if the Chinese loved buying strategic barrels at $65, they will certainly love buying more SPR barrels lower.

The US SPR will also take advantage of low prices. According to an article by Bloomberg, "Trump's sweeping tax-and-spending law passed over the summer [of 2025], Congress only appropriated $171 million for oil purchases for the SPR between 2025 and 2029 — a limit the government could hit very quickly. That sum equates to less than 3 million barrels at current prices, which is a far cry from the roughly 300 million barrels needed to bring the SPR to full capacity."

While this is true, did we forget that Donald Trump has shown what the will to power can accomplish? Will a simple appropriations bill halt a terrific deal? We think not. The US will simply appropriate more or find a way under the Defense Production Act to purchase crude for the SPR at lower prices

Lastly, OPEC+ will respond to lower prices through supply cuts or through the refined products market. As we mentioned before, back in November eight OPEC members decided to pause further production increases during the first quarter of 2026 after signs that a long-awaited glut is finally arriving. OPEC will not just sit around and wait while their governments' main sources of

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income are chopped by billions of dollars. Saudi Arabia has shown multiple times over the past decade that they will rally their allies and try to wrest control of prices through cuts. Production cuts also mean that Saudi Arabia, the UAE, Iraq and Kuwait do not have finance the upkeep and development of oil fields for "spare capacity." Less spare capacity aids the longer-term goal of tighter oil markets, and thus higher pricing. In a flattening growth market, new supply has to be ruled and controlled with an iron fist to keep prices high!

Inventories will build this year, but not at the record pace forecasted by so many others, because there be imperfect access. Russian barrels may remain stranded. Physical oil deliveries will get backed up. Capital expenditures will be cut back. OPEC will react, and so will the physical traders, producers, and refiners. It's not all simple math.

U.S. Production and Demand

We are already witnessing responses to ongoing lower prices in the US. The Permian Midland, Permian Delaware, Eagle Ford and Bakken basins combined are responsible for ~70% of current US oil production of 13.8 million barrels per day. Breakevens for these four basins are between $57-62/bbl (WTI). Oil producers have already started cutting active drill rigs: rig counts compiled by Baker Hughes have steadily dropped all year since March, reaching new multiyear lows of 406 active oil rigs in December.

However, oil production in 2025 in the US grew to 13.53m b/d (yearly average) vs 2024 13.26m b/d for a total year-over-year growth of 260k b/d, which may seem at odds with lower rig counts. We must underline that drilling rigs have become more efficient with longer lateral drilling capabilities, better cycling times and longer times spent on the pad. Output per rig is higher even as total estimated ultimate recovery per well is declining. So, the efficiency gains we are witnessing are from front loading the production from wells into the first six months after completion, which also means the flatter part of the decline curve becomes less important. In effect, production numbers are becoming more responsive to real demand. We still expect US production to shrink by 160k b/d in 2026 from the December production numbers of 13.8m b/d, and further down 200k b/d in 2027.

Gasoline demand in the US recorded a decrease of 57k b/d to 9.675 million b/d year-over year, down 400k b/d from the 2018 and 2019 demand numbers of 10.07 million b/d. Diesel and distillates demand have held around 5m b/d from 2021 to the present, down about 240k b/d from the pre-COVID highs of 5.294 million b/d.

Work from home policies continue to weigh on passenger vehicle demand, and while the US lags behind in BEV and PHEV vehicle adoption, sales still remain above 10% of total new car purchases.

Venezuela

The recent capture of Nicolas Maduro by the US further heightens our ongoing thesis that Donald Trump and the US are undergoing a new vision of "might-is-right" grand macro strategy with a goal of putting pressure on China and other geopolitical rivals. We covered the topic of Venezuela extensively in our November paper Vene(zuela), vidi, vici?

Venezuela produced about 3.2m b/d of oil in the early 2000s and currently produces about 900k b/d, of which 800k b/d is exported. The US receives about 100-115k b/d of those exports as Venezuela produces a heavy, sour grade of crude that's key for many US refineries along the Gulf Coast. Nearly 100% of the rest of Venezuela's exports go to China or Cuba, and the US has now forced PDVSA and the Venezuelan government into new contracts. China receives about 4% of their oil imports from Venezuela and can easily make the switch to importing more Canadian sour or turning to the Middle East. Trump has already claimed that Venezuela will send the US "fifty million barrels" which is about 120 days worth of exports.

Despite the US attacks on Saturday January 3, none of Venezuela's oil infrastructure was affected, and any short-term implications are minimal. Venezuela is not a large percentage of the world's oil supply, and as we discussed the oversupply narrative any disruptions are even less of a factor in 2026. Going forward is the main issue. To quote Trump himself:

> "We're going to have our very large United States oil companies — the biggest anywhere in the world — go in, spend billions of dollars, fix the badly broken infrastructure — the oil infrastructure — and start making money for the country," Trump said in a Saturday press conference. Hours earlier in an interview with Fox News he said the US was going to be "very strongly involved" in the Venezuelan oil industry.

Venezuela will thread the needle of diplomacy as the US has demanded that the country must kick out China, Russia, Iran, and Cuba from their oil network and sever economic ties with them. Additionally, the US has demanded that Venezuela must agree to partner exclusively with the U.S. on oil production and favor America when selling their heavy, sour crude oil.

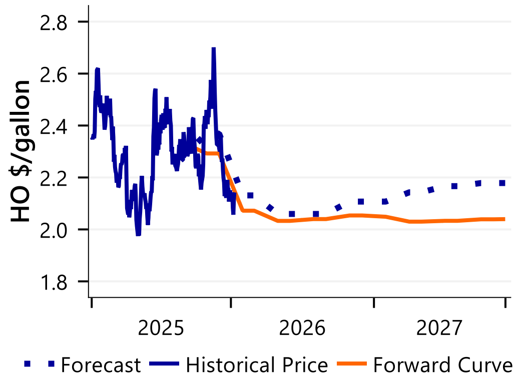
But, the state of Venezuela's oil pipeline network and oil fields are likely so degraded after years of underinvestment that it will take at least five to seven years and tens of billions of dollars of investment plus security guarantees to get production up to 2 million b/d or more. The situation is still very fluid at the moment, but we expect the news to be more airy and grandiose headlines and little actual change to the physical flows of oil in the short term.

Refined Products

Let's turn our attention to the continuing divergence of gasoline and heavier distillates. Our longtime thesis since 2022 is that the world is in a new era of flattening and shrinking gasoline demand, and steadily, but slow growing diesel demand. This comes from the fact that work from home policies in service-oriented countries have decreased commuting demand since 2020, alongside the rise of battery electric and plugin hybrid vehicles (BEVs and PHEVs). On the other hand, diesel remains the foremost fuel for agricultural, mining, and construction equipment on top of the major driver of logistics and supply chains, and still remains a backup fuel for electricity generation in many middle-income and low-income countries. Furthermore, the US and EU are shedding refining capacity, which has exacerbated this supply-demand imbalance. Lastly, to top it all off, global medium- and heavy-distillate inventories remain close to multi-decade lows.

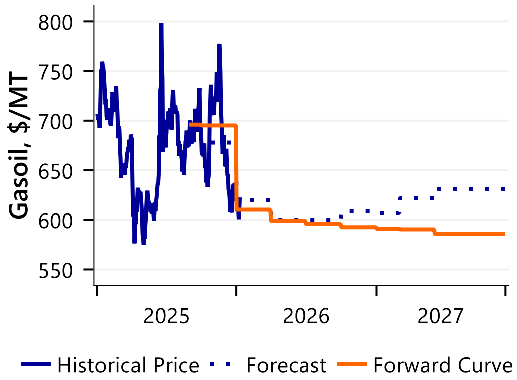
Combining all of these factors with our crude oil forecasts implies that there is some downside in Q1, Q2 and Q3 to NY Harbor ULSD (HO) prices and ICE Gasoil prices versus the current forward curve. We see opportunity for hedging HO sub $1.95/gal for 2026 and 2027, and below $575/mt for gasoil.

Figure 4: ULSD Diesel forecasts: stronger than crude from robust crack spreads



Source: Bloomberg, RaboResearch 2026

Figure 5: Gasoil forecasts: weaker than HO, stronger than Brent with refinery closures



Source: Bloomberg, RaboResearch 2026

Gas, Power, Carbon Outlook

U.S. Gas Markets: A Record-Breaking Year and What's Next

U.S. gas markets closed 2025 on a historic high, setting new records across production, exports, and demand. Dry gas output averaged 108 bcf/d, the highest on record, driven by robust growth in key basins. LNG exports also reached unprecedented levels, averaging 16.4 bcf/d, as new liquefaction capacity came online and global demand remained strong. Total U.S. gas demand—including LNG feedgas—hit 114 bcf/d, another record, supported by resilient industrial activity and strong residential consumption through the year.

Looking ahead, the outlook for 2026 remains constructive, though the dynamics are shifting. Our forecast for European TTF and Asian JKM gas prices points to a decline, narrowing the spread to Henry Hub. This convergence will reduce the arbitrage advantage for U.S. LNG exports, particularly as global markets rebalance. At the same time, any stronger-than-expected lift in U.S. gas prices—supported by domestic fundamentals—will amplify this trend, further compressing margins for exporters. **We forecast Henry Hub prices slightly below the current forward curve for 2026 at around $3.40/MMBtu vs. $3.54/MMBtu. We see prices moving higher in 2027 to $3.85/MMBtu in 2027 vs. the forward curve at $3.67/MMBtu. There is further upside risk if demand surprises to the high side from winter usage, LNG exports and data center utilization.**

Despite these price dynamics, structural demand drivers remain firmly in place. LNG expansions will continue to underpin U.S. gas consumption, with additional capacity scheduled to start up in 2026. Even with Energy Transfer's recent decision to pull out of its Lake Charles LNG project, the pipeline of new facilities—such as Golden Pass LNG—will keep LNG feedgas demand elevated. Beyond exports, the rise of AI and data center power requirements is emerging as a significant new lever for gas demand. This could add between 2.4-2.6Bcf/d of demand to the mix in 2026, according to our latest calculations.

On the supply side, production growth is set to continue, albeit at a slower pace. The EIA projects U.S. dry gas output to average around 109 bcf/d in 2026, supported by efficiency gains and steady drilling activity. While associated gas from oil plays remains a key contributor, producers are signaling capital discipline, which could temper upside potential.

U.S gas storages are much higher than the 15-year average as winter 2025-2026 started with some strong cold potential that has petered out. We expect inventories in March to bottom out at **1,790bcf** currently with a total gas draw from the fall highs of 2,170bcf. This translates to a very bearish and healthy level of inventories to start the spring. High storage levels in 2026 will contain major price spikes for Henry Hub prices despite our forecast increase in overall demand until the winter. The combination of strong LNG feedgas requirements, industrial resilience, and emerging power sector demand suggests that U.S. gas markets will remain tight enough to sustain prices going forward. We see it extremely likely that spring pricing will fall below $3/MMBtu and only pick up during heat waves in the summer and from LNG demand later during the year.

In summary, 2025 was a year of records for U.S. gas—production, exports, and demand all at historic highs. As we move into 2026, narrowing global price spreads and potential U.S. price strength will reshape trade economics, but structural demand growth from LNG and AI-driven power needs will keep the market well-supported.

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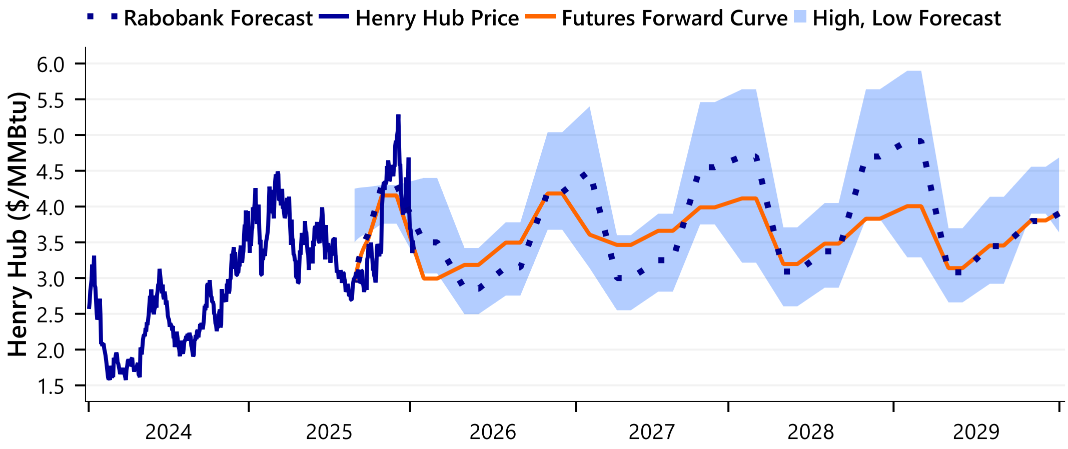
Figure 6: We forecast U.S. Henry Hub prices at $3.40/MMBtu in 2026.



Source: Bloomberg, RaboResearch 2026

LNG Supply Growth Eases Tightness Despite Russian Phase-Down

The European gas market enters 2026 in a markedly different position than the crisis years of 2021–2022. While Russian pipeline flows have dwindled to negligible levels following EU phase-out measures and sanctions (with Russian pipeline gas imports accounting for only 3% of imports and Russian LNG accounting for 13% of inflows in 2025), the structural shift toward LNG has stabilized supply security. The coming year will see incremental improvements in global LNG availability, primarily driven by new capacity from the United States and Qatar, which should help ease the residual tightness in European gas balances. Global LNG export capacity is expected to rise by 8% in 2026 from 2025 levels, while we forecast total available supplies will come in at around 460 million tons. Several large-scale LNG projects are scheduled to ramp up in 2026, adding significant volumes to the global pool. The United States remains the dominant growth engine, with expansions at Gulf Coast terminals and new projects like Golden Pass LNG expected to deliver substantial capacity. Qatar's North Field expansion will also begin contributing meaningful volumes, reinforcing its position as a cornerstone supplier. Russia has also further LNG capacity expansions in the pipeline for 2026, with availability of its fleet to be improved if sanctions on its Arctic LNG 2 plant are lifted in the event of a Ukraine-Russia ceasefire or peace agreement.

For Europe and its energy prices, these developments are critical. The EU's deliberate phase-out of Russian pipeline gas and LNG—cemented by regulatory bans and infrastructure reconfiguration—has left (U.S.) LNG as the primary marginal source of supply. While Europe successfully navigated the transitional years through aggressive LNG procurement and demand-side adjustments, the additional U.S. and Qatari volumes in 2026 will provide a cushion against volatility, reducing the risk of price spikes during seasonal demand peaks. A Ukraine-Russia peace would only further lift LNG supply availability on the global market.

European Demand Outlook: Modest Recovery, But No Surge

We forecast European gas demand to remain broadly stable in 2026, with only a slight uptick compared to 2025. Lower wholesale prices—enabled by improved LNG availability—could stimulate incremental consumption in energy-intensive industries and gas-fired power generation. However, structural factors such as ongoing electrification, efficiency gains, and policy-driven decarbonization will cap any significant rebound.

Overall, LNG demand in Europe is unlikely to rise by more than 3–4% year-on-year, reflecting a plateauing trend after the sharp adjustments of recent years due to a switch away from Russian gas. This restrained growth also underscores the maturity of Europe's gas transition: while price signals may encourage short-term flexibility, the long-term trajectory remains aligned with declining fossil fuel use.

Asia Holds the Key

Despite Europe's improved supply outlook, global LNG market dynamics will hinge on Asia. The region accounts for roughly 62% of global LNG imports, and its demand trajectory in 2026 will be the single most important determinant for global gas prices. If Asian demand growth accelerates beyond expectations—driven by economic recovery, coal-to-gas switching, or weather-related factors—the additional U.S. and Qatari volumes could be absorbed quickly, tightening the market and pushing prices higher.

Conversely, if Asian demand remains subdued, Europe could benefit from softer spot prices and greater flexibility in attracting cargoes. This asymmetry highlights the interconnected nature of LNG markets. One key metric to watch in 2026 is China's LNG demand, which has weakened significantly. Preliminary data for 2025 shows LNG imports down almost 13% year-on-year, reflecting a combination of tariffs, rising pipeline supplies, and robust domestic gas production. Pipeline imports—currently about 18% of China's gas demand—are set to rise by roughly 6 bcm/year if deliveries via the Power of Siberia 1 line expand as scheduled. Domestic production, which already covers 60% of demand, continues to grow steadily, reducing the need for LNG.

Looking ahead, LNG demand erosion could accelerate between 2027–2030 with the planned expansion of the 12 bcm/year Far Eastern Route (FER) and the proposed 50 bcm/year Power of Siberia 2 (PoS2) pipeline. While PoS2 remains uncertain, even the FER addition could lift Russian pipeline gas to 13% of China's pipeline imports, up from the current 9%. This structural shift means China's LNG imports will likely stagnate or decline, removing a major source of global demand growth.

With China taking a step back, Japan maintained its position as the second largest LNG importer in 2025, and its role in 2026 and beyond will be pivotal. Unlike China, Japan lacks pipeline alternatives and remains heavily reliant on LNG for power generation and industrial use. However, Japan's demand outlook is nuanced. Continued nuclear restarts and aggressive renewable deployment could cap LNG growth in the long-term, especially in baseload power. Around 550MW of gas-fired and up to 5.1GW of coal-fired capacity is expected to be decommissioned in Japan by 2030, while around 3.4GW of new nuclear capacity will be added to the mix between 2029-2030. This will weigh on gas use in the power sector later this decade.

In short, Japan will remain a cornerstone of LNG demand, but its growth potential is limited compared to historical peaks. This means that any upside surprise in Asian LNG demand—and thus global price tightening—would likely come from South and Southeast Asia (India, Vietnam, Thailand), rather than Japan or China.

Price Outlook and Strategic Implications

Our base-case projections suggest that European hub prices in 2026 will trend lower than the 2023–2024 averages, supported by supply growth and stable demand. We forecast TTF gas prices to reach an average of €27/MWh in 2026 and fall to €26/MWh in 2027, while JKM gas markets will reach $9.60/MMBtu in 2026 and then fall to $8.60/MMBtu in 2027. However, volatility risks persist, particularly if Asian demand surprises to the upside or if project delays constrain expected LNG additions. Storage adequacy and infrastructure resilience will remain critical, especially during winter periods when Europe's reliance on LNG peaks.

For industrial consumers and power generators, a more benign price environment could offer temporary relief, improving competitiveness and reducing energy costs. Yet, this should not obscure the structural reality: Europe's gas system is now fundamentally linked to global LNG markets, and price stability will depend on factors far beyond regional control.

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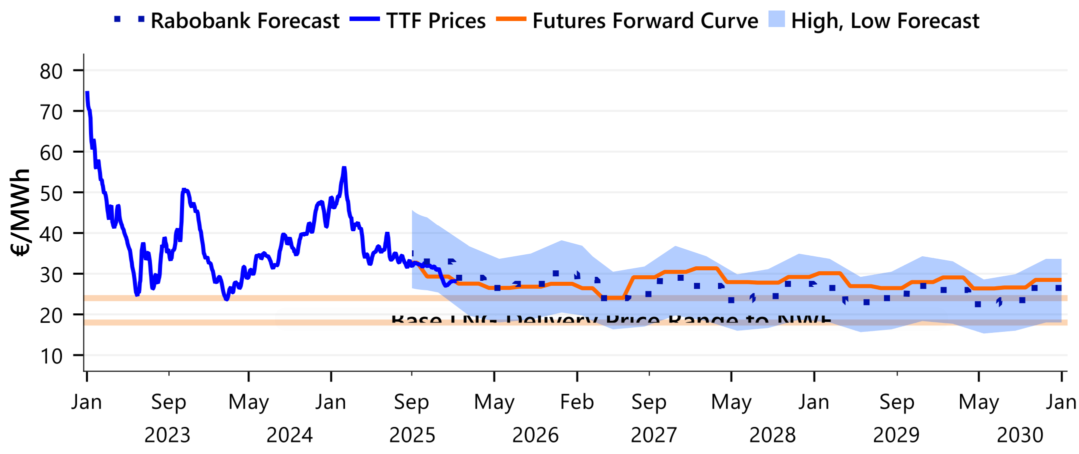
Figure 7: We forecast TTF gas prices at €27/MWh in 2026.



Source: Bloomberg, RaboResearch 2026

European Power

The European power market in 2025 reflected a dynamic interplay between renewable growth, hydropower variability, and fossil fuel – particularly gas - reliance. These factors have shaped both the generation mix and wholesale electricity prices, and they will continue to influence the outlook for 2026 and beyond.

In 2025, wind and solar generation accounted for 32% of the EU's electricity mix, up from 30% in 2024, according to latest Ember data. This increase underscores the ongoing expansion of renewable capacity. Solar generation has become particularly prominent during summer months, often emerging as the largest single source of electricity in the EU. Wind power also continued to grow, supported by investments in both onshore and offshore projects, although output remained sensitive to weather conditions in 2025. The combined strength of wind and solar has led to a renewed surge in negative hourly power prices across many European markets in 2025. Countries such as the Netherlands, Germany, Spain, and France recorded new records for negative prices, each surpassing 500 hours during the year. By contrast, the UK saw fewer than 200 hours of negative pricing, reflecting its different generation mix and flexibility options. What is striking, however, is that these same markets also experienced a surge in hours clearing above €100/MWh, with Germany and the Netherlands leading the pack at more than 3,000 hours each. This dual trend underscores the growing volatility in European power markets: deep lows when renewable output overwhelms demand and sharp highs when intermittent generation falters and gas-fired plants set marginal prices.

This pattern is expected to persist—and even intensify—as more renewable capacity enters the system. Negative prices will become more frequent during periods of high solar and wind output combined with low demand, while scarcity pricing will remain a feature during renewable lulls, especially in winter. Coal phase-outs and weaker hydropower amplify this dynamic by reducing baseload resilience, leaving gas as the primary balancing fuel. Even with falling gas prices, rising carbon costs will impose a structural floor on power prices whenever gas is needed, ensuring that while average prices may decline, volatility will remain a defining characteristic of the market.

Despite this progress, hydropower generation has declined slightly in 2025 compared to previous years. Seasonal variability and lower water availability have constrained hydro output, reducing its contribution to the overall mix. This shortfall has had a knock-on effect: gas-fired generation has stepped in to fill the gap, reinforcing the role of natural gas as a flexible backup fuel. As a result, fossil fuel use—particularly gas—rose marginally in 2025, even as renewables expanded.

This increased reliance on gas-fired power has pushed wholesale electricity prices higher during 2025. Gas remains the marginal fuel in many markets, often setting clearing prices. When renewable output dipped or demand surged, gas plants operated more intensively, amplifying price volatility and contributing to upward pressure on power costs. German and Dutch day-ahead power prices averaged over €85/MWh in 2025, a rise from the €77-79/MWh levels recorded in 2024.

Looking ahead to 2026, the outlook for gas prices suggests relief for electricity markets. **Our forecasts point to a decline in European gas prices from the elevated levels seen in 2025, which should ease generation costs and help lower wholesale power prices.** Even though gas will continue to play a critical role in balancing the system, cheaper gas will reduce its impact on overall price formation. At the same time, the expected surge in renewable capacity—particularly solar —will further dilute gas's influence on clearing prices. As more intermittent generation enters the grid, periods of abundant renewable supply will become more frequent, exerting downward pressure on wholesale prices.

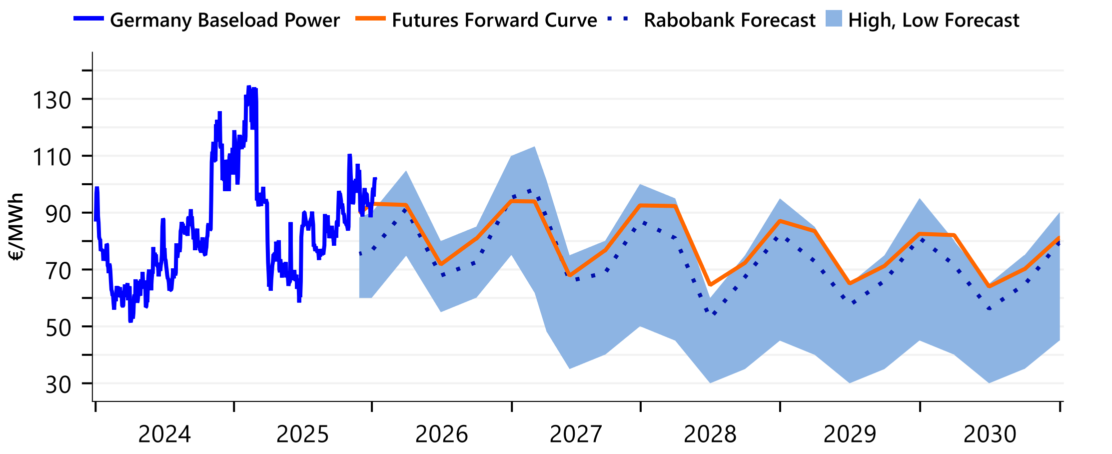
Renewable growth remains a central theme for 2026. Utility-scale solar projects and offshore wind developments are set to expand yet again, raising the combined share of wind and solar beyond the 32% achieved in 2025. However, the outlook for hydropower is less optimistic. With most large-scale hydro opportunities already exploited and seasonal variability persisting, hydro is likely to remain a stable but shrinking component of the EU generation mix.

Coal phase-outs will also shape the market in 2026. Greece, for example, plans to close its remaining coal-fired plants by that year, accelerating the transition away from high-emission generation. While this is a positive step for decarbonization, it will increase reliance on gas-fired units during periods of low renewable output, reinforcing gas's role as a flexible backup fuel. This dynamic could sustain some volatility in gas demand and spot power prices, even as the broader trend points toward lower averages.

Another important factor is the trajectory of carbon prices. The EU Emissions Trading System (ETS) continues to tighten, and rising carbon costs will eventually put a floor under power prices whenever gas-fired generation is required. Even if gas prices fall, the cost of carbon allowances adds a structural component to generation costs, ensuring that power prices cannot decline indefinitely. This mechanism will become increasingly relevant as coal exits the mix and gas remains the primary fossil fuel for balancing intermittent renewables.

For 2026, we forecast German and Dutch baseload power prices to fall to €77-79/MWh, a roughly 11% decline from 2025 levels. The combination of high renewable and nuclear generation will maintain even lower prices in Spain, which we forecast to fall to €60/MWh, while we expect UK power prices to fall only marginally to £77/MWh.

Figure 8: We forecast German baseload power prices to fall to €79/MWh in 2026.



Source: Bloomberg, RaboResearch 2026

European Carbon

CBAM becomes (quasi) financial in 2026

From 1 January 2026, the EU's Carbon Border Adjustment Mechanism (CBAM) moved from its transitional reporting phase to the definitive regime: importers of cement, iron & steel, aluminium, fertilisers, electricity and hydrogen will have to purchase CBAM certificates priced off the EU ETS auction average and surrender them annually against embedded emissions. This aligns the carbon cost of imports with domestic production and is synchronized with the phase out of free allocation in the EU ETS to prevent carbon leakage. While CBAM certificates are distinct from EUAs, their price is pegged to EUA auctions, increasing the salience of EUA price formation for importers and, by extension, for hedging/abatement strategies. The Commission has recently expanded the scope of CBAM and, together with Parliament, signalled active work on downstream extensions and anti-circumvention measures. In 2025, a public consultation was launched on extending CBAM to selected downstream products—particularly steel- and aluminium-intensive assembled goods—and on indirect emissions. From 1 January 2028, these downstream products (like machinery and appliances) could be included in the scope of CBAM. Including assembled goods, or products such as cars and washing machines in the scope of CBAM increases the number of sectors exposed to carbon prices and in turn reinforces expectations of sustained demand for EUA allowances.

Free allocation reduction from 2026 adds a structural bullish impulse

Under the Fit for 55 reforms, the EU tightened the carbon emissions cap (targeting a 62% reduction vs. 2005 by 2030), raised the linear reduction factor, and scheduled two "rebases" (90 million in 2024, 27 million in 2026). Crucially, free allowances begin phasing out from 2026, with CBAM sectors (e.g., steel, cement) losing free allocation in step with CBAM phase in through 2034, and non leakage sectors moving to zero by 2030. The aviation sector will lose access to free allocation in 2026 entirely. This structural withdrawal increases net auction demand and compliance exposure for industry, supporting EUA prices. The implementation of the EU ETS II for fuel for road transport and building was however delayed by one year to 2028.

Lower energy prices in 2026: a demand side uplift

Rabobank's market views for 2026 point to easier gas and power fundamentals driven by a surge in global LNG supply and strong renewables build out, with our forecasts for TTF gas pointing to the high €20/MWhs and wholesale baseload power to come off from 2025 levels as renewables growth outpaces demand. Cheaper fuel costs typically raise running hours for thermal units at the margin and can make some industrial operations more viable, thereby lifting EUA demand from the power sector and energy intensive industry versus the crisis years. That said, the magnitude is system dependent: lower energy cost will support some higher gas use in power generation and industry while a continued decline in coal use is expected to have a more pronounced impact on overall demand for carbon allowances.

Shipping: 100% inclusion and calendar adjustments

Maritime transport entered the EU ETS in 2024 at 40% coverage, rose to 70% in 2025, and reaches 100% in 2026. In parallel, non CO_2 gases (CH_4 and N_2O) from maritime are accounted for, with auction calendars adjusted to cancel allowances where surrendered volumes were below verified emissions in the phase in years—tightening the system's environmental integrity and effectively reducing auctionable supply. The Commission's revised 2026 auction calendars already reflect 54.24 million cancellations related to 2024 maritime surrender shortfalls and add volumes for non CO_2 coverage, while confirming full maritime compliance from 2026. This full phase in raises hedging/compliance demand from carriers and shippers and hardens the structural demand base for EUAs.

Supply side in 2026: fewer allowances and the end of REPowerEU front loading

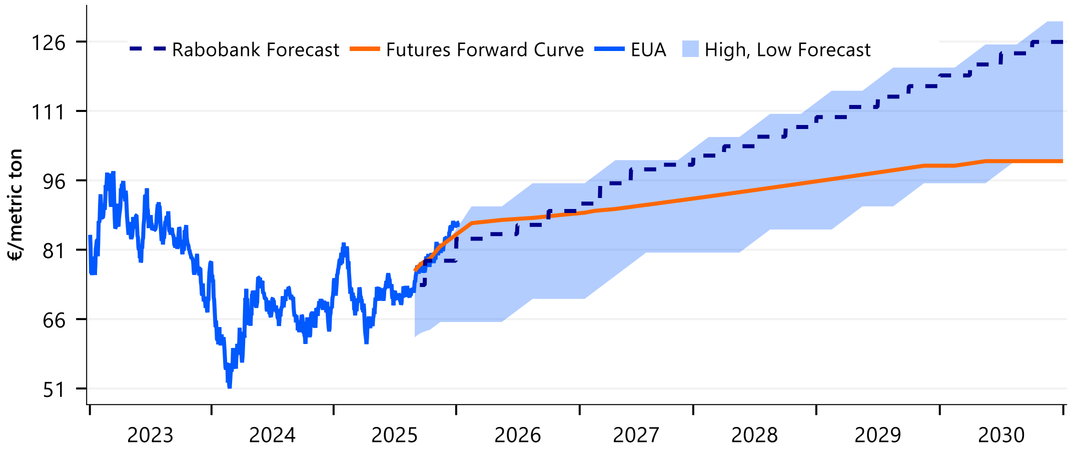
On supply, 2026 is the year when multiple tightening policies bite simultaneously:

- The total preliminary number of allowances scheduled for auction in 2026 is at about 531 million allowances – a 10% reduction from 2025 levels, BNEF data shows. This includes permits allocated to the aviation sector and allowances front-loaded from 2027-2030 through the REPowerEU initiative. The final auction volume remains subject to adjustments through the EU's Market Stability Reserve (MSR) in 2026.

- The 2023-2026 front loading of EUAs to raise €20bn for REPowerEU has added short term supply but we expect a tightening once this front loading ceases after 2026, removing that extra stream from auction calendars and supporting prices.

The combination of CBAM's definitive regime, the phase down in free allocation, and the end of REPowerEU front loading materially tightens the supply–demand balance. At the same time, lower fuel and power prices should modestly lift utilization and hedging needs in the power and industrial sectors versus 2023–2025. We forecast carbon prices to rise to €86/t CO_2e in 2026 and to above €90/t CO_2e in 2027 on the back of falling supply and growing compliance coverage (aviation free allocation removal, full maritime), even if positioning risks and competitiveness debates introduce more volatility.

Figure 9: We forecast European carbon prices to rise above €90/t CO2e by 2027.



Source: Bloomberg, RaboResearch 2026

Rabobank Price Forecasts

Crude Oil			Q1 26	Q2 26	Q3 26	Q4 26	Q1 27	Q2 27	Q3 27	Q4 27
Brent		Forecast	60.00	57.00	57.00	59.00	60.00	61.50	62.50	63.00
	$/BBL	Forward	61.56	61.01	60.87	60.84	60.94	61.15	61.69	62.04
WTI		Forecast	56.00	53.50	53.50	55.50	56.50	58.00	59.00	59.50
	$/BBL	Forward	57.61	57.48	57.39	57.26	57.28	57.52	57.98	58.30
NY ULSD		Forecast	2.12	2.06	2.06	2.11	2.13	2.17	2.19	2.20
	$/GAL	Forward	2.11	2.07	2.07	2.08	2.08	2.06	2.07	2.08
Gulf Coast Diesel		Forecast	2.06	2.00	2.00	2.02	2.05	2.10	2.12	2.10
	$/GAL	Forward	2.05	2.01	2.01	1.99	1.99	1.99	2.00	1.97
DOE On-Highway Diesel		Forecast	3.56	3.51	3.51	3.53	3.56	3.61	3.63	3.60
	$/GAL	Forward	3.55	3.52	3.52	3.50	3.50	3.50	3.51	3.48
ICE Gasoil		Forecast	618.35	599.73	599.73	609.04	610.90	625.80	633.25	635.11
	$/MT	Forward	606.84	596.63	593.91	590.31	588.45	588.52	597.03	597.36
RBOB		Forecast	1.74	1.92	1.86	1.69	1.68	1.93	1.91	1.73
	$/GAL	Forward	1.85	2.00	1.87	1.70	1.77	1.90	1.81	1.68
Natural Gas										
HH Natural Gas		Forecast	3.50	2.85	3.15	4.20	4.60	3.05	3.25	4.55
	$/MMBtu	Forward	3.00	3.18	3.50	4.17	3.59	3.44	3.62	3.96
TTF Natural Gas		Forecast	27.00	26.00	27.50	29.50	27.00	24.00	25.00	29.00
	€/MWh	Forward	27.15	26.09	26.33	26.97	25.88	23.53	28.18	29.52
NBP Natural Gas		Forecast	69.15	62.67	66.35	78.11	71.11	58.34	50.68	66.44
	GBp/Therm	Forward	67.53	62.88	63.53	69.59	66.24	57.19	57.13	65.60
JKM Natural Gas		Forecast	9.14	9.10	9.71	10.54	9.31	8.62	7.52	8.90
	$/MMBtu	Forward	9.19	9.13	9.32	9.67	8.93	8.46	8.61	9.08
Power										
German Baseload Power		Forecast	84.50	66.50	72.50	93.25	101.25	72.00	68.75	94.25
	€/MWh	Forward	94.09	72.17	81.27	93.99	94.06	67.84	76.72	92.20
Dutch Baseload Power		Forecast	82.81	65.17	71.05	91.39	99.23	70.56	67.38	92.37
Spanish Baseload Power		Forecast	90.12	69.92	74.65	88.60	90.66	65.29	72.19	85.37
UK Baseload Power		Forecast	58.08	45.70	62.29	73.95	71.74	51.01	60.89	77.05
	£/MWh	Forward	76.69	69.49	73.58	86.62	78.86	64.70	56.21	73.68
Carbon										
EUAs		Forecast	85.00	84.00	86.00	89.00	90.60	95.00	98.00	99.00
	€/MT	Forward	86.45	87.15	87.59	88.30	88.92	89.50	90.40	91.30

RaboResearch
Global Economics & Markets
mr.rabobank.com

Global Head

Jan Lambregts
+44 20 7664 9669
Jan.Lambregts@Rabobank.com

Macro Strategy

Global

Michael Every
Senior Macro Strategist
Michael.Every@Rabobank.com

Europe

Elwin de Groot
Head Macro Strategy
Eurozone, ECB
+31 30 712 1322
Elwin.de.Groot@Rabobank.com

Bas van Geffen
Senior Macro Strategist
ECB, Eurozone
+31 30 712 1046
Bas.van.Geffen@Rabobank.com

Stefan Koopman
Senior Macro Strategist
UK, Eurozone
+31 30 712 1328
Stefan.Koopman@Rabobank.com

Maartje Wijffelaars
Senior Economist
Italy, Spain, Eurozone
+31 88 721 8329
Maartje.Wijffelaars@Rabobank.nl

Leander Kalff
Macro Strategist
+31 88 723 8742
Leander.Kalff@Rabobank.nl

Americas

Philip Marey
Senior Macro Strategist
United States, Fed
+31 30 712 1437
Philip.Marey@Rabobank.com

Christian Lawrence
Head of Cross-Asset Strategy
Canada, Mexico
+1 212 808 6923
Christian.Lawrence@Rabobank.com

Mauricio Une
Senior Macro Strategist
Brazil, Chile, Peru
+55 11 5503 7347
Mauricio.Une@Rabobank.com

Renan Alves
Macro Strategist
Brazil
+55 11 5503 7288
Renan.Alves@Rabobank.com

Molly Schwartz
Cross-Asset Strategist
+1 516 640 7372
Molly.Schwartz@Rabobank.com

Asia, Australia & New Zealand

Teeuwe Mevissen
Senior Macro Strategist
China
+31 30 712 1509
Teeuwe.Mevissen@Rabobank.com

Benjamin Picton
Senior Macro Strategist
Australia, New Zealand
+61 2 8115 3123
Benjamin.Picton@Rabobank.com

FX Strategy

Jane Foley
Head FX Strategy
G10 FX
+44 20 7809 4776
Jane.Foley@Rabobank.com

Credit Strategy & Regulation

Matt Cairns
Head Credit Strategy & Regulation
Covered Bonds, SSAs
+44 20 7664 9502
Matt.Cairns@Rabobank.com

Bas van Zanden
Senior Analyst
Pension funds, Regulation
+31 30 712 1869
Bas.van.Zanden@Rabobank.com

Cas Bonsema
Senior Analyst
Financials
+31 6 127 66 642
Cas.Bonsema@Rabobank.com

Maartje Schriever
Analyst
ABS
+31 6 251 43 873
Maartje.Schriever@Rabobank.com

Lyn Graham-Taylor
Senior Rates Strategist
+44 20 7664 9732
Lyn.Graham-Taylor@Rabobank.com

Agri Commodity Markets

Carlos Mera
Head of ACMR
+44 20 7664 9512
Carlos.Mera@Rabobank.com

Charles Hart
Senior Commodity Analyst
+44 20 7809 4245
Charles.Hart@Rabobank.com

Oran van Dort
Commodity Analyst
+31 6 423 80 964
Oran.van.Dort@Rabobank.com

Andrick Payen
RaboResearch Analyst
+1 212 808 6808
Andrick.Payen@Rabobank.com

Energy Markets

Joe DeLaura
Senior Energy Strategist
+1 929 697 5584
Joe.DeLaura@Rabobank.com

Florence Schmit
Senior Energy Strategist
+44 20 7809 3832
Florence.Schmit@Rabobank.com

Client coverage

Wholesale Corporate Clients

Martijn Sorber	Global Head	+31 30 712 3578	Martijn.Sorber@Rabobank.com
Hans Deusing	Europe	+31 30 216 9045	Hans.Deusing@Rabobank.com
Neil Williamson	North America	+1 212 808 6966	Neil.Williamson@Rabobank.com
Adam Vanderstelt	Australia, New Zealand	+61 2 8115 3102	Adam.Vanderstelt@rabobank.com
Ethan Sheng	Asia	+852 2103 2688	Ethan.Sheng@Rabobank.com
Ricardo Rosa	Brazil	+55 11 5503 7150	Ricardo.Rosa@Rabobank.com

Financial Institutions

Short-term Interest Rates

Marcel de Bever	Global Head	+31 30 216 9740	Marcel.de.Bever@Rabobank.com

Bonds & Interest Rate Derivatives

Henk Rozendaal	Global Head Fixed Income	+31 30 216 9423	Henk.Rozendaal@Rabobank.com

Solutions

Sjoerd van Peer	Global Head	+31 30 216 9072	Sjoerd.van.Peer@Rabobank.com

Relationship Management

Rogier Everwijn	Global Head	+31 30 712 2440	Rogier.Everwijn@Rabobank.com
Rob Eilering	Banks	+31 30 712 2162	Rob.Eilering@Rabobank.com
Petra Schuchard	Insurers		Petra.Schuchard@Rabobank.com
Frank Dekkers	Asset Managers		Frank.Dekkers@Rabobank.com
Javier Alvarez de Eerens	MDB	+31 30 712 1015	Javier.Alvarez@Rabobank.com
Christel Kleinhaarhuis	Fintech		Christel.Klein.Haarhuis@Rabobank.com

Capital Markets

Laura Bijl	Global Head	+31 88 726 3254	Laura.Bijl@Rabobank.com
Christopher Hartofilis	Capital Markets USA	+1 212 808 6890	Christopher.Hartofilis@Rabobank.com
Joicy Dinh	Capital Markets Asia	+852 2103 2613	Joicy.Dinh@Rabobank.com
Adriana Gouveia	Capital Markets Brazil	+55 11 5503 7305	Adriana.Gouveia@rabobank.com
Willem Kröner	Global Head ECM	+31 30 712 4783	Willem.Kroner@Rabobank.com
Harman Dhami	DCM Syndicate	+44 20 7664 9738	Harman.Dhami@Rabobank.com
Crispijn Kooijmans	DCM FIs & SSAs	+31 30 216 9028	Crispijn.Kooijmans@Rabobank.com
Bjorn Alink	DCM Securitisation & Covered Bonds	+31 30 216 9393	Bjorn.Alink@Rabobank.com
Othmar ter Waarbeek	DCM Corporate Bonds	+31 30 216 9022	Othmar.ter.Waarbeek@Rabobank.com
Joris Reijnders	DCM Corporate Loans	+31 30 216 9510	Joris.Reijnders@Rabobank.com
Brian Percival	DCM Leveraged Finance	+44 20 7809 3156	Brian.Percival@Rabobank.com

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A summary of the methodologies used by Rabobank can be found on our website.

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