S&P Global
Commodity Insights

Europe, CIS and Africa Crude and Condensate Outlook

Annual Strategic Workbook 2025

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ASW 2025 release notes and enhancements

- **Important release notes**
  - This forecast incorporates S&P Global Commodity Insights analysis for 2025-2026 as presented in the **April Short-Term Outlook** updates for crude oil and refined products markets. Trade tariffs implemented on April 2 or later and the impacts on oil market fundamentals have not been incorporated into this forecast.

- **ASW 2025 Crude Oil Markets Enhancements**
  - Excel tables
    - Liquids supply and demand balance 1990-2050
    - Total crude oil and condensate crude balances for global, regions and key countries
  - PowerPoint decks
    - Regional trade, crude balances and pricing elements will be new sections

Data compiled April 25, 2025.
Source: S&P Global Commodity Insights

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Executive summary

Europe, CIS and Africa key insights

- **Russia’s invasion of Ukraine sets its upstream on a path of long-term decline**. In 2024, Russian production of crude and condensate fell by 3% to 10.25 million b/d. Although Russian production is holding up for now, we believe it will never recover to its previous output levels given all the new constraints and output is expected to decline steadily in the long-term. Investments focused on older fields in West Siberia for quicker returns, with exceptions like the delayed Vostok Oil project. Key uncertainties include potential production growth in West Siberia, development of overlooked areas, and contributions from Arctic projects. Aboveground factors such as investment climate and access to technology are crucial determinants of production.
- **Kazakhstan's crude and condensate production averaged 1.84 million b/d, below the 2019 peak of 1.90 million b/d.** Production is expected to exceed this figure in 2025, driven by the Tengiz Future Growth Project (FGP) expansion, which will add 260,000 b/d, increasing Tengiz production to over 870,000 b/d by 2028. Kashagan field production also rose in 2024, with further growth anticipated through minor debottlenecking. Karachaganak's output remains stable, exempt from OPEC+ restrictions. Kazakhstan is diversifying exports via the BTC pipeline, addressing reliance on the CPC pipeline and limited opportunities for increased exports to China (mainland).
- **Norway's production will plateau near-term but faces long-term decline without new exploration success.** Output is anchored by the Johan Sverdrup field, which accounted for nearly 40% of total production in 2024. New projects like Johan Castberg, Balder X, and Breidablikk will support near-term levels, but aging infrastructure, ESG pressures, and uncertain Barents Sea exploration results pose longer-term risks.
- **The UK faces steep declines from a maturing basin amid mounting regulatory and ESG challenges.** Production will fall significantly through 2050, with limited new exploration under the Labour government’s planned licensing halt. Despite strong existing infrastructure and opportunities for tiebacks, energy transition goals and co-location conflicts with CCS and offshore wind may further constrain future output.
- **The European oil market has undergone a profound shift since Russia, once supplying nearly 45% of the region's crude imports, was sidelined by EU sanctions following its invasion of Ukraine**. With bans on seaborne crude imports and later on refined products still in force, Europe's reliance on Russian oil has been dramatically reduced, driving the region to seek supplies from the US, the Middle East, and Africa. As a consequence, while European refinery runs are forecast to decline, Russian crude is being redirected primarily to Asian markets such as China (mainland) and India, along with remaining flows to Turkey and other non-OECD countries via pipelines that skirt shipping sanctions. Amid these developments, US exports to Europe are set to grow to about 2.8 million b/d by 2030, making up roughly 28% of European imports, whereas Middle Eastern volumes will account for around 11%.

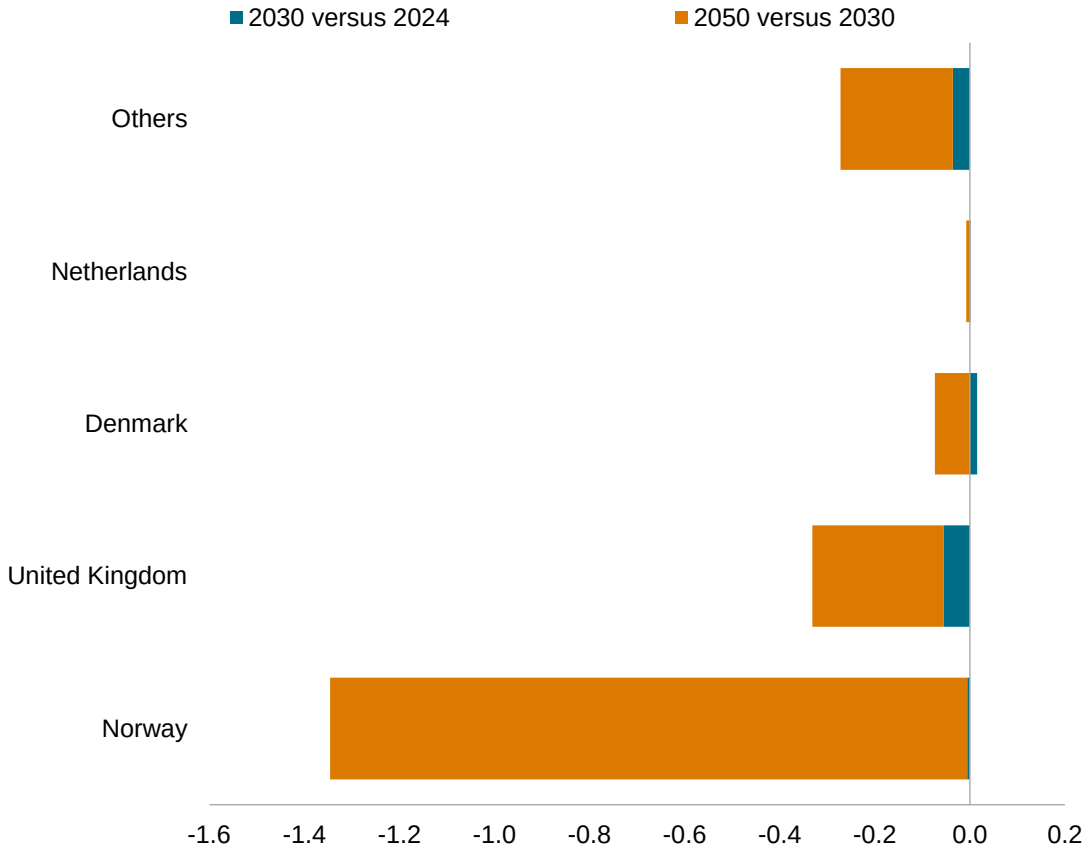
Europe, CIS and Africa key insights (continued)

- In North Africa, **Algeria’**s output averaged 1.11 million b/d, with projections to stabilize around 1 million b/d by 2030 as mature fields decline and incremental projects like Bir Seba (Phase 2) and Hassi Bir Rekaiz (Phase 2) modestly offset the downturn. **Egypt**, meanwhile, experienced a slight drop in production to about 537,000 b/d due to aging fields and limited new exploration, reflecting a broader trend of declining output despite ongoing development efforts.
- **Libya**’s oil production continues to be impacted by longstanding political and infrastructural challenges, and although intermittent recoveries have occurred, the country’s future output largely hinges on resolving political unrest and attracting much-needed infrastructural investments.
- **Angola** maintained stable production, averaging 1.1 million b/d, and is looking to upcoming projects such as Agogo Phase 3 and the Ndungu development to sustain output amid the long-term decline of its mature fields. **Nigeria**’s production reached approximately 1.55 million b/d, overcoming challenges like oil theft and infrastructure issues. With fresh investments in deepwater projects such as Shell’s Bonga North and indigenous participation, the outlook is cautiously optimistic for future growth.
- In the **Republic of Congo**, efforts are underway to boost output from key fields like Moho Nord, even as forecasts rely on continued investment in redevelopment and new projects. **Ghana** remains a focal point with production driven primarily by Tullow Oil’s Jubilee field, and prospects for additional growth are linked to the development of deepwater discoveries.
- Meanwhile, **Namibia** has a relatively brief history in oil production marked by recent discoveries that have sparked investor interest, and its future potential appears promising as exploratory successes may eventually lead to a production peak around 2035. **Cameroon**’s production history has been constrained by mature fields that have led to a steady decline since 2020, and without significant new investments, the outlook suggests continued challenges in maintaining current output levels. Elsewhere, **Kenya** is on the brink of its first oil production via Tullow Oil’s Lokichar project, while **Côte d'Ivoire** has seen a significant rise in output driven by the Baleine field, underlining the continent’s varied advancement in oil and gas exploration and development.
- **Africa—already a net exporter of light, sweet crude—sees a mixed picture for trade**: West, North, and parts of Central Africa are major exporters, with intra-African trade rising due to new refining projects like the Dangote mega-refinery, which has a 650,000 b/d nameplate capacity and is expected to diversify its slate of imported crudes once fully operational. At the same time, Africa's overall export patterns are shifting with increased volumes directed to Asia, particularly as US shale growth rebounds and Asian domestic production wanes, leading China (mainland)'s share of African exports to exceed 50% by 2040. Limited investment is anticipated to constrain Russian production further—forecasted to drop by 1.6 million b/d between 2025 and 2035—while domestic refining capacity in Russia is expected to contract due to ageing infrastructure and margin pressures, fundamentally rewiring global oil trade flows.

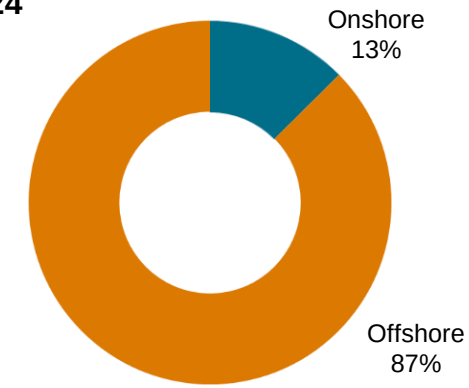
Crude supply

European production outlook dominated by diminishing North Sea production declines from Norway and United Kingdom

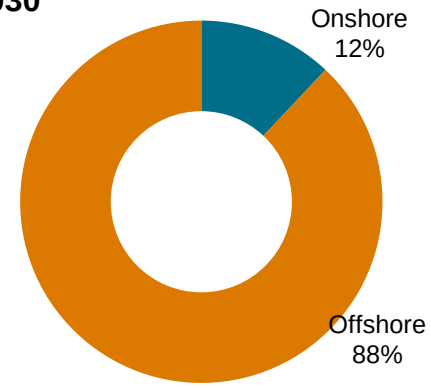
Europe crude oil production changes (million b/d)



European terrain in 2024



European terrain in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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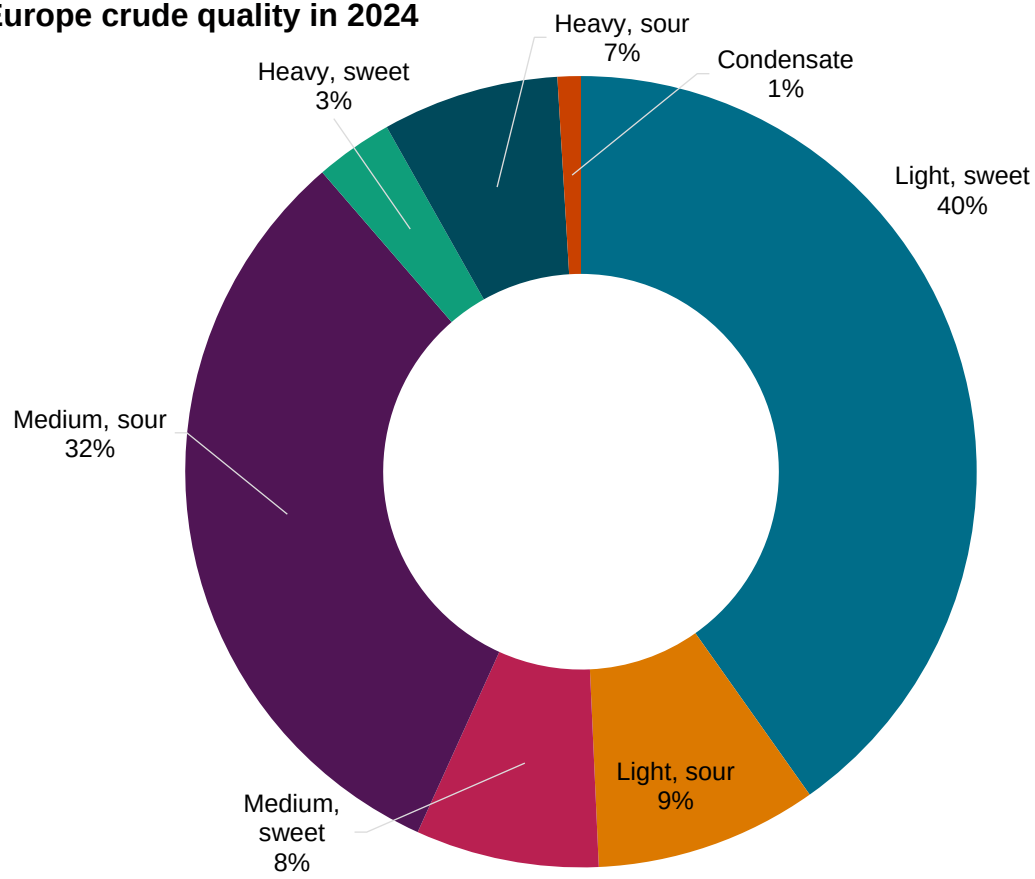
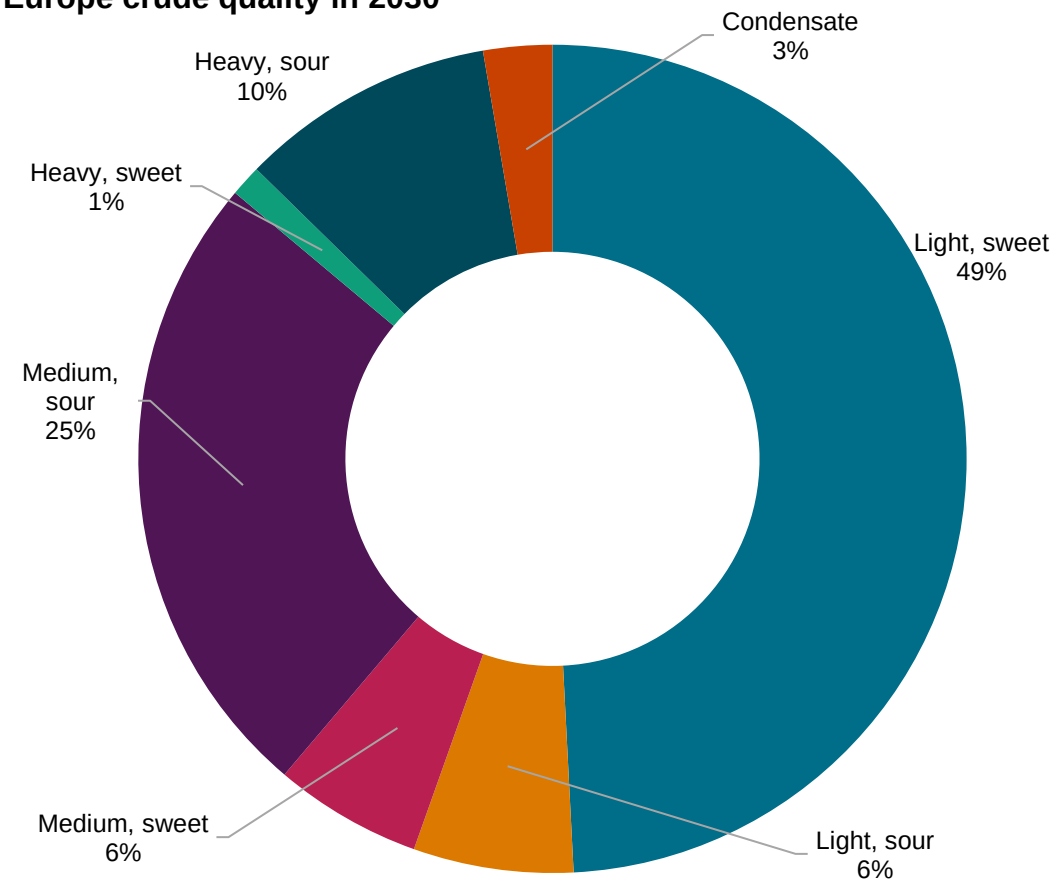
European medium sours in the European crude slate is expected to decline post 2025 as Johan Sverdrup output declines from its peak

Europe crude quality in 2024



Europe crude quality in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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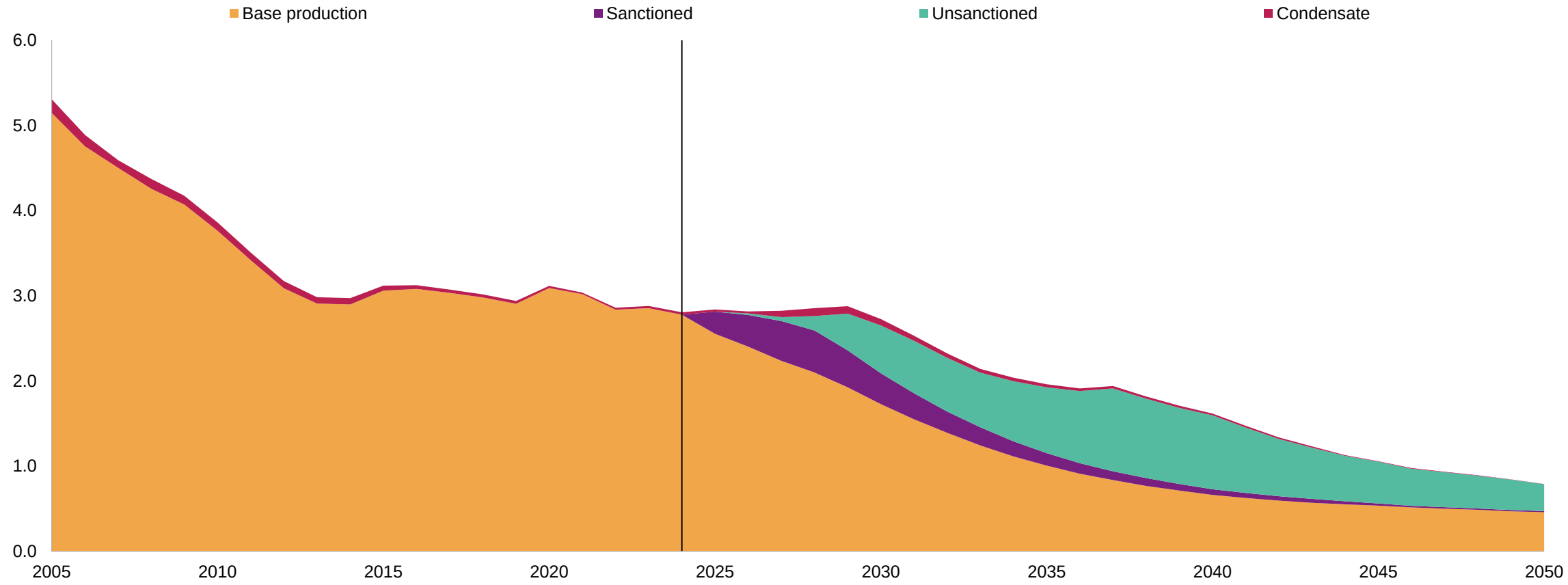
European crude and condensate production by major countries

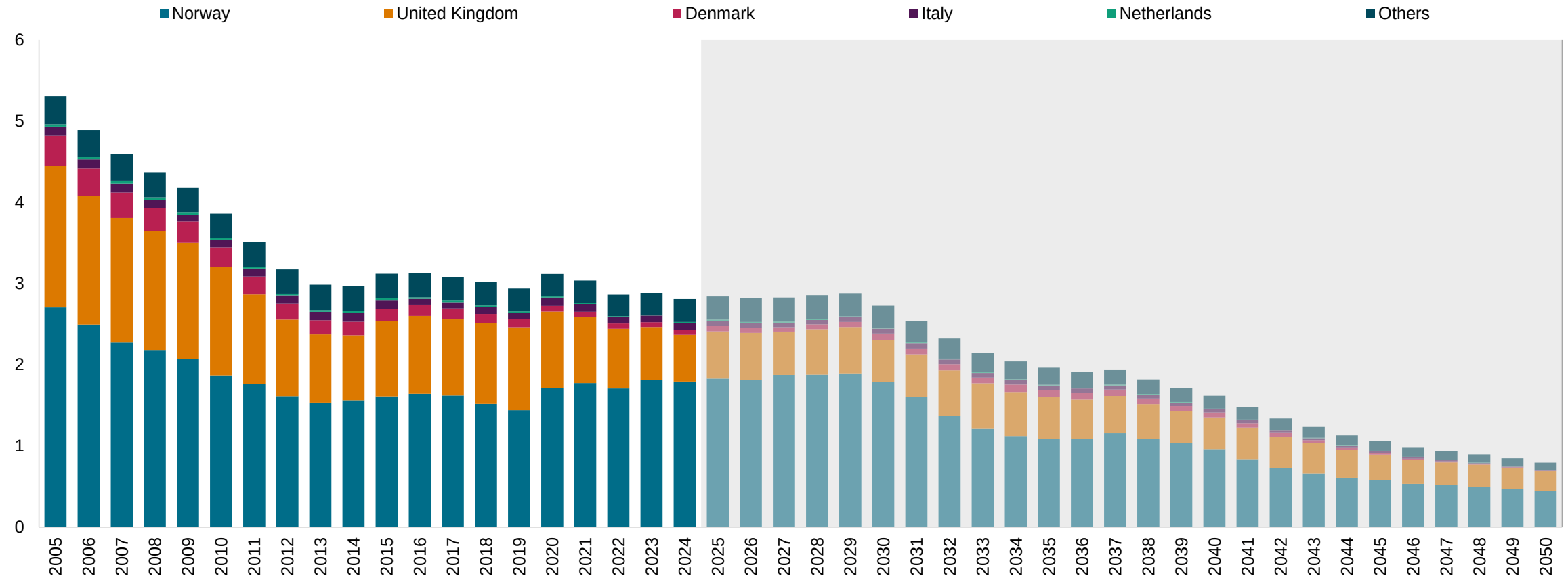
Europe's crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

European crude and condensate production by major countries

Major European oil producers (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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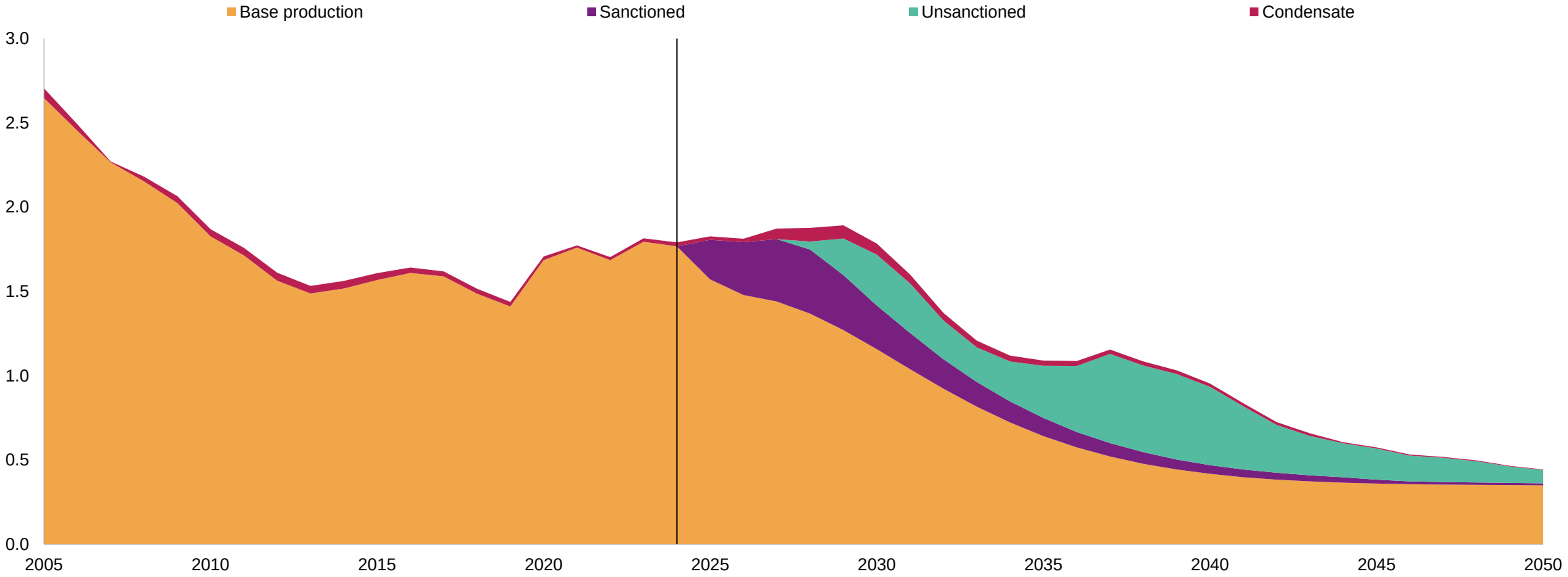
Norway’s production is anticipated to be bolstered by the addition of several small projects, such as Johan Castberg and Balder X, before a long-term decline begins

Norway crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

Norway key messages

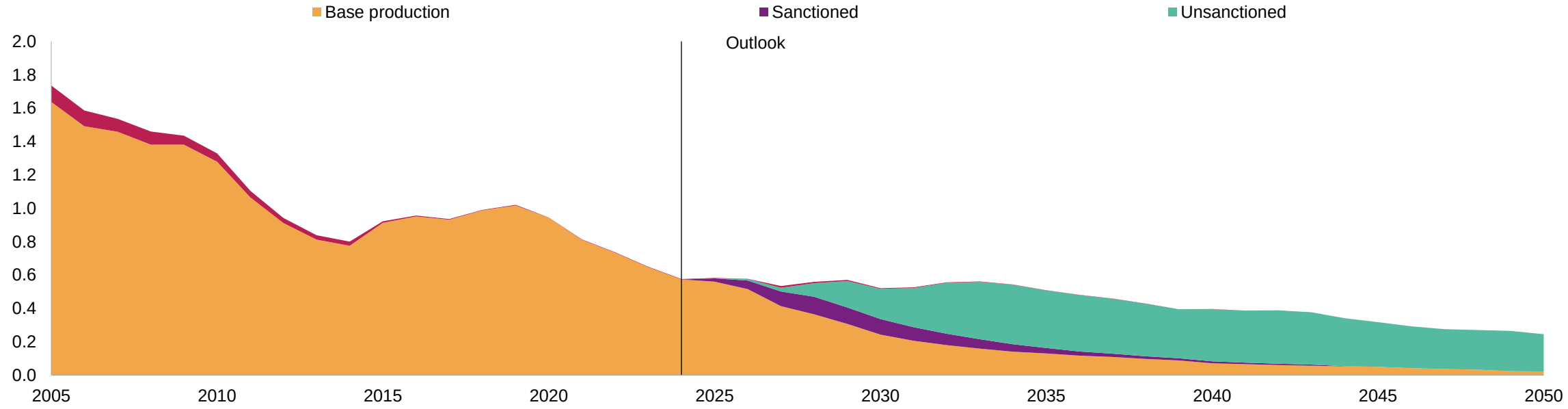
Norwegian crude and condensate decreased marginally to 1.79 million b/d in 2024. Condensate output accounted for just 22,000 b/d of total output.

- Norway's production in the North Sea relies heavily on production from its giant Johan Sverdrup field. Phase 2 of Johan Sverdrup, which began production in December 2022, has been the main source of increased production in recent years. The output from the field averaged 711,000 b/d in 2024 and we anticipate that the output will fall to around 670,000 b/d in 2025 before falling at a faster pace beyond that.
- Johan Sverdrup output accounted for close to 40% of Norway's total crude and condensate production in 2024. Several production increases have been achieved at Johan Sverdrup since the field came onstream in October 2019. The increases were possible due to high and stable production levels, which exceeded expectations from the outset. Equinor and its partners decided on the increased capacity after testing the plant capacity at the end of 2020 to verify a possible production rise. After making the concept selection for Johan Sverdrup Phase III in December 2024, Equinor is now working towards the final investment decision, due in the second quarter of 2025., with start-up targeted for late 2027 early 2028.
- Norway's third field in the Barents Sea has been brought on stream and is ramping up towards its planned peak production of 220,000 b/d in 2026. Equinor announced first oil from the Johan Castberg field on March 31, 2025 and expects to recover 450-650 million barrels of oil over the 30-year lifespan of the field. The development has seen a series of delays and adjustments to its capital expenditure.
- Balder X project production is expected to commence by the end of the second quarter of 2025, with oil production anticipated to peak in approximately three to four months post-startup. Production is expected to average around 75,000 b/d in 2025.
- Additionally, the Breidablikk project, a subsea tieback to the Grane, which began production in the fourth quarter of 2023, added approximately 52,000 b/d to Norwegian output by in 2024. Production is expected to peak at 57,000 in 2025.
- The mature Norwegian Continental Shelf (NCS) is experiencing declining oil production, but the country's operators are prepared to continue investing in extending the life of its oil and gas sector, even while the authorities impose more stringent measures to reduce carbon emissions. Norwegian oil exports meet about 2% of global consumption and the country is expected to remain a critical supplier for neighboring European countries in the decades to come.
- Norway's resource base is expected to keep output at 1.83 million b/d through 2025. Beyond this point, base production is expected to decline more rapidly, but output to platue close to 1.8 million b/d, supported by production from sanctioned projects. Norway's ability to arrest declines will depend largely on the exploration success in the next few years, especially in the Barents Sea. New exploration licensing rounds and development sanctioning of new oil and gas projects are now increasingly subject to challenge via environmental, social, and governance (ESG)–related popular sentiments and litigations. Future supply from Norway is expected to be a mixture of new fields and frontier fields.

Data compiled: May 2025.
Source: S&P Global Commodity Insights.

UK output declines for the fourth consecutive year, but sanctioned projects expected to provide short-term pause in decline

United Kingdom crude and condensate production by development (million b/d)



- Several small projects are expected to temporarily halt the decline in UK output after production decreased by approximately 79,000 b/d in 2024, averaging 634,000 b/d. Production from the Central Graben, Moray Firth Province, West Shetlands, and Faroes-Shetland Trough basins will help the pause in the decline.
- Shell's Penguins in the northern Viki is a notable source of crude addition in 2025. Production from the Penguins redevelopment project is expected to peak at around 30,000 b/d in 2026, from approximately 100 MMboe of recoverable resources. Oil is to be exported by tanker from the FPSO and gas by pipeline to the St Fergus terminal in Scotland.

Data compiled: May 2025.
Source: S&P Global Commodity Insights.

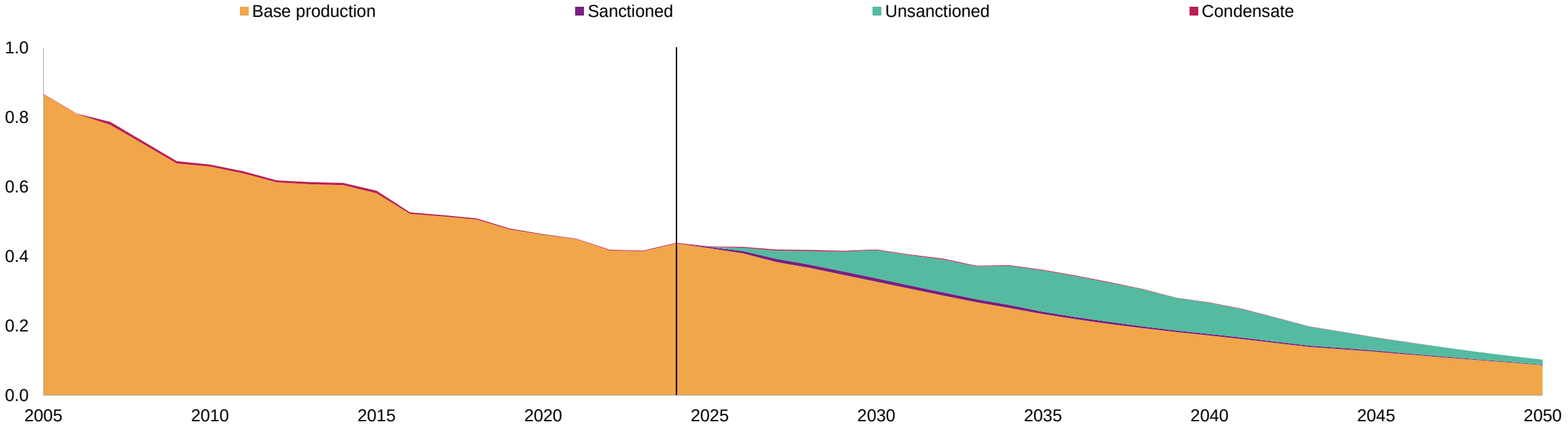
UK key messages

- After peaking in 1999, production has been in decline up to now, and will average around 550,000 b/d over the next ten years. The country has a mature petroleum province that has historically benefited from a supportive government and stable fiscal regime. Since 2022, fiscal instability and low confidence in the government's support for industry has deterred investment in oil and gas exploration, appraisal and development. Exploration and development is mostly focused on the larger fields already in production, where infrastructure exists with capacity to receive oil and gas from satellite fields. The West of Shetland and the Mid North Sea High are the exception, where large finds could justify stand-alone developments.
- Significant offshore infrastructure has been constructed over approximately 60 years, and hubs can often be extended through low-cost tiebacks of satellite fields, which delay cessation of production (COP) of the hubs, limiting UK production declines.
- As part of the country’s energy transition, the UK North Sea is increasingly becoming an integrated energy basin and many of the petroleum industry's operators are transforming into integrated energy companies.
- Due to the UK being a mature province, the geology and petroleum systems are well understood, exploration is based on vast data resources and many of the larger fields are reaching the end of their economic lives. The increasing offshore acreage designated for wind and planned carbon capture and storage (CCS) projects presents potential co-location challenges for oil and gas exploration and development. However, at the end of a field's life, certain oil and gas infrastructure can be repurposed for energy transition initiatives in CCS, thereby lowering costs for the CCS sector.
- The Labour government, appointed in July 2024, plans to halt the award of new exploration or development licenses over currently unlicensed blocks. License extensions will be granted for the term, duration, or phase of an existing license. The regulatory change will not prevent the award of carbon storage, gas storage and methane drainage licenses. There are farm-in opportunities available in either exploration, small field developments as tiebacks to hubs and large stand-alone developments (e.g., Ithaca Energy's Cambo field).
- Above ground risks will continue to be a major factor effecting investment decisions. The requirement for electrification of facilities will impact field economics and delays from other regulatory changes (e.g., the 'Finch' case ruling) will be a consideration before investment is committed.
- Our current forecast is for crude and condensate production to decline by around 330,000 b/d to 2050, reaching just 245,000 b/d. This is a major decrease compared to highs of over 2 million b/d before peak production in the 1990s.

Data compiled: May 2025.
Source: S&P Global Commodity Insights.

Other European countries key messages

Europe's crude and condensate production by development (million b/d)

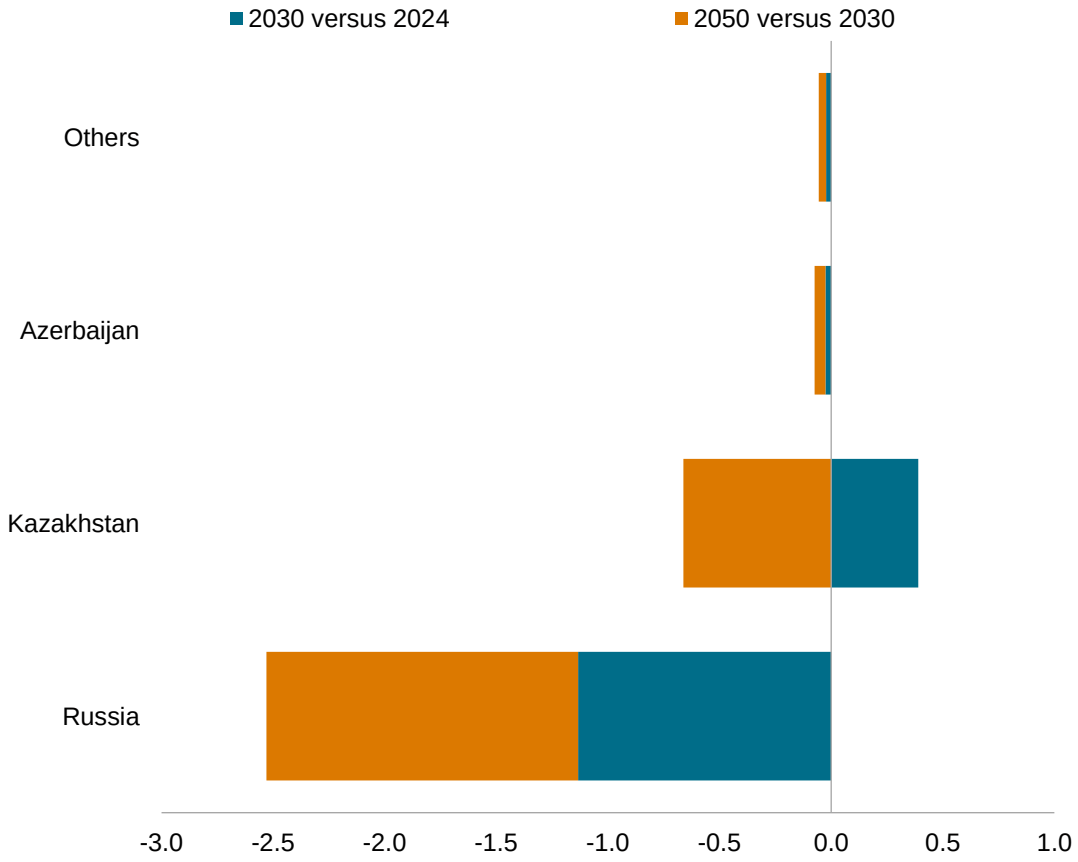


- Elsewhere in Europe, crude oil production is limited and largely declining. In general, new discoveries are only slowing the existing decline rates and the discovery of significant new resources will be required to improve the outlook in the mid-to-long term.
  - Outside of the United Kingdom and Norway, some of the larger projects that are expected to start production in Europe are mostly in Denmark. On April 26, 2024, the Danish Energy Agency (DEA) announced that it had approved the revised plans for the expansion and production of the INEOS-operated Hejre HP/HT oil and gas field. The Hejre project is expected to start in 2029 and will increase to about 20,000 b/d at its peak.

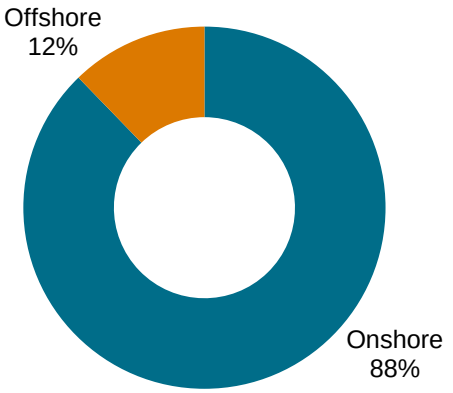
Data compiled: May 2025.
Source: S&P Global Commodity Insights.

Russia’s decline pulls CIS output lower over the next decade, as Kazakhstan ramps up production

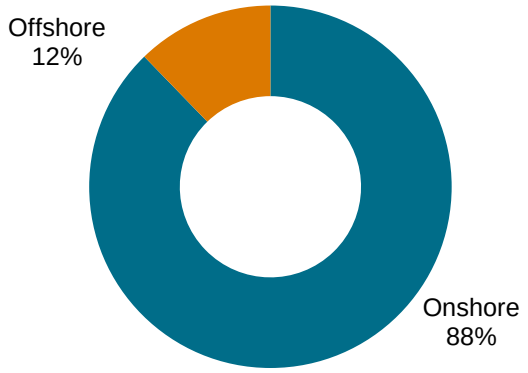
CIS crude oil production changes (million b/d)



CIS terrain in 2024



CIS terrain in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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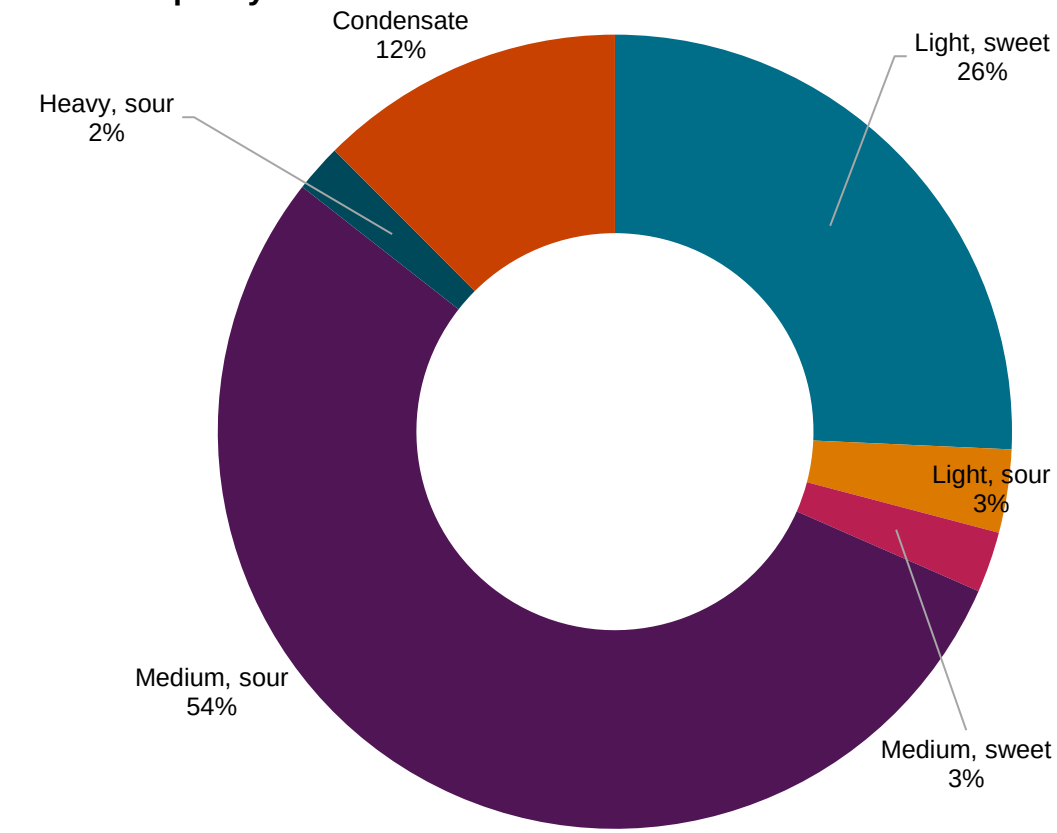
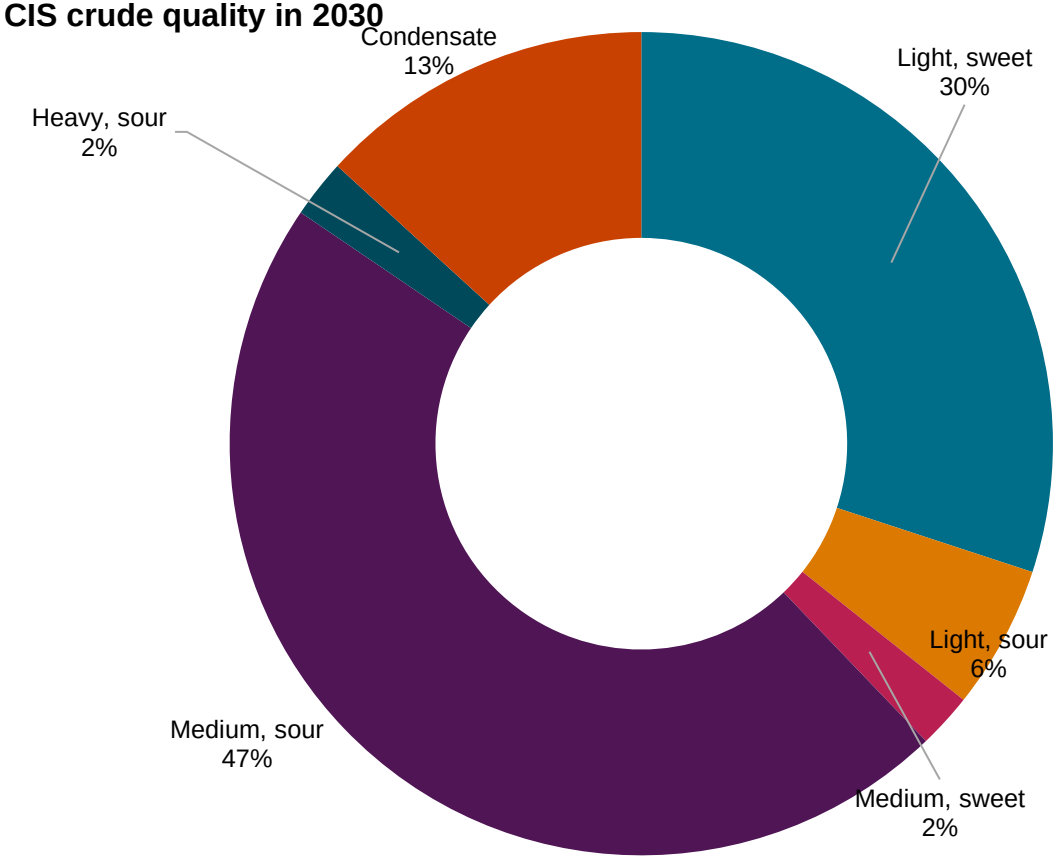
CIS crude quality shifts marginally toward lighter and sweeter crudes as Russian output declines

CIS crude quality in 2024



CIS crude quality in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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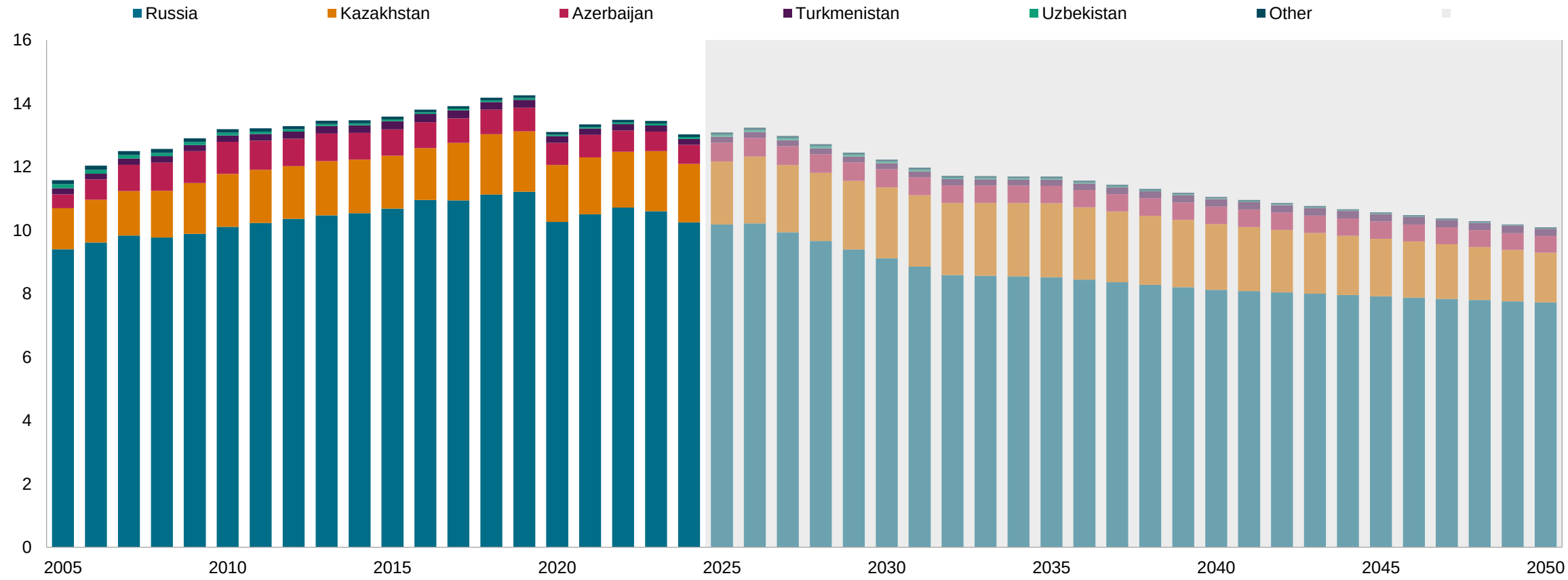
CIS crude and condensate production by major countries

Major CIS oil producers (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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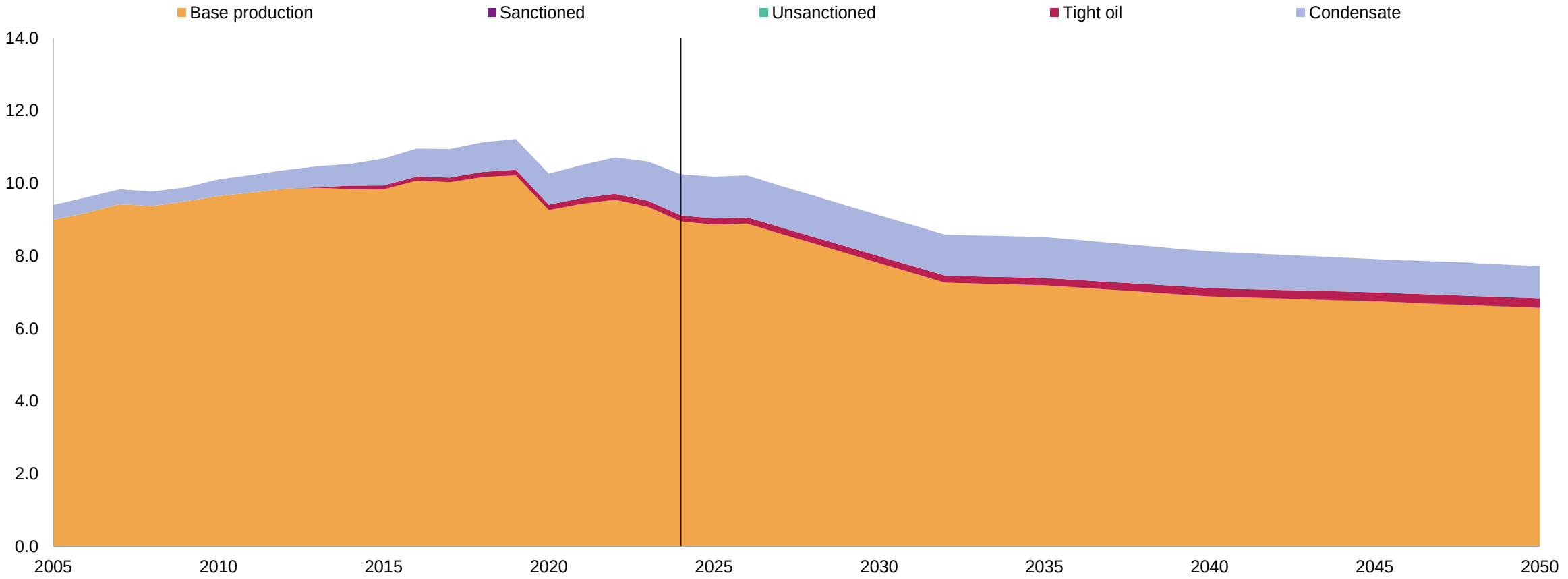
Russia’s production expected to remain flat in 2025 and 2026 before resuming its decline as sanctions limit investment in the upstream sector

Russia crude and condensate production by development (million b/d)

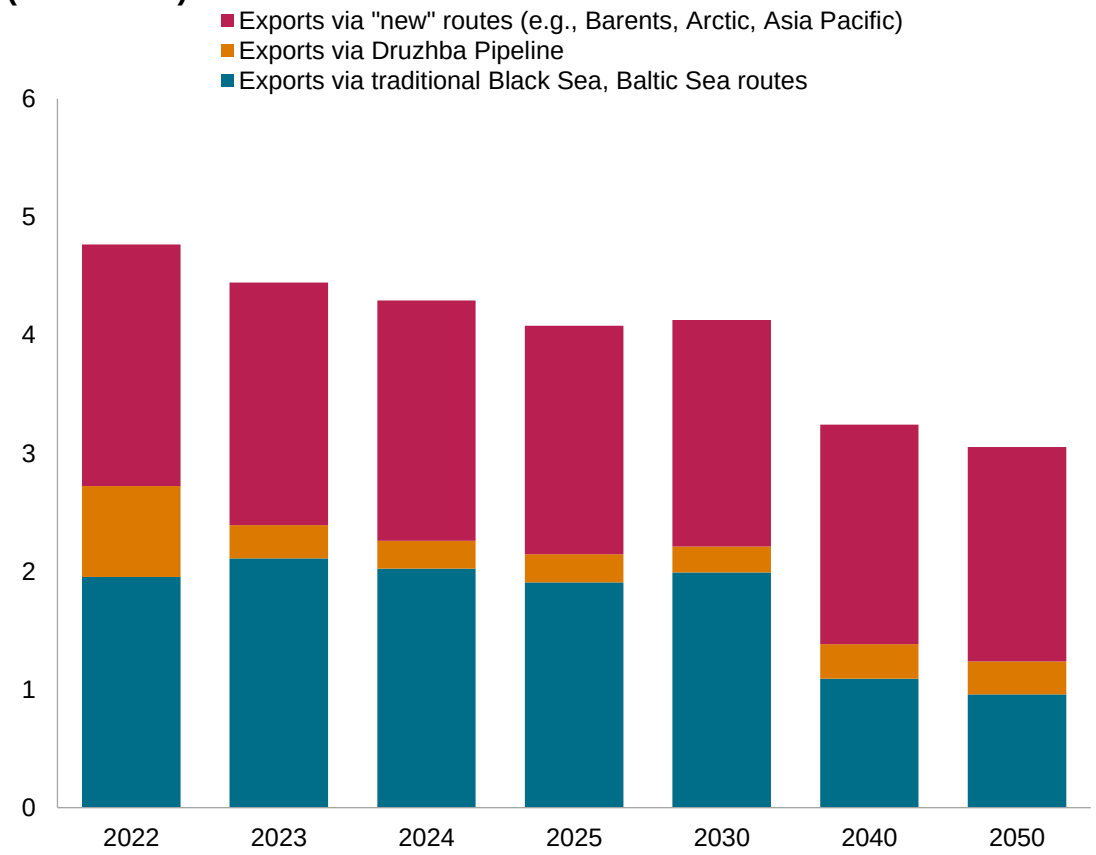


Data compiled: May 2025.
Source: S&P Global Commodity Insights.

The 2024 drop in Russian oil production reflected deeper voluntary OPEC+ cuts, while planned output recovery in 2025 appears problematic

- Russian oil (crude plus condensate) production fell by 3.0% to 10.25 million b/d in 2024.
  - Crude output fell by 3.7% to 9.1 million b/d, as Russia's voluntary OPEC+ cuts lowered production to just under 9.0 million b/d on a monthly basis starting in August 2024.
  - Russia has pledged to compensate for some overproduction during part of 2024 by June 2026, but the bigger challenge will come with the planned unwinding of about 470,000 b/d of voluntary cuts during 2025–26 within the OPEC+ framework if and when OPEC+ initiates a production increase.
  - Condensate output grew by 4.5% in 2024 to 1.13 million b/d, with condensate's share of overall Russian oil production edging up from 8.7% in 2023 to 9.4% in 2024.
  - Condensate output growth has been supported by ongoing development of wetter Russian gas reserves and an uptick in overall Russian gas production in 2024 following two years of decline.
- Key indicators suggest that Russian oil companies focused their upstream investment in 2024 on older acreage yielding relatively quick returns, primarily in West Siberia, rather than on generally costlier new field projects, with a few key exceptions.
  - In December 2024, Rosneft announced a two-year delay in launching the initial phase of its Vostok Oil project in the Russian Arctic, which is the largest greenfield upstream venture in the Russian oil industry.

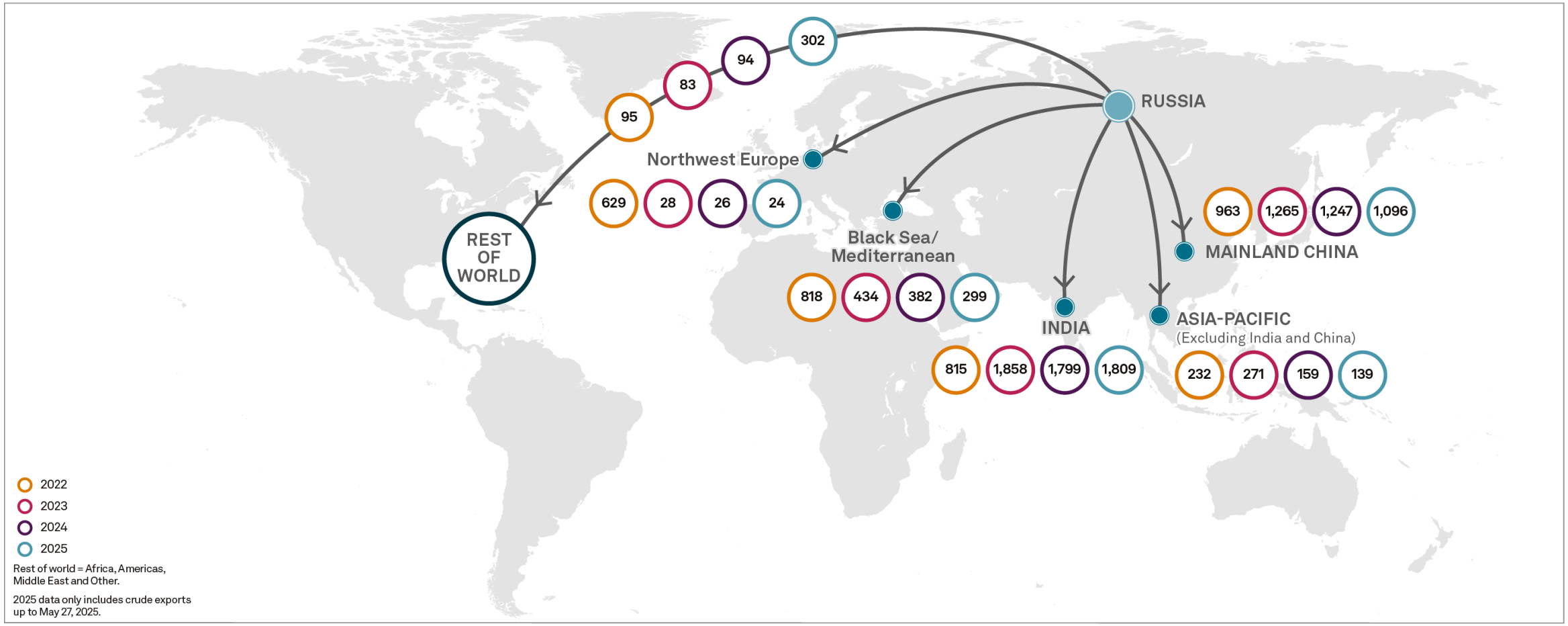
Distribution of Russian non-CIS crude oil exports by major routes (million b/d)



Data compiled: May 2025.
For a more detailed outlook see Eurasian Oil Export Outlook
Source: S&P Global Commodity Insights.

Eastward reorientation of Russia's crude oil exports continued in 2024

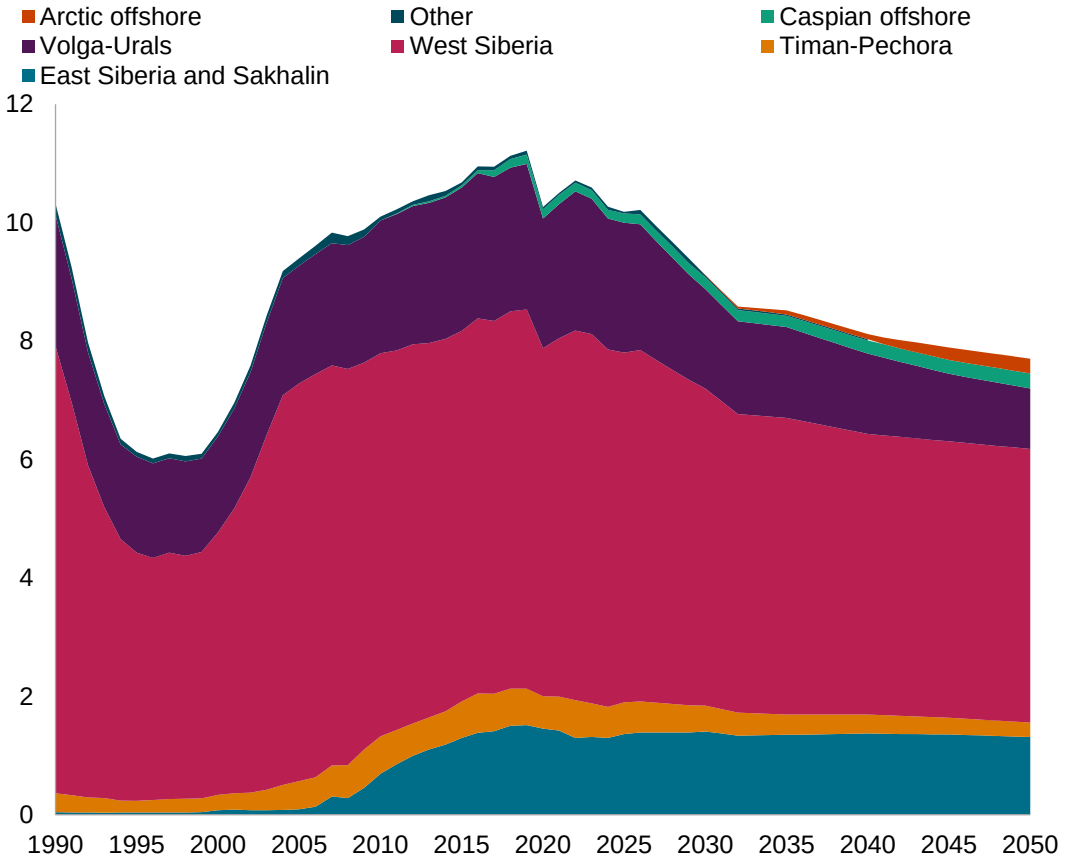
Russian seaborne crude oil exports (thousand b/d)



Data compiled May 27, 2025.
Source: S&P Global Commodity Insights: IC-251058-01.

Russian outlook remains highly uncertain due to potential production growth challenges, investment and regulatory factors

Regional composition of Russian oil production (million b/d)

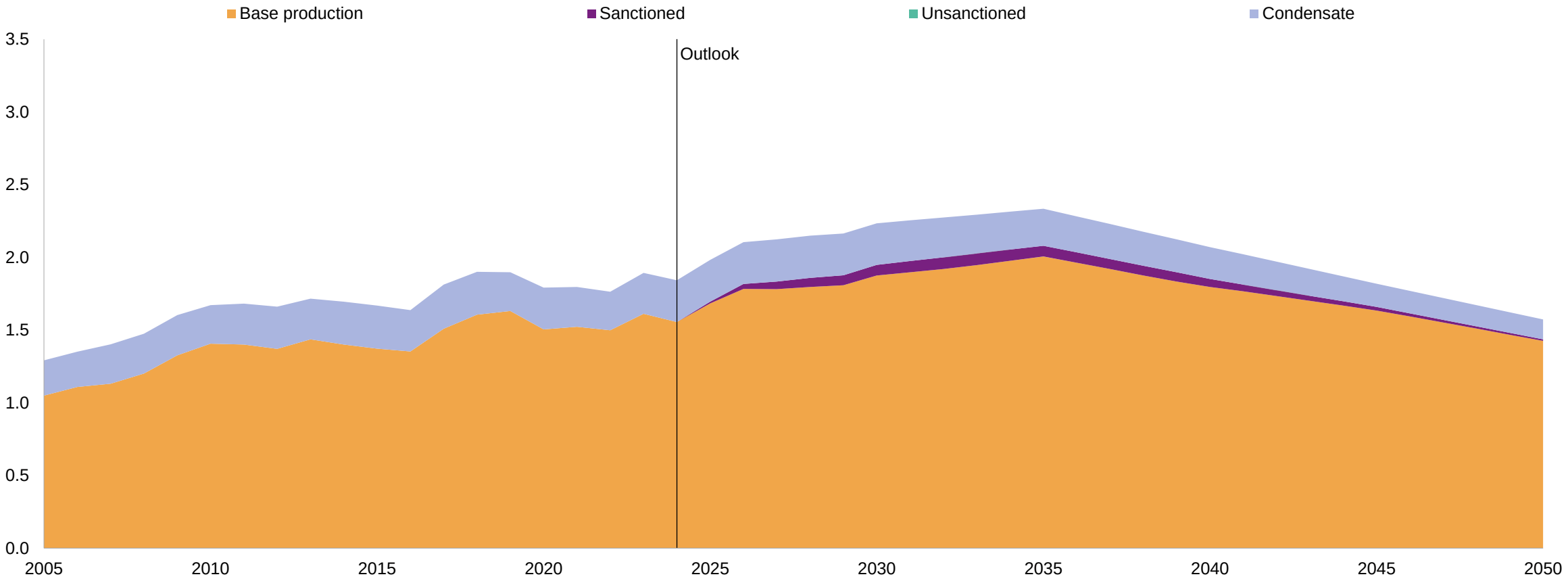


Data compiled: May 2025.
For a more detailed outlook see Eurasian Oil Export Outlook
Source: S&P Global Commodity Insights.

- There are several key areas of uncertainty in the Russian upstream sector:
  - The potential for production growth from West Siberia through the comprehensive application of modern practices and technologies on older fields already in production (and to what extent this can now be expected without the presence of international companies);
  - The potential for developments in West Siberia in deeper horizons and in parts of the basin previously overlooked (including so-called tight oil);
  - The general prospectivity and commerciality of a “second generation” or even “third generation” of smaller fields in inland East Siberia;
  - The potential for further attenuating the decline rate in mature fields and basins across Russia; and
  - The potential contribution from offshore (or near-coastal) Arctic developments over the longer term.
- Another factor complicating the production trajectory for Russian oil is that each of the seven large geographical divisions we use to categorize Russian oil production (the regional aggregations used are relevant for subsequent oil transportation and do not precisely correspond with geologically defined major producing basins) are, in fact, composites of production from diverse fields and projects.
- Furthermore, the key factors determining Russian oil production are basically “aboveground” rather than technical issues relating to reserves or fields; these factors are the overall investment climate, including global oil prices, tax policy, export access, access to foreign technology, transportation policies, and access to reserves by domestic and international companies, along with other, similar issues..

Kazakhstan’s megaprojects expected to push overall production to about 2.2 million b/d by mid 2020s

Kazakhstan crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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Kazakhstan: Big 3 fields and Future Growth Project at Tengiz push production higher over the next ten years

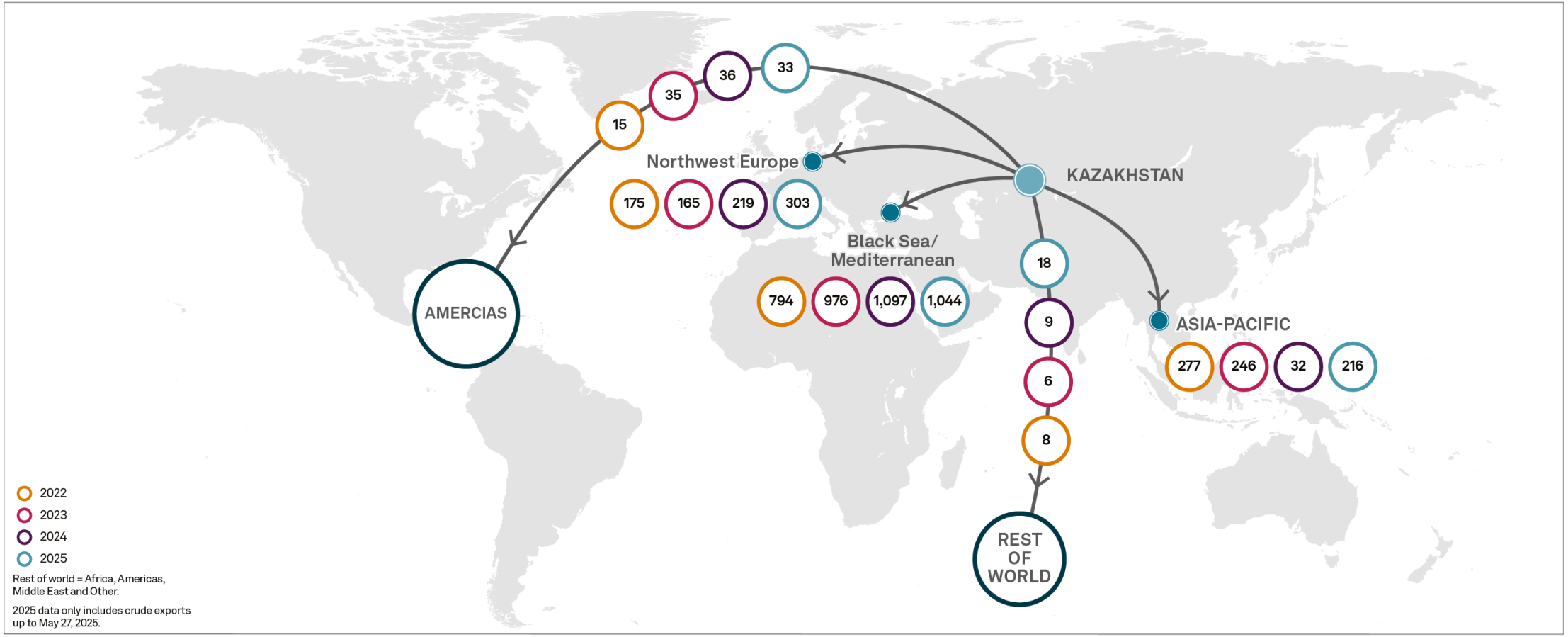
- Kazakhstan's crude and condensate production averaged 1.84 million b/d in 2024, remaining below the historical peak of 1.90 million b/d reached in 2019. Kazakhstan's oil production is projected to exceed the 2019 figure in 2025 and Tengiz's Future Growth Project (FGP) expansion is the main catalyst for this surge. The jump in Tengiz (and therefore in overall Kazakhstani) production the result of a sooner-than-expected startup of FGP. Kazakhstan's official plan still calls for output to rise to 2 million b/d in 2025 and then exceed 2 million b/d in 2026 and remain above that level through 2030. We envision national output reaching a maximum of 2.33 million b/d in 2035, followed by a subsequent slow decline in the base case.
- The main Kazakh developments driving the overall trend are three "mega" projects: Tengiz, Karachaganak, and Kashagan. However, besides the "Big 3," a host of smaller projects also contribute to Kazakhstan's oil development, albeit less prominently. Importantly, we assume only a relatively slow decline in Kazakhstan's older, legacy fields (especially in western Kazakhstan) from the growing application of new technology and improved production practices.
    - **Output from the giant Tengiz field in 2024 averaged 710,000 b/d**. The FGB expansion starts ahead of schedule in early 2025. The TCO project remains the largest Kazakh oil development by production. After jumping by 10% in 2022 (and recovering most of the volume lost amid the COVID-19 downturn), Tengiz production dipped by 1.0% in 2023 to 632,000 b/d. As expected Tengiz returned to a growth trajectory, averaging 712,000 b/d of production in 2024. The FGP, a project with an estimated cost of $47 billion, will add 260,000 b/d to the field's overall production capacity as it ramps up, increasing Tengiz production to more than 870,000 by 2028.
    - **Output from the Kashagan field increased to 434,000 in 2024.** Further, albeit small, growth is expected in 2024–25. In particular, a project recently underway to increase gas supply to a third-party processing plant, with capacity of 1 Bcm/y, is expected to enable an increase in Kashagan oil output to 450,000 b/d. The chief precondition for larger-scale Kashagan production remains the Phase 2 expansion program, Under increasing pressure to finalize a "full-scale" development plan for Kashagan, the consortium recently proposed a modified Phase 2 expansion program. This includes two separate projects, Phase 2A and Phase 2B. Phase 2A aims to increase plateau oil production to 500,000 b/d; the project is expected to be completed in 2026. Phase 2B will raise output to a higher ceiling of about 700,000 b/d; an FID has not yet been taken on this project, but previous announcements indicated that startup would be in 2030..we now assume that the second phase of the expansion is never sanctioned, so production stretches to only about 470,000-480,000 b/d through some additional minor debottlenecking.
    - The **Karachaganak**'s annual gross production of liquids has been basically flat since 2007, ranging between about 257,000-285,000 b/d; Karachaganak's liquids output is mainly condensate, so its operation is exempt from OPEC+ restrictions. Field production loses approximately 18%-19% of its volume in the process of stabilization, now undertaken entirely at the field itself (previously, some took place within Russia). This significantly reduces the liquid volumes available for pipeline shipment or exports
- We assume that a moderate amount of Kazakh crude continues to be delivered into the Baku-Tbilisi-Ceyhan (BTC) pipeline, following the resumption of Kazakh deliveries via BTC in 2022 (for the first time since 2015). This route is being employed as part of a broader export diversification strategy given recent concerns about heavy reliance on the Caspian Pipeline Consortium (CPC) pipeline and uncertainties about Kazakh-origin crude transiting Russia through the JSC Transneft pipeline system to export markets. We also take the view that there is only limited opportunity for Kazakhstan to diversify its crude oil exports by exporting more to China (mainland) overland via the Kazakhstan-China (mainland) pipeline.

Data compiled: May 2025.
For a more detailed outlook see Eurasian Oil Export Outlook
Source: S&P Global Commodity Insights.

Europe to remain the primary market for growing Kazakh crude output

Demand from Asia Pacific is expected to rebound in light of the Houthi truce affecting Red Sea shipping

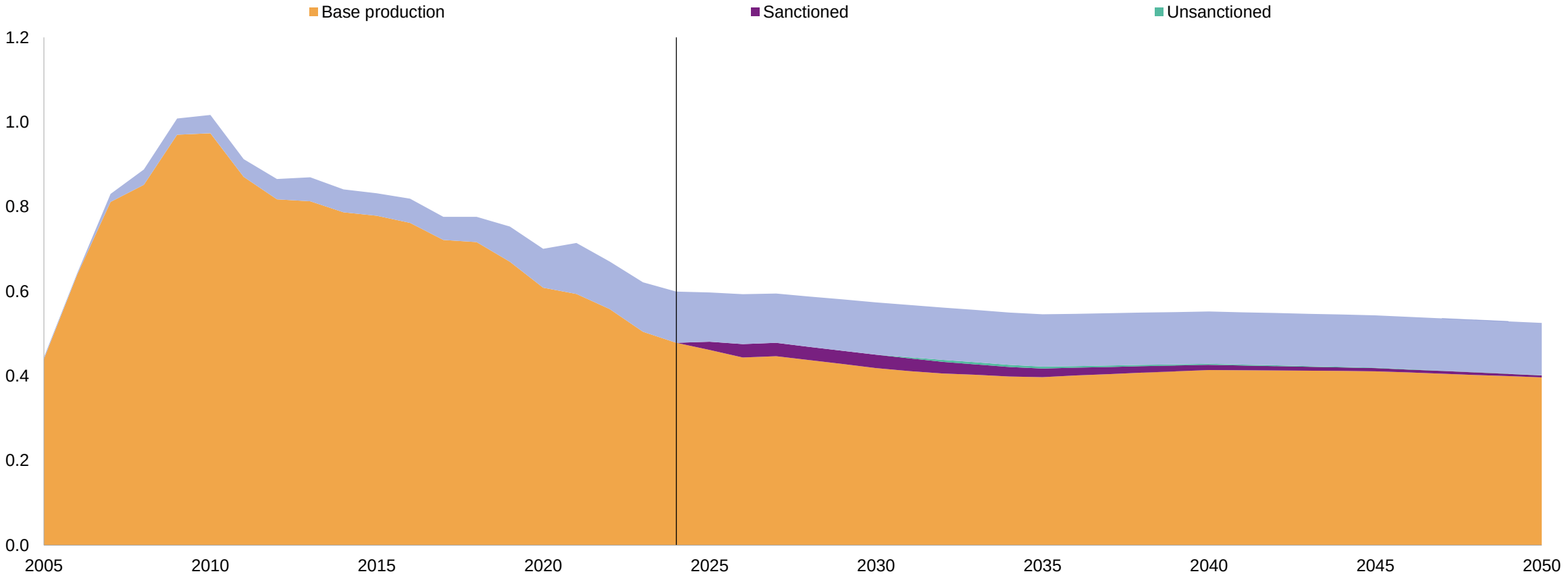
Kazakhstan's seaborne crude oil exports (thousand b/d)



Data compiled May 27, 2025.
Source: S&P Global Commodity Insights: IC-251059-01.

Production from new projects is expected to stabilize Azerbaijan's output as Azeri-Chirag-Guneshli field complex volume shrinks

Azerbaijan's crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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Azerbaijan crude production has already peaked, but condensate will continue to grow through the end of the decade

- Azerbaijan's 2024 crude output dropped to 599,000 b/d. Overall, the pace of the drop in oil output slowed in 2024, declining by 3.5% year on year. Azerbaijan has stayed within its OPEC+ quota over the agreement period without difficulty owing to the natural decline in its main producing field. Output has been on a long-term decline since reaching a peak of just over 1.0 million b/d in 2010.
- The share of the international consortium (Azerbaijan International Operating Co. [AIOC]) operating the Azeri-Chirag-Gunashli (ACG) megaproject dropped to about 59% of total national in 2023. ACG production has been in decline since 2010; therefore, so has national production. ACG already hit maximum production more than a decade ago, in 2010, at 823,000 b/d. Importantly, crude oil output has been under restriction during most of the period starting in 2017 as part of Azerbaijan's pledged commitments to the OPEC+ deal.
- However, condensate production (mostly from the Shah Deniz project) is excluded from Azerbaijan's OPEC+ commitments (since May 2020). In practice, though, the "natural decline" rate of Azerbaijan's main producing fields has tended to exceed officially planned reductions in recent years, and starting in the second half of 2021 Azerbaijan has consistently "underproduced" relative to its monthly OPEC+ targets (in the estimate of Commodity Insights). Condensate production has now been enhanced by the launch of the Absheron offshore gas project in 2023, the first phase of which yields about 11,000 b/d.
- Condensate volumes produced at Shah Deniz are assumed to be determined largely by the field's gas production (and sales). First liquids production began in early 2007. Production is expected to expand to about 125,000 b/d by 2030, where it holds through 2050.
- Declining output from the ACG field complex in the Caspian Sea drives Azerbaijan output lower over the long-term.
- We assume full realization of the Azeri Central East project (the seventh ACG platform), which was launched in 2024. This will add about 300 million barrels to total production from the new platform (a $6 billion investment sanctioned several years ago); this, however, reduces the overall rate of ACG decline rather than adding to maximum production.

Data compiled: May 2025.
For a more detailed outlook see Eurasian Oil Export Outlook
Source: S&P Global Commodity Insights.

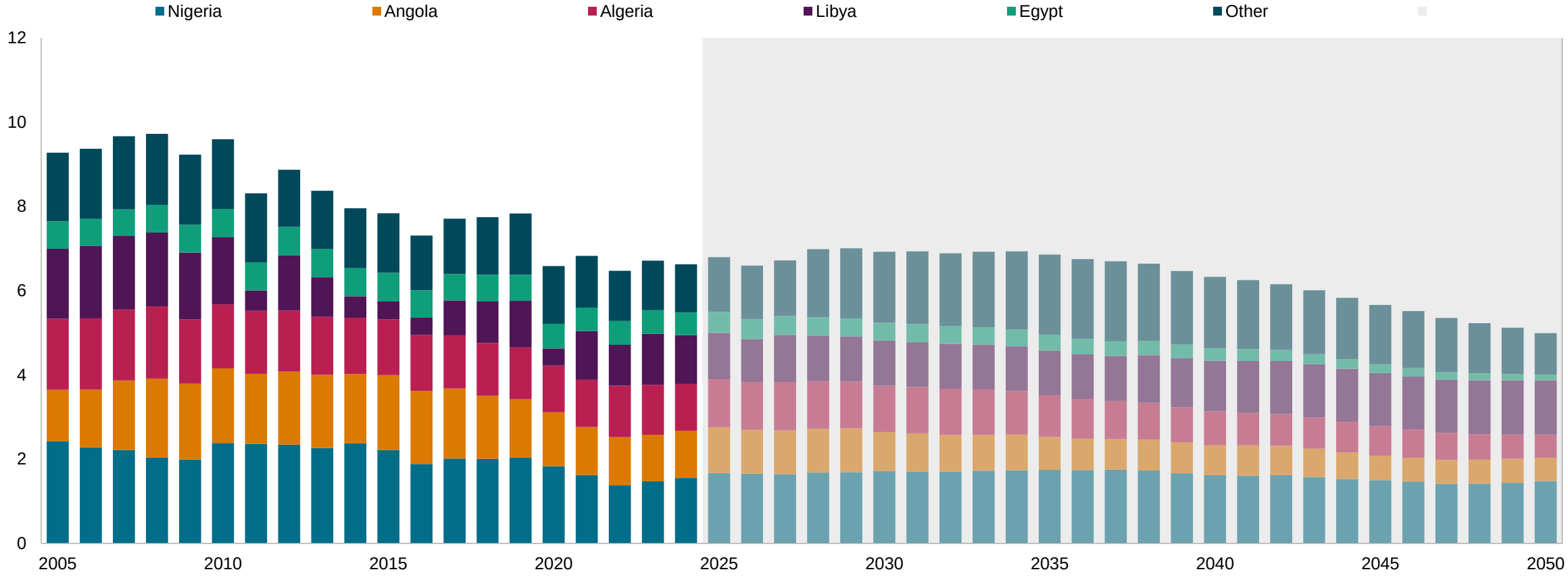
Other CIS countries: Turkmenistan is the only market with growth out to 2050, with base production rising in the next decade and out to the mid 2040s

- Elsewhere in the CIS region, new crude supply additions are extremely limited, with most new hydrocarbon development focused on gas
- Our outlook for production in Turkmenistan, the region's fourth largest producer, is for production to flatten for the next five years, before lifting in the early to mid 2030s.We currently assumes production in Turkmenistan begins to rise in the mid 2030s, and is lifted to a maximum of 237,000 b/d by the mid-2040s
  - We continue, however, to take a generally pessimistic view of future Turkmen oil production prospects. This is due to limited condensate production in the main gas-producing area in eastern Turkmenistan (although this could change if the development of the deeper reservoirs of the giant Galkynysh field is pressed successfully and ends up having significant condensate), difficult and largely depleted reservoirs in onshore western Turkmenistan and an assumption of generally limited oil prospects in most of the Turkmen offshore sector of the Caspian.
- Uzbekistan', which currently produces ~60,000 b/d is relatively small compared to its regional peers, and it has been experiencing a gradual decline. The country focuses more on natural gas production and export, with significant investments in gas infrastructure and development projects. Crude and condensate production is set to enter a significant decline from 2028.
- Other minor producers in the region account for a combined 80,000 b/d, but none have significant growth prospects. This pool of countries – Ukraine, Belarus, Kyrgyzstan, Tajikistan and Georgia – will see production approximately halved by 2050. The largest, Belarus, which produces in the onshore fields in the Pripyat Trough in the southeast's Gomel region, for example, is mature and well past peak production.

Data compiled: May 2025.
For a more detailed outlook see Eurasian Oil Export Outlook
Source: S&P Global Commodity Insights.

African crude and condensate production by major countries

Major African oil producers (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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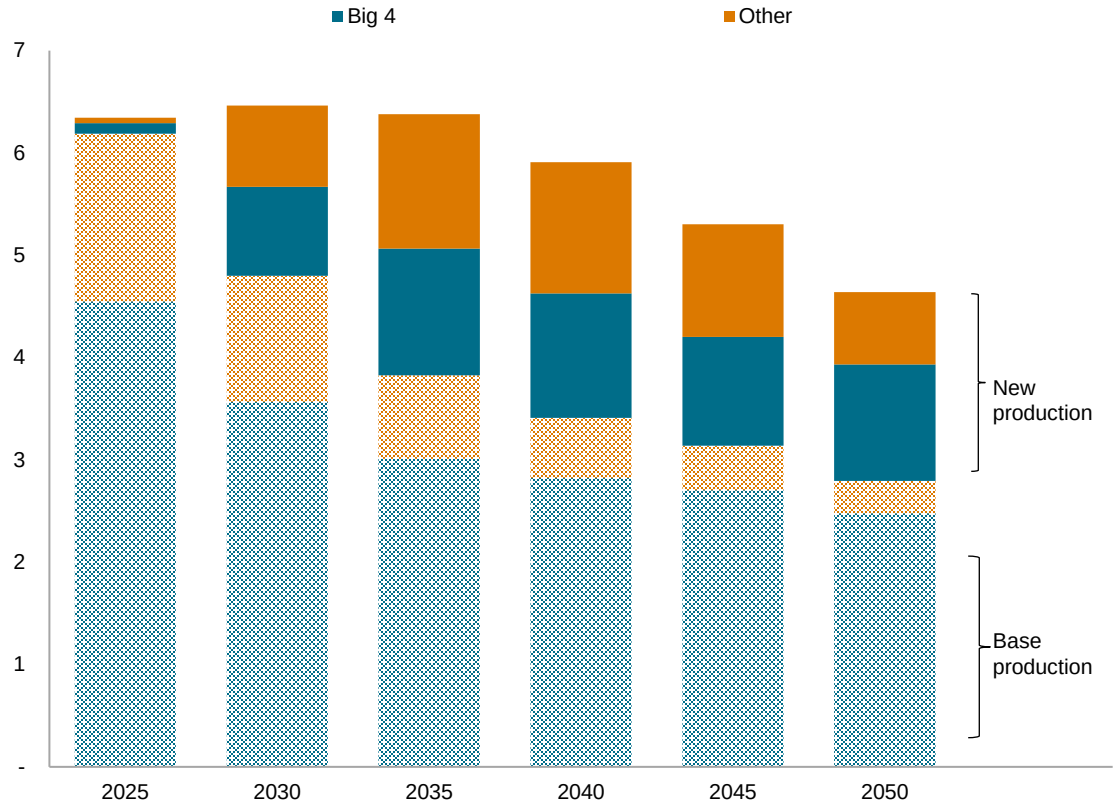
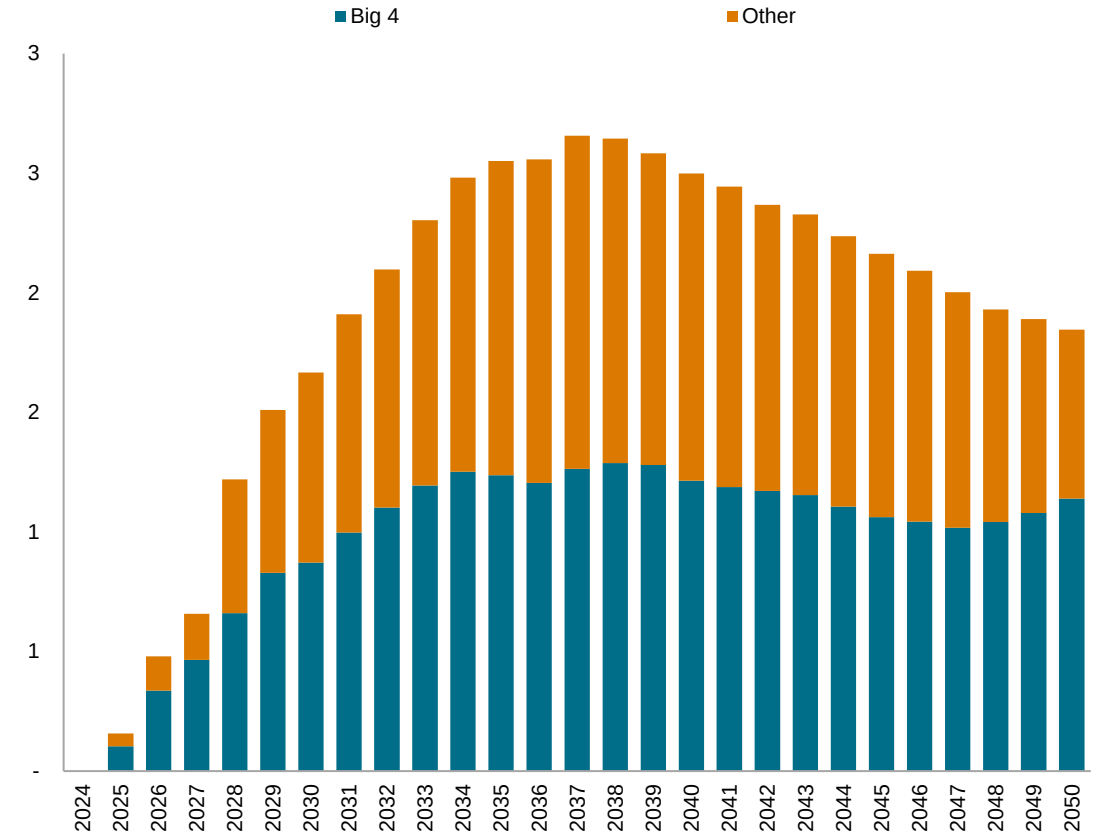
By 2040, close to half of the new crude additions to Africa's total production will come from producers outside of the region’s Big 4, before their share starts to fall

Africa's crude production outlook (million b/d)



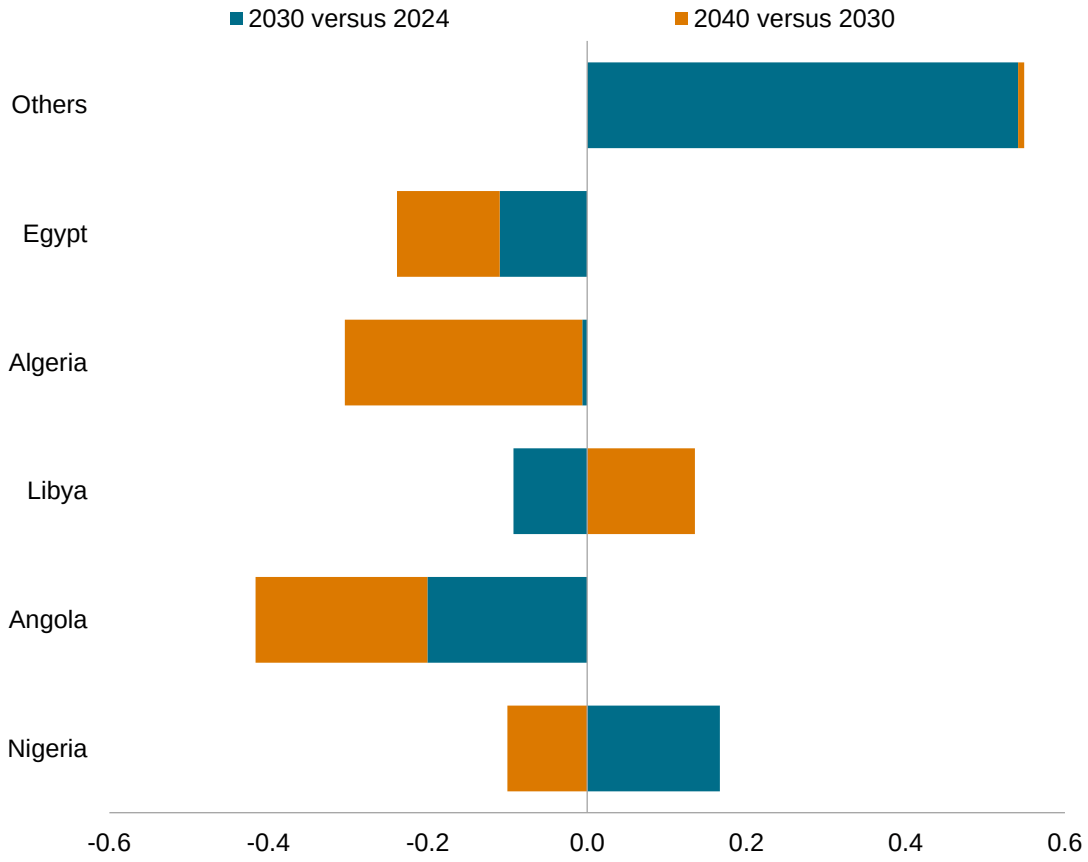
Africa's crude production outlook (million b/d)



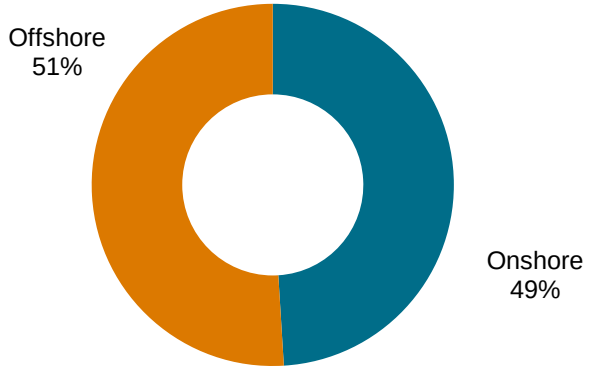
Data compiled: May 2025.
Big 4 countries include: Algeria, Angola, Libya and Nigeria
Source: S&P Global Commodity Insights

Africa’s output is expected to plateau in the next few years, bolstered by increased production from smaller producing nations

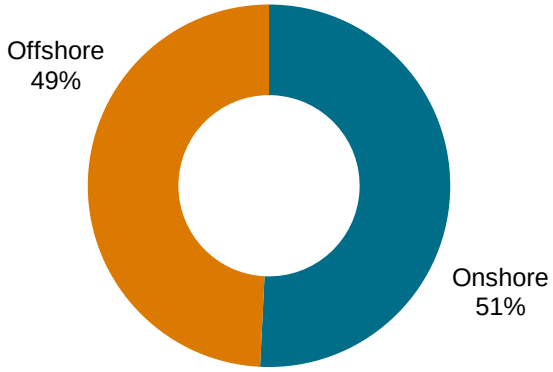
Africa's crude oil production changes (million b/d)



African terrain in 2024



African terrain in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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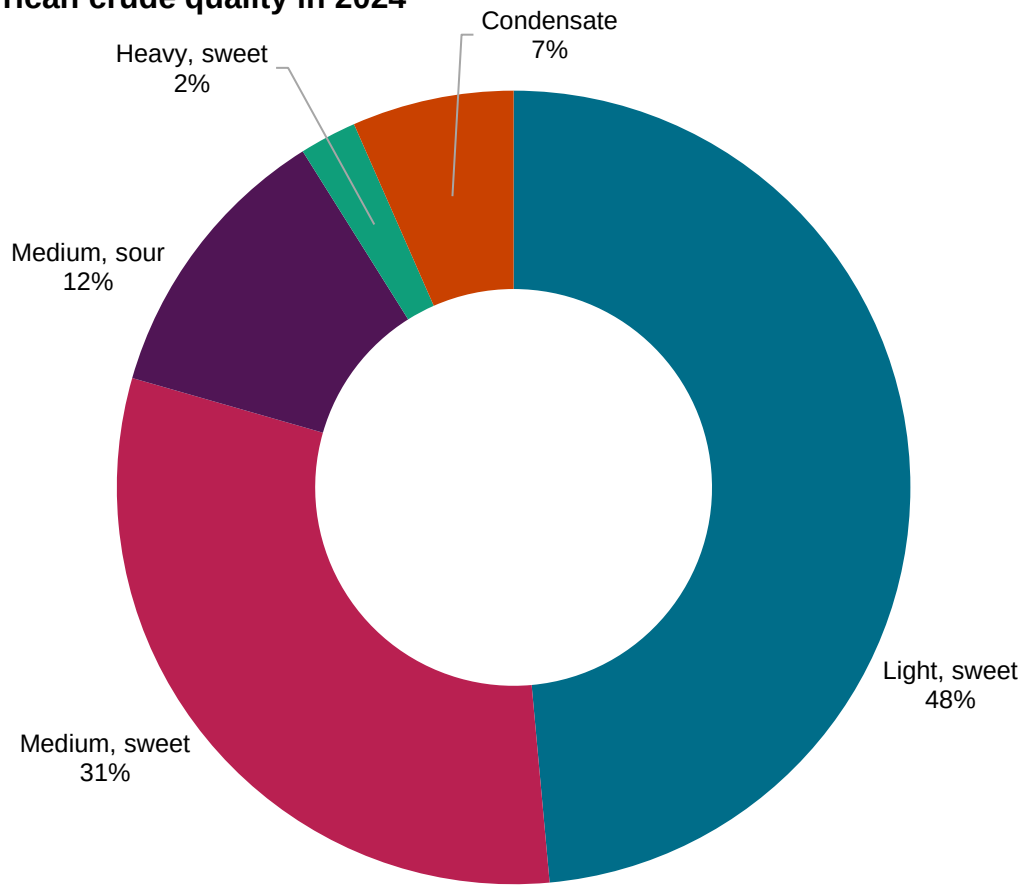
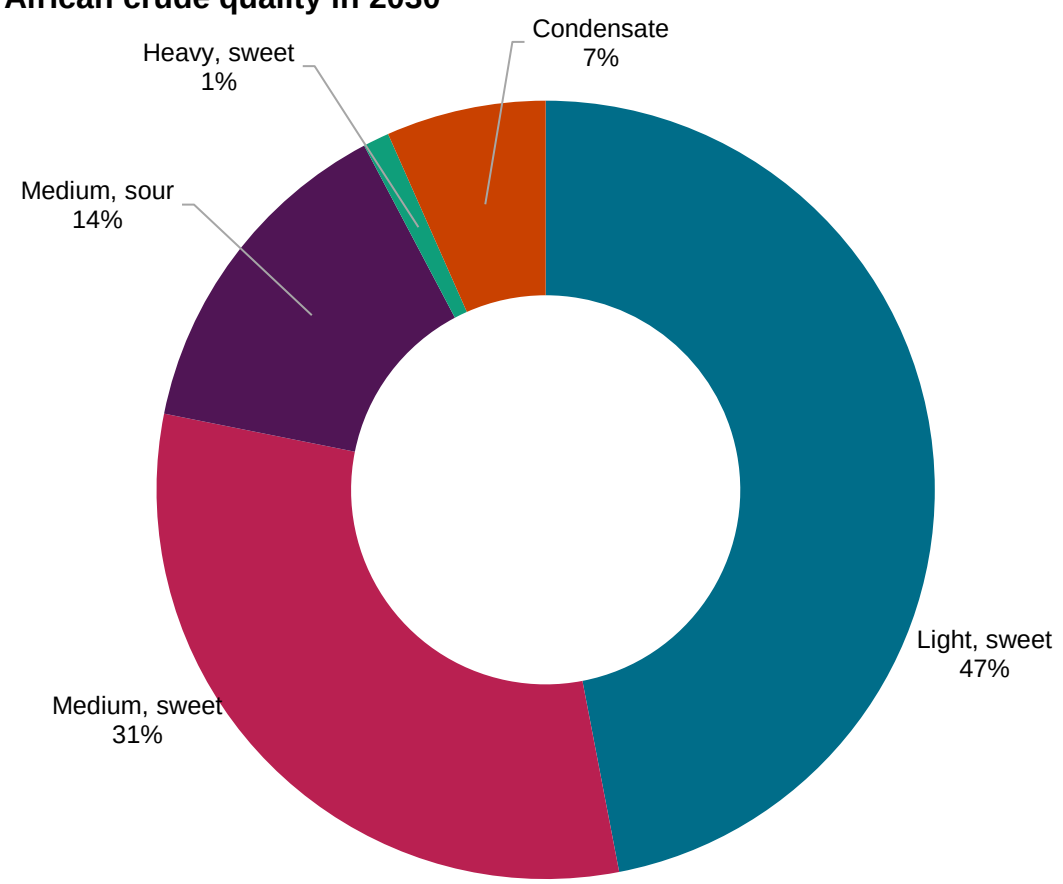
Commodity Insights

Africa’s crude quality is expected to remain similar in 2030, before becoming lighter and sweeter by 2040

African crude quality in 2024



African crude quality in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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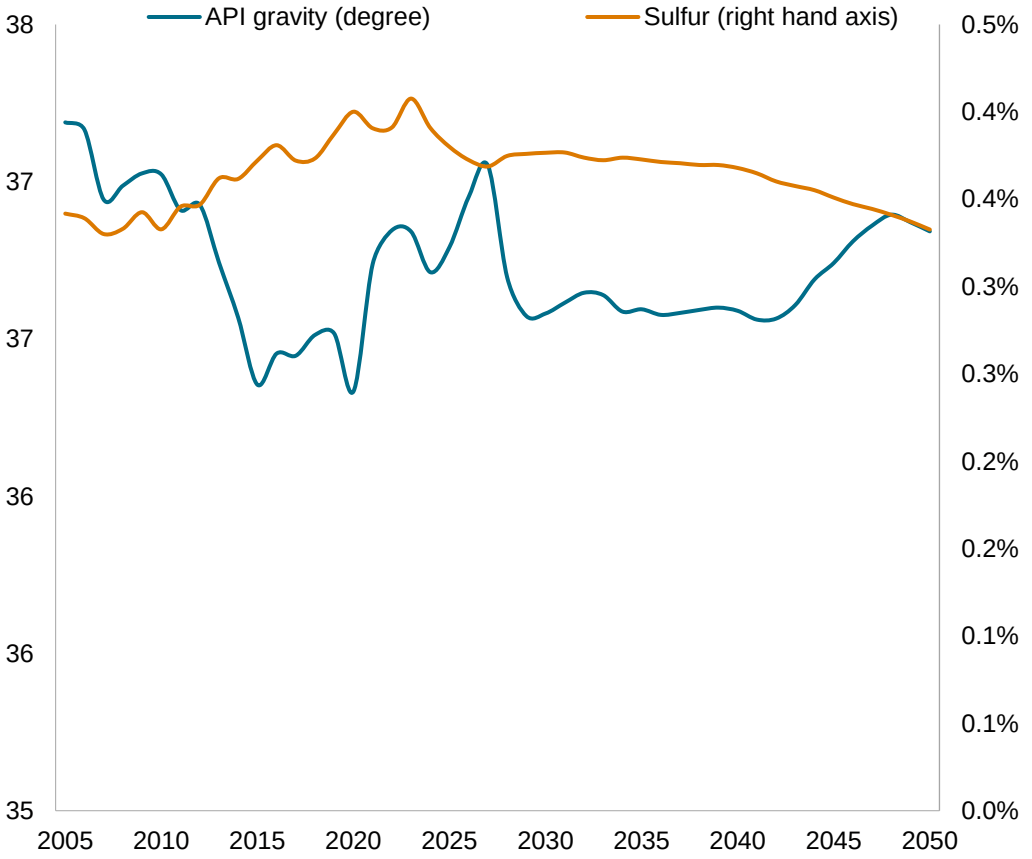
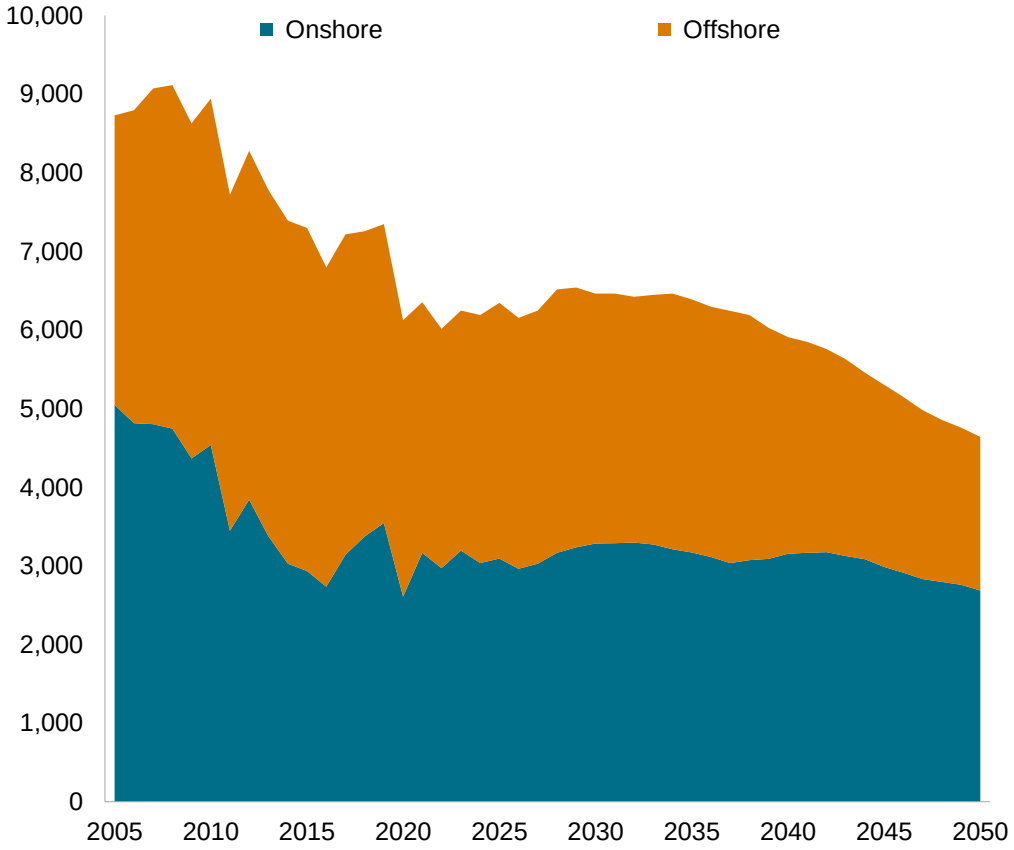
Larger share of onshore production leads to lighter and sweeter African crude slate in the long-term

Africa quality trends



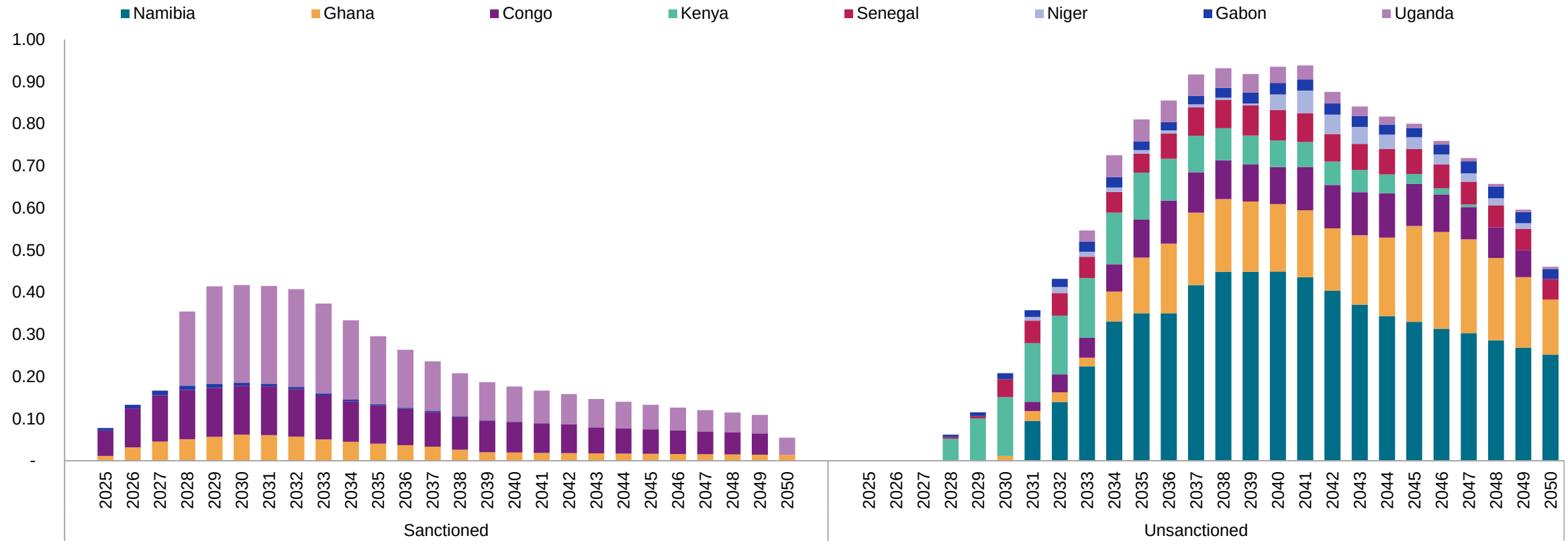
Africa production by depth (thousand b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

The potential for Africa's production growth is significant, but development relies heavily on securing the necessary investments

New source of crude production for selected countries (thousand b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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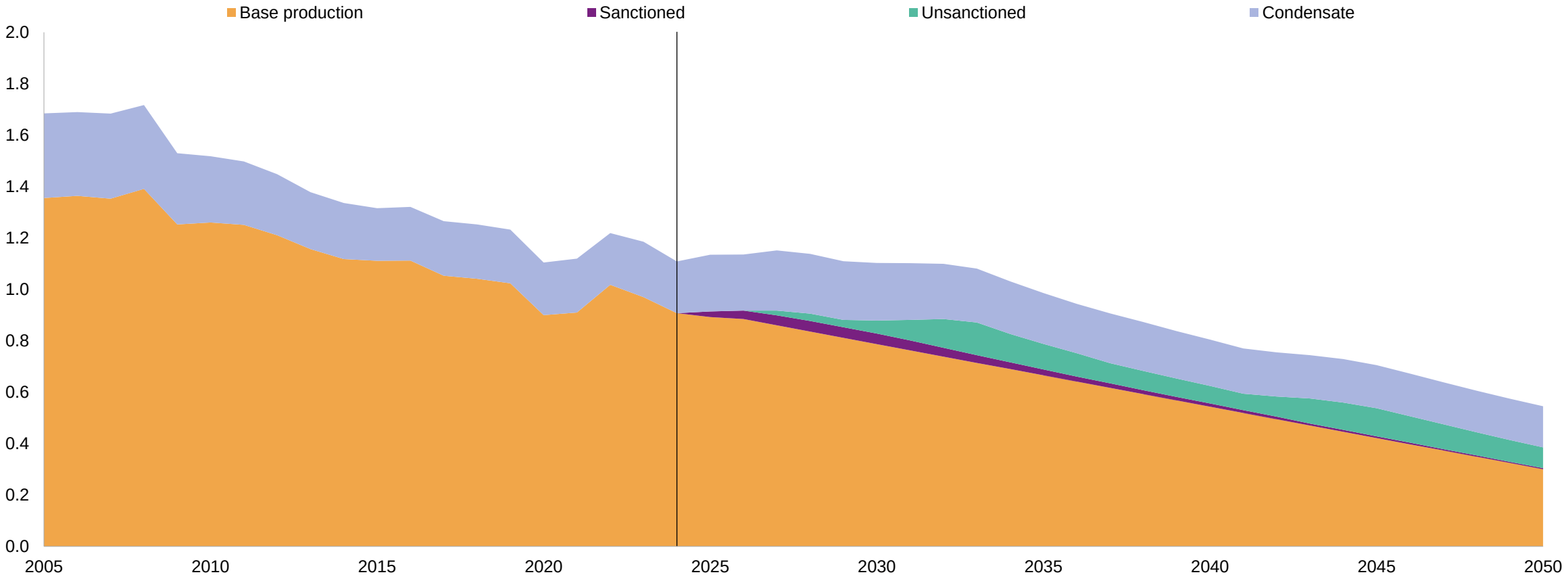
Algeria key messages

- **Algeria’s output averaged 1.11 million b/d in 2024, decreasing by 76,000 b/d year on year.** Crude and condensate production is expected to plateau at around 1.15 million b/d in 2027 following the start-up of several smaller projects including, Bir Seba (Phase 2) and Hassi Bir Rekaiz (Phase 2) in 2025 and 2027, respectively. However, their incremental output will be insufficient to offset Algeria’s base decline during this period.
  - Looking ahead to 2030, Algeria's oil production capacity is expected to hover around 1 million b/d, with no major new projects anticipated to significantly boost output. The focus remains on maintaining current production levels through redevelopment and infill drilling.
  - Algeria's crude oil production in 2024 was constrained by OPEC quotas, maintaining a level around 907,000 b/d. This represents a decrease from the 970,000 b/d recorded in 2023. Base crude production is expected to continue to decline in the mid-term, falling to 787,000 b/d by 2030.
- **Hassi Messaoud, which started production in 1958, remains Algeria’s largest producing field.** In 2016, production reached its highest output level of 438,000 b/d since the early 1980s but has declined since, producing 311,000 b/d in 2024.
- **Algeria's upstream sector is dominated by Sonatrach**, which operates around 70% of all acreage and holds a significant share of production. The country launched its first bid round in a decade in October 2024, aiming to attract IOCs to invest in new exploration and development projects. Despite the new hydrocarbon law introduced in 2019, which offers better terms for E&P companies, the anticipated rush for new acreage has not materialized. However, partnerships with Sonatrach, such as those with Eni and Occidental, continue to bring smaller projects into production.
- **Exploration activity in Algeria has been primarily near-field**, with Sonatrach and Eni leading efforts in the Hassi Messaoud and Berkine basins. The new hydrocarbon law is expected to gradually boost exploration activity. In 2024, 14 hydrocarbon discoveries were reported, although they are understood to be modest in size. The government is keen to boost both oil and gas production to support economic performance, with a particular focus on reducing gas flaring and increasing gas exports to Europe. Major infrastructure projects, such as the Trans Sahara Gas Pipeline and the GALSI pipeline, are in various stages of development, aiming to enhance Algeria's export capacity.

Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Algerian output expected to resume long-term decline amid lack of major new investments and aging fields

Algeria's crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

S&P Global
Commodity Insights

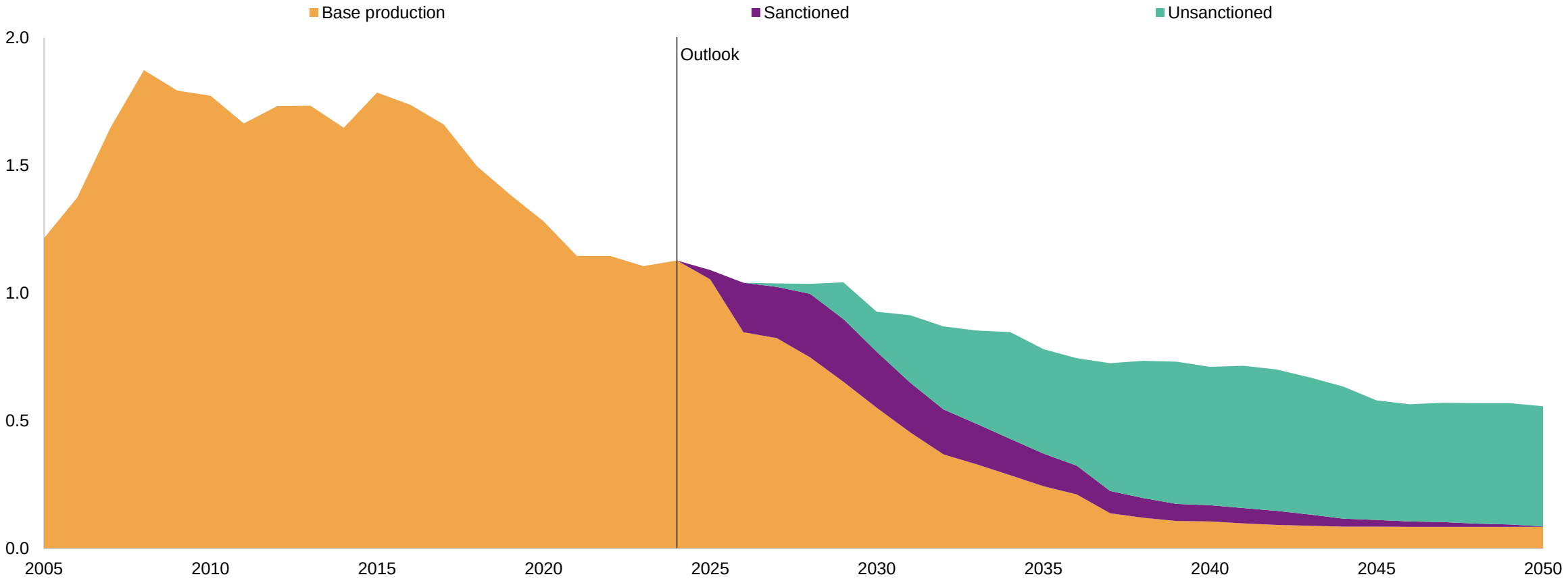
Angola key messages

- **Angola's crude oil production in 2024 averaged around 1.13 million b/d**, maintaining a stable output compared to previous years. Despite efforts to sustain production levels, the country's output has been in decline since 2008, primarily due to the maturity of its major offshore fields. Looking ahead, Angola aims to keep production at or above 1.04 million b/d until 2029, with new projects like the Agogo Phase 3 and Kaminho Condensate Development expected to partially reverse the decline by 2026 and 2028, respectively. However, without significant new discoveries, production is anticipated to fall below current levels by the 2030s.
  - Several projects are anticipated to come online in the coming years, including the Agogo Phase 3, which involves a 120,000 b/d FPSO, and the Ndungu development, both expected to begin in 2026. These projects, along with others like the Block 17/06 Begonia project, are crucial for offsetting the natural decline of Angola's mature fields. The government has been proactive in offering improved fiscal terms to attract exploration and development, particularly in frontier areas like the Namibe Basin.
  - Kizomba B, was the largest producing field in Algeria in 2024, with an output of 75,000 b/d, a 40,000 b/d increase from 2023. Moreover, the Dalia Complex, operated by TotalEnergies, remains one of Angola's largest producing fields, with a crude output of 64,000 b/d in 2024. The field, which has been in production for over a decade, is part of Angola's mature asset base, contributing significantly to the country's overall production. However, like many of Angola's fields, it faces challenges due to its maturity, having produced a substantial portion of its recoverable volumes.
- Angola's upstream exploration and investment landscape is marked by efforts to attract foreign capital through improved fiscal and contractual terms. The government has initiated a multi-year bid round program, with the 2023 onshore bid round and the upcoming 2025 offshore deepwater Kwanza Basin round being key components. Despite these efforts, exploration activity has been limited, with only a few exploratory wells drilled annually since 2015.
  - Companies like Azule Energy and TotalEnergies are leading exploration efforts, focusing on infrastructure-led campaigns to maximize existing assets. The government continues to encourage investment in mature fields through new legal and tax regimes aimed at extending their economic life.
- Angola has a well-developed offshore setup, with 17 FPSOs in operation. The country is also expanding its refining capacity, with new refineries like the Cabinda and Soyo refineries set to increase processing capacity significantly. These developments are part of Angola's broader strategy to enhance its oil and gas sector's efficiency and sustainability, with initiatives like the Angola LNG plant playing a crucial role in reducing flared gas and emissions.
- Angola left OPEC on January 1, 2024, amid disagreements over production baselines and quotas. The decision was announced in late 2023.

Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Sanctioned project volumes will struggle to offset steep Angolan base decline in the near term

Angola's crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

S&P Global
Commodity Insights

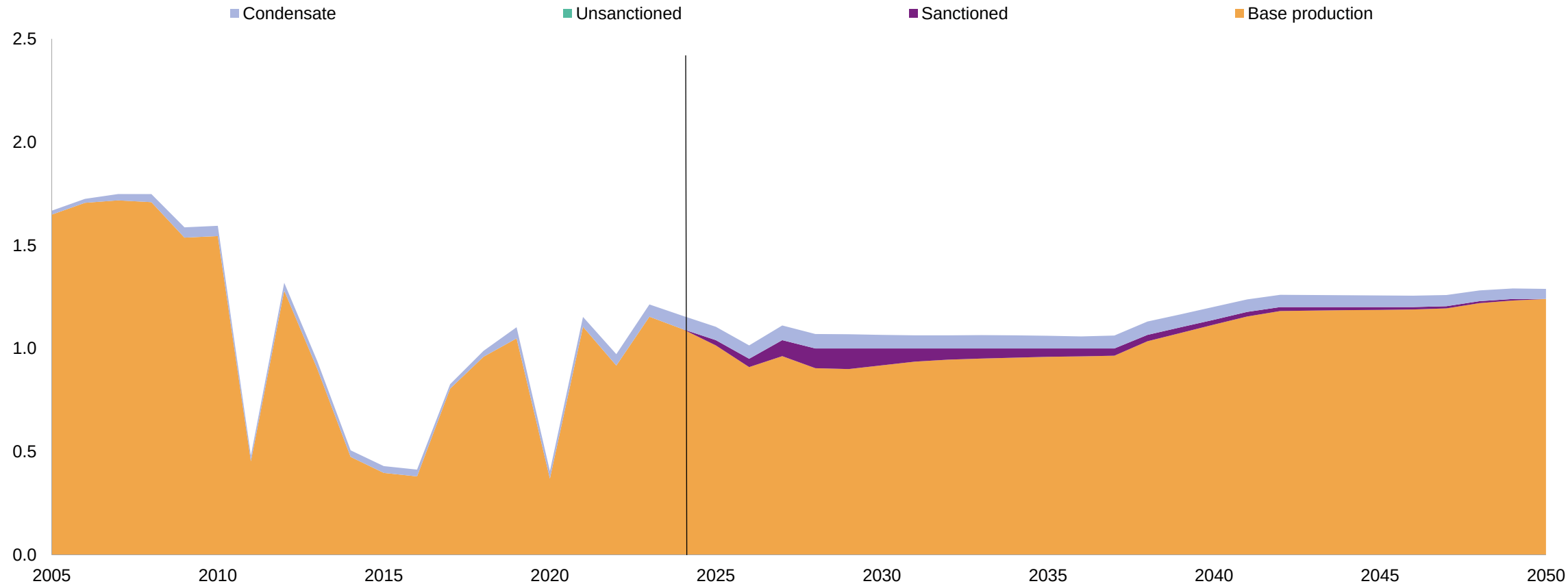
Libya key messages

- **Libya's crude oil production in 2024 averaged over 1.1 million b/d, down from 1.2 million b/d in 2023. Production peaked at 1.3 million b/d in late 2024 after a temporary drop in August caused by politically motivated closures.**
  - In August 2024, disruption due to a blockade by protesters affecting Libya's 300,000 b/d El Sharara oilfield resulted in NOC declaring a force majeure. As a result, Libya's eastern government vowed to declare a nationwide force majeure to halt all oil production and exports in reaction to the ousting of Central Bank Governor Siddiq al-Kabir by Libya's western government.
  - Looking ahead, Libya aims to reach 2 million b/d by 2028, although achieving this target will require significant infrastructure investment and resolution of political challenges. We except Libyan production to plateau close to 2024 levels through mid to late 2030s.
  - The Mabruk NC017 redevelopment project and NC041 project have both reached FID and are expected to come online in 2025 and 2027, respectively.
  - Efforts to further boost capacity are ongoing, although the infrastructure is generally poor after years of conflict and underinvestment. Meanwhile, there remains considerable potential for future supply disruptions from armed groups and local communities keen to use control of oil flows as leverage to press their claims. New investors are unlikely to emerge while the civil conflict continues. However, any progress towards a unity government could lead to a significant uptick in interest given Libya’s significant proven undeveloped reserves, pipeline and processing infrastructure, and untapped exploration potential.
- **We expect production to drop below 1.1 b/d in the second half of this decade** and not return above 1.1 million b/d until the late 2030s unless the recent peace agreement is consolidated and the political situation has stabilized, enabling material investment in infrastructure, both upstream and midstream.
  - The NOC plans to initiate a licensing round in mid-2025, although this may be hindered by ongoing political issues. Eni and BP are expected to lead exploration efforts, particularly in offshore deep-water reservoirs. The Sirte Basin remains a key area for exploration, with significant potential for new discoveries despite its maturity.
  - Rebuilding infrastructure and developing nearby areas provide the quickest opportunity for boosting output. Most of the long-term potential for increased production lies in new, yet-to-be-approved projects. Nevertheless, if political discord continues and economic disparities remain, there is a considerable risk of disruptions and future shutdowns due to strategic manoeuvres by competing militias or community initiatives. This situation introduces substantial uncertainty regarding the sustainability of current production levels and prospects.

Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Libyan output is expected to plateau close to 1.1 million b/d over the next decade failing to recover amid poor state of infrastructure after years of conflict

Libya's crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

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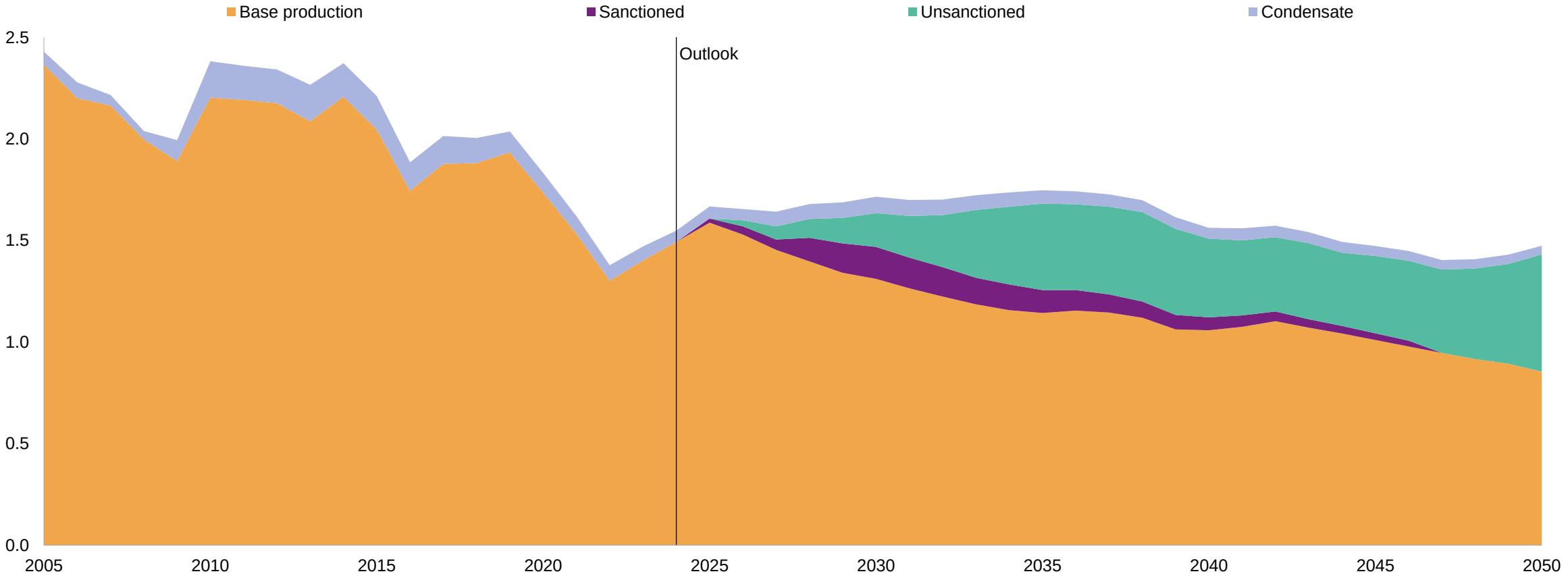
Increased domestic refining capacity and supply requirements are likely to affect export volumes

- **Nigeria produced approximately 1.55 million b/d of crude and condensate in 2024,** surpassing the previous year's output despite ongoing challenges such as oil theft and vandalism. The country met its OPEC+ crude production quota of 1.50 million b/d,.
- Rising production is a positive step following 2022 lows, as output was severely impacted by oil theft and infrastructure problems, pushing production to a low of 1.1 million b/d in September and October of 2022. As of early 2025, Nigeria's upstream sector is at a critical juncture, characterized by significant changes in competitive landscape and production dynamics. The onshore Niger Delta is now predominantly controlled by indigenous operators, reflecting a shift towards local participation. Additionally, the recent sanction of a major offshore project is expected to bolster production and investment in the coming years.
- Looking ahead, Nigeria's oil production is expected to increase in 2025 and then plateau through the late 2020s. Production is then expected to then surpass 1.7 million b/d, driven by large deepwater projects including Shell's Bonga North, which is anticipated to come online before 2030.
- The medium to long-term outlook suggests a potential decline unless new projects are sanctioned soon. Other notable projects, which are yet to be sanctioned but expected to contribute to future production are the Preowei development, Usan phase 2 and Owowo.
- Exploration and investment activities in Nigeria's upstream sector were subdued in 2024, with only a few significant developments reported. Chevron appraised the Meji field, while First E&P began exploring the shallow water OML 85 block.
- The Nigerian Upstream Petroleum Regulatory Commission (NUPRC) concluded its 2024 Licensing Round, attributing 25 blocks primarily to Nigerian independents, indicating successful measures to stimulate investment. Major players like Shell, TotalEnergies, and ExxonMobil finalized divestment deals, reshaping the competitive landscape. Looking ahead, global IOCs like Eni and TotalEnergies are preparing to resume offshore exploration in 2025, potentially reviving exploration activities.
- Nigeria is actively working to improve its midstream and downstream infrastructure to enhance natural gas distribution and crude oil refining capacity, aiming to reduce fuel import dependence.
- The country’s refining capacity is ramping up, mainly through a new private refinery developed by Dangote Industries, with capacity of over 600,000 b/d, which was formally launched in May 2023. While the facility commenced operations in early 2024, it is expected to ramp up production to full capacity through 2025 and 2026, with a partial reliance on imported fuel likely to continue over the next few years.
- Production at the newly on-stream refineries will increase the government’s focus on enforcing domestic supply obligations. The initial supply requirement for the Dangote refinery alone is set by NUPRC at 325,000 b/d for the first half of 2024.
- The existing state-owned refineries have a cumulative nameplate capacity of 445,000 b/d but have long struggled to operate above a 15% utilization rate. Operations at all state-owned refineries have been completely suspended since January 2020 for comprehensive repairs, and the state awarded contracts in 2021 for their rehabilitation. The Warri and the Port Harcourt refineries were formally relaunched at end-2024. However, as of late May 2025, neither refinery is on stream, with the Port Harcourt 60,000 b/d unit closed again for maintenance.

Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Nigeria’s output is expected to plateau at close to 1.6 million b/d, but supply disruptions pose a risk to output and future investments in the sector

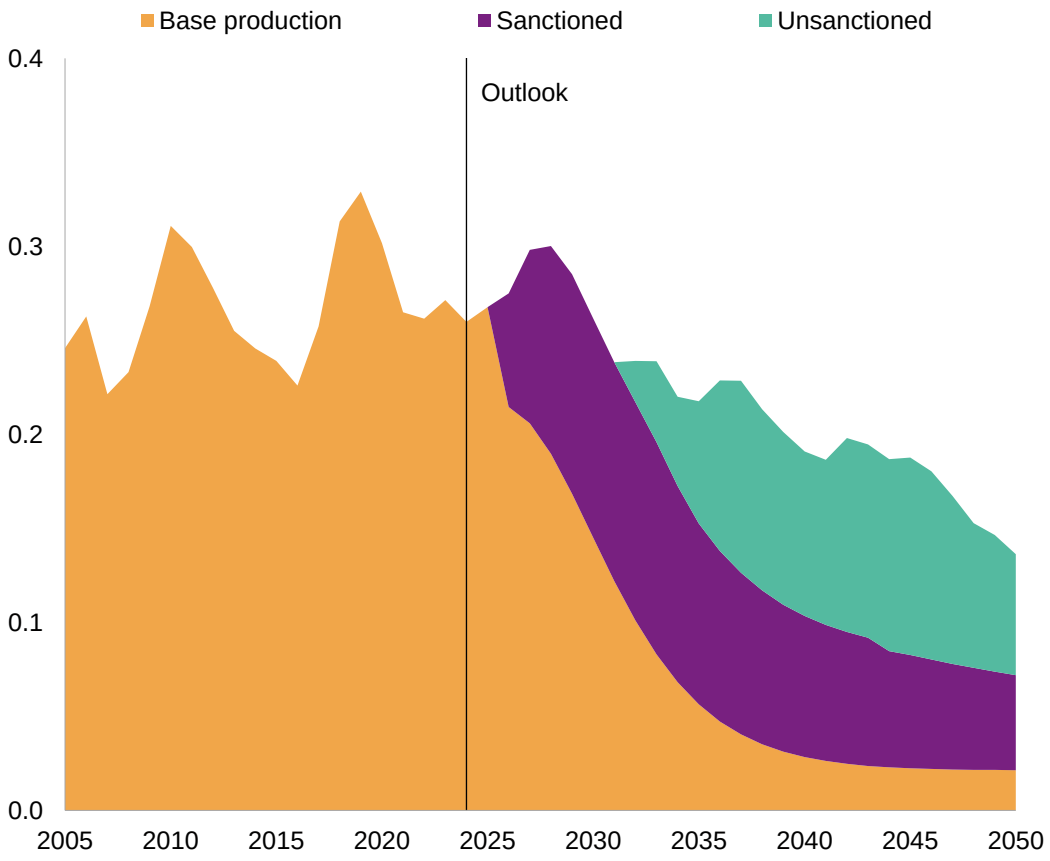
Nigeria's crude and condensate production by development (million b/d)



Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Congo’s output is expected to rise to 300,000 b/d by 2028, before declining in the 2030s. In the long term, the possibility of unsanctioned projects may revive output

Congo's crude and condensate production by development (million b/d)

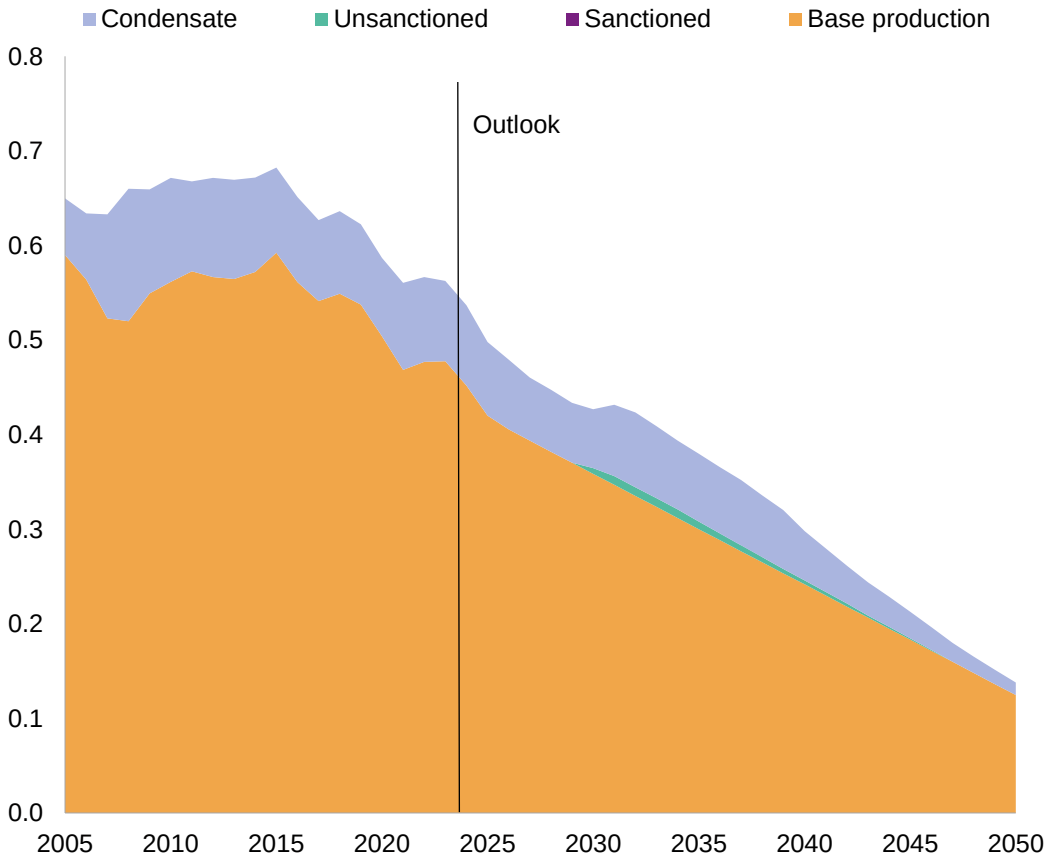


Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

- In 2024, the Republic of Congo's crude oil production averaged approximately 260,000 b/d. The government announced plans to increase production to 500,000 b/d within three years, focusing on redeveloping existing fields and drilling new infill wells. This ambitious target is supported by major international oil companies such as Perenco, Eni and TotalEnergies.
- Looking ahead, We expect production outlook to remain stable amid efforts to counter declines through development drilling and new projects. By 2030, production is expected to be bolstered by ongoing investments and exploration activities.
- The Moho Nord field, operated by TotalEnergies, was the largest producing field in the Republic of Congo in 2024, contributing significantly to the country's total output. In 2024, Moho Nord produced 56,700 b/d, accounting for approximately 22% of the nation's total production. Production at Moho Nord is forecasted to decline in the coming years, with closure expected by 2029.
- Exploration and investment activities in the Republic of Congo have seen fluctuations, with a notable rebound in offshore drilling in 2022. However, exploration activity declined again in 2023. Companies like Eni and TotalEnergies have been active in drilling high-impact wells, although some efforts, such as TotalEnergies' Niamou-1 well, did not encounter hydrocarbons. The government plans to launch an international licensing round in 2025, offering opportunities across various blocks, including marginal and deepwater assets.

Egyptian oil production is experiencing a persistent downward trend, with few opportunities for initiating new projects

Egypt's crude and condensate production by development (million b/d)

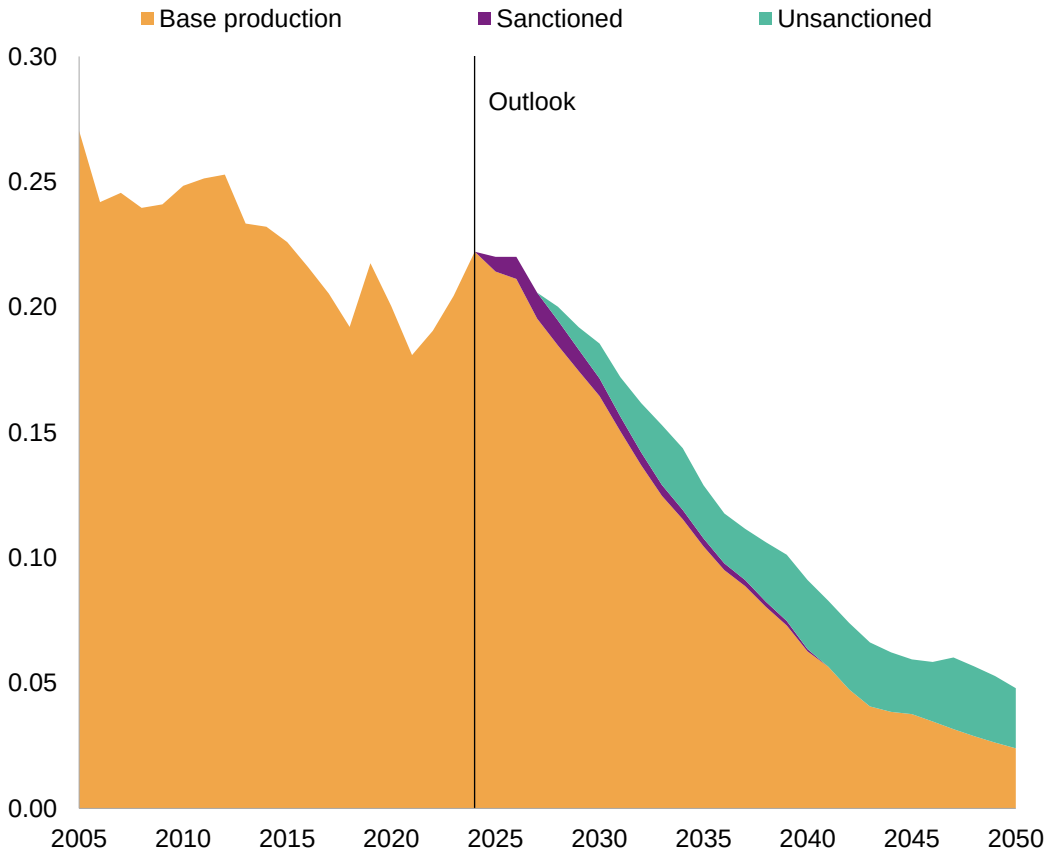


- Egyptian crude and condensate output averaged 537,000 b/d in 2024, down from 563,000b/d in 2023. Despite efforts to increase output, Egypt's production remains below its 2015 peak of 682,000 b/d. Looking ahead, Egypt's crude production is expected to continue its decline, falling to 427,000 b/d by 2030 and 138,000 b/d in 2050.
- The country faces challenges in maintaining production levels due to declining fields and limited new exploration successes. Projects such as Dragon Oil's North Safa field, which started production in early 2024, are expected to contribute to short-term gains, but these are unlikely to offset the overall downward trend.
- Egypt's upstream sector is dominated by IOCs such as Eni, BP, Shell, and Apache, with state-run agencies as mandatory partners for development concessions. Despite the presence of these major players, capital expenditure in the sector is at its lowest levels observed over the past decade. Chevron and Eni are working on the development of the Nargis discovery, expected to come on stream in late 2025.
- Exploration activities continue in the Western Desert, with recent successes including discoveries by IPR Energy and Khalda Petroleum. However, the absence of major new discoveries coming online poses a challenge to Egypt's long-term production outlook.

Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Gabon crude output expected to decline on lower base production from aging fields

Gabon's crude and condensate production by development (million b/d)

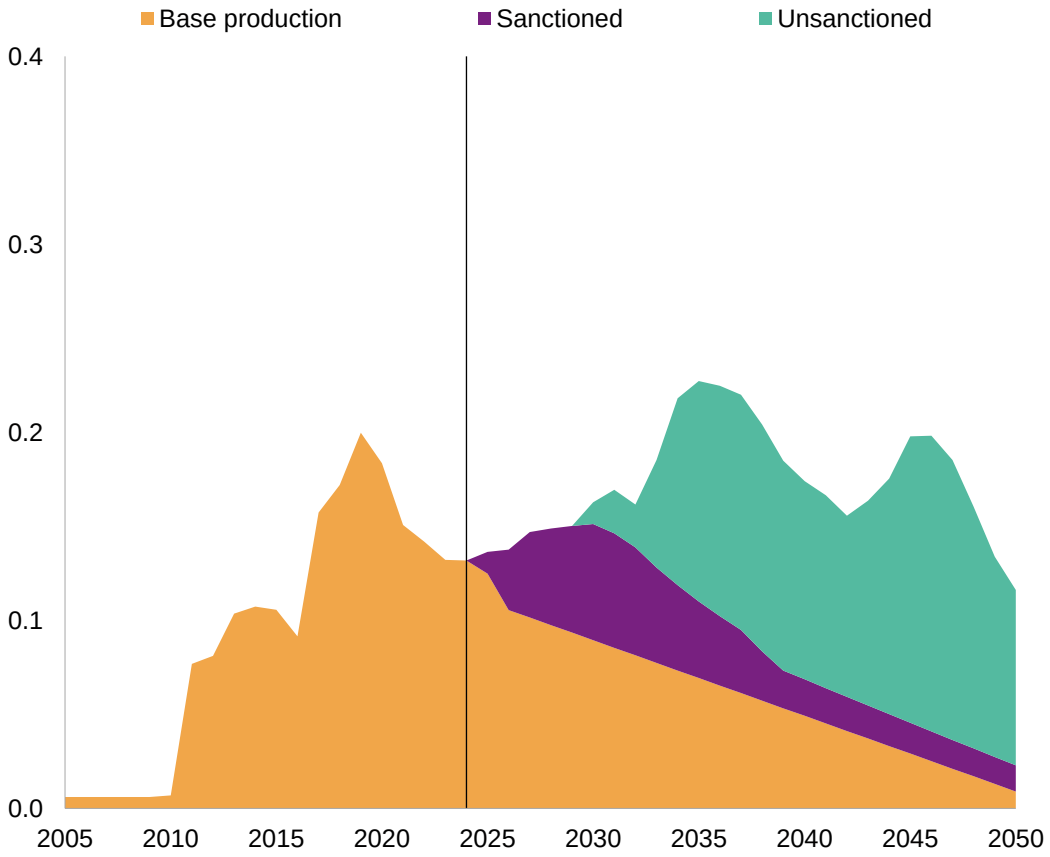


- Gabon, Africa's seventh-largest oil producer, recorded an average crude output of 222,000 b/d in 2024, primarily from mature fields. This marks a continuation of the upward trend in production observed since 2018, driven by investments in mature fields and the development of near-field discoveries in the Gabon Coastal and Lower Congo Basins.
- However, with several large assets reaching maturity, a decline in production is anticipated unless new investments are made. The state-owned Gabon Oil Company's acquisition of Assala Energy in June 2024 has positioned it as a significant player, producing nearly 50,000 b/d.
- Looking ahead, Gabon's oil production is expected to stabilize around 220,000 b/d until 2026, with declines thereafter.
- Gabon's oil sector has seen a gradual recovery from the setbacks of the 2014 oil crisis and the COVID-19 pandemic. The introduction of a more attractive petroleum code in 2019 has led to some progress, with six onshore exploration blocks awarded to Assala Energy and Perenco.
- However, exploration efforts have been hampered by political transitions and a maritime border dispute with Equatorial Guinea. Perenco remains a dominant player, actively investing in both oil and gas projects, including the refurbishment of the Cap Lopez oil terminal and the development of an LNG and LPG terminal. The state-owned Gabon Oil Company is expected to continue Assala's development plans, including a 20-well campaign in the Rabi-Kounga field.

Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Ghana’s production expected to rise through late-2020s, owing to the expansion of several projects

Ghana's crude and condensate production by development (million b/d)



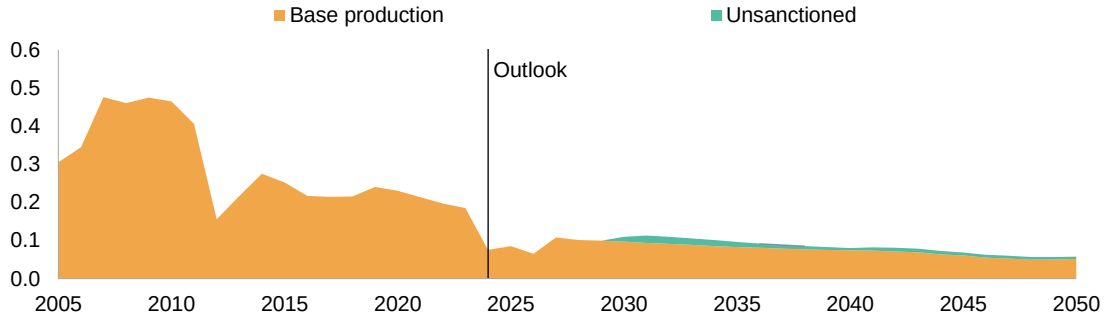
Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

- In 2024, Ghana's crude oil production averaged 131,800 b/d, marking a slight decrease from the previous year. Tullow Oil was responsible for nearly three-quarters of the country's total oil output, primarily from the Jubilee and TEN fields, while Eni contributed the remaining quarter from the Offshore Cape Three Points (OCTP) project. Despite the decrease, new production and water injection wells successfully increased Jubilee's output throughout the year.
- The Jubilee field, operated by Tullow Oil, was Ghana's largest producing field in 2024, with an average output of 95,000 b/d. The field benefited from high FPSO uptime and restored water injection to enhance voidage replacement. The TEN field, also operated by Tullow, averaged approximately 17,450 b/d in 2024.
- Ghana's oil production is projected to level off from 2025 through the mid-2030s. However, uncertainty persists as many deepwater and ultra-deepwater discoveries have not yet been approved for development. We anticipate that these projects, such as Greater Pecan, Wawa 1, and Afina 1, will eventually be developed by the mid-2030s, leading to a second wave of growth.
- Ghana's upstream exploration and investment activities have been focused on enhancing existing assets and preparing for new developments. Tullow Oil continued its investment in the Jubilee and TEN fields, with plans to drill additional wells in 2025 and 2026. Pecan Energies is preparing for an FID for its DWT/CTP block development, with drilling expected to span three years.

Conflict and damaged infrastructure were key drivers behind the oil production collapse in Sudan and South Sudan in 2024

- In 2024, Sudan and South Sudan produced an average of about 75,000 b/d, considerably lower than in 2023, where production averaged 185,000 b/d.
  - In early 2024, South Sudan's oil pipeline was shut down after Sudan's Rapid Support Forces (RSF) hijacked support trucks carrying essential chemicals needed to treat the oil. Without this treatment, the oil thickened and eventually froze inside the pipeline, resulting in the necessity for repairs on the damaged pipeline sections. During the shutdown, only a small portion of oil – around 35,000 b/d – continued to flow.
  - In early 2025, South Sudan's oil production resumed. It is expected that Sudan and South Sudan will average 85,000 b/d of production in 2025. However, this outlook may change following additional damage to South Sudan's oil infrastructure.
  - In May 2025, it was announced that South Sudan's oil production may be halted again following an attack on the Oil Terminal Depot in Port Sudan. The latest shutdown underscores the dangers linked to the political and security situation in the area.
- The future of the upstream sector depends on South Sudan's ability to increase output from existing fields, as production is expected to decline without new discoveries. Political and economic stability is crucial to attract investment for South Sudan and Sudan. Efforts to improve fiscal terms in Sudan risk being changed or retracted after leadership changes.
- On June 2, 2024, during the 37th OPEC and non-OPEC Ministerial Meeting, an agreement was reached on the 2025 required production levels set at 64,000 b/d for Sudan and 124,000 b/d for South Sudan. Sudan is anticipated to remain below OPEC's estimations due to the ongoing conflict and strategic targeting of South Sudan's oil infrastructure.
- In the mid-term, Sudan and South Sudan production is expected to rebound slightly, reaching 110,000 b/d by 2030, primarily driven by the ramp-up of the Arzaq and Hilba project, set to come online in 2030. However, as of 2025, this project remains unsanctioned. For it to be successful, both a de-escalation of the ongoing conflict and political stability would be necessary.

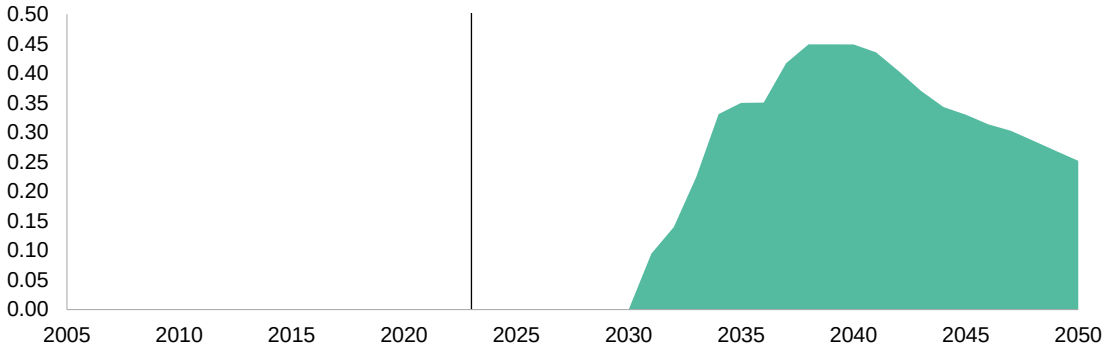
Sudan and South Sudan's crude and condensate production by development (million b/d)



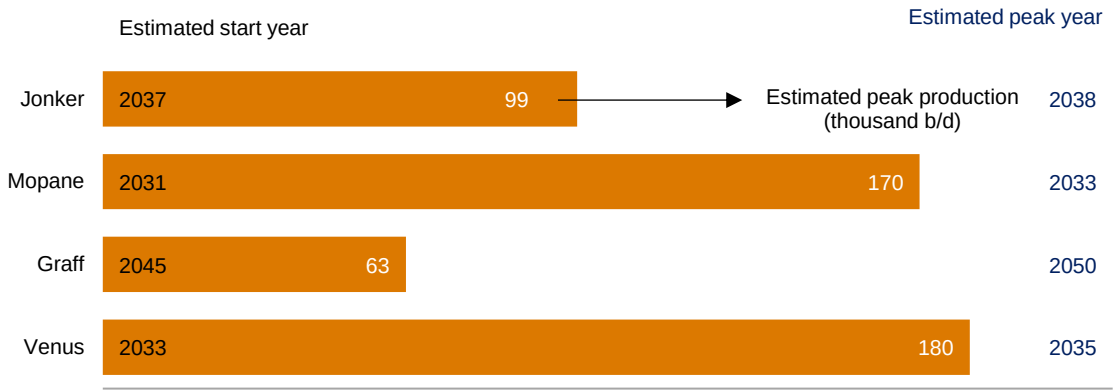
Data compiled: May 2025.
Source: S&P Global Commodity Insights.

Institutional changes under new Namibian government could complicate investment environment

Namibia's crude and condensate production by development (million b/d)



Namibia's major oil discoveries

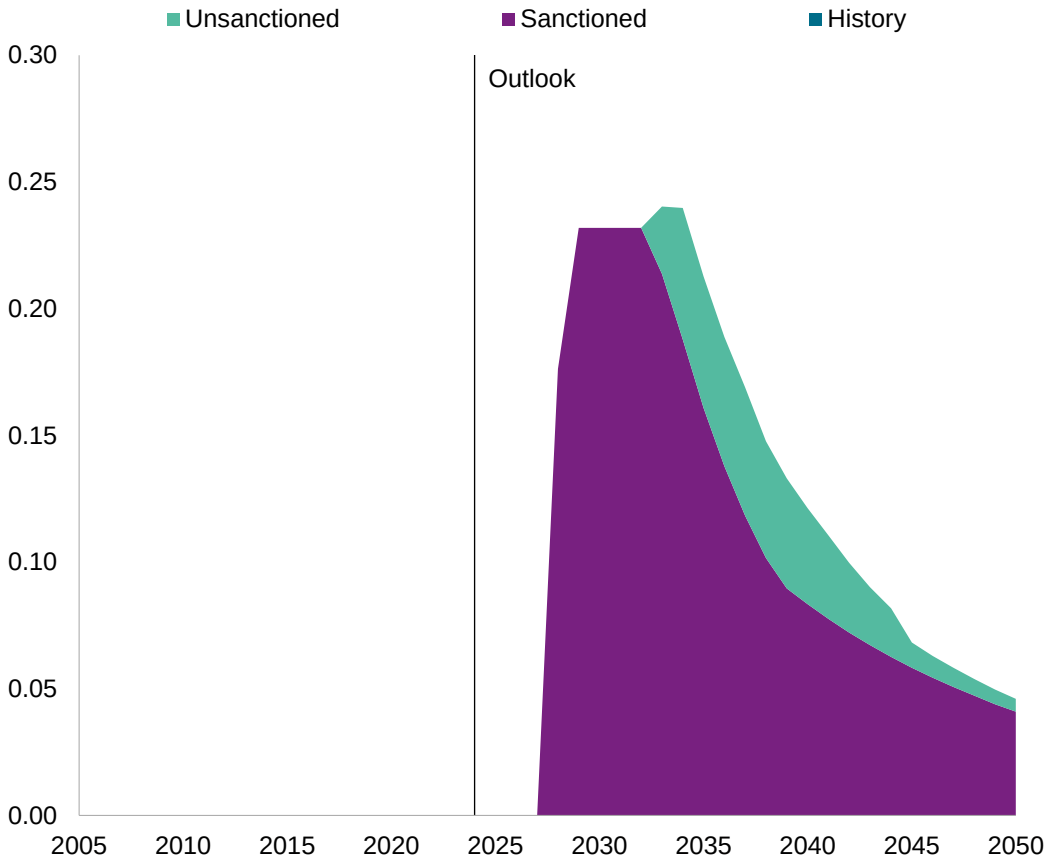


Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

- Shell PLC and TotalEnergies' respective Graff and Venus discoveries in Namibia's Orange Sub-basin in 2022 marked a significant turning point in the country's hydrocarbon sector. While the final investment decisions have not been made for these discoveries, they are estimated to hold several billion barrels of oil and gas resources. The exploration activity in Namibia continued with the Jonker discovery in 2023, followed by the Mopane and Mangetti 1X discoveries in early 2024.
- While the discoveries have rolled in, a caution flag was raised by Shell – describing its discoveries as viable non-commercial. Azule Energy's entrance into the Orange Sub-basin is further evidence of the excitement the discoveries have generated; however, Chevron's entrance into the Walvis Sub-basin indicates that international oil companies (IOCs) believe opportunities may exist in the north.
- The race to first oil is between TotalEnergies' Venus Oil Project and Galp's Mopane Oil Project. Both companies have mentioned targeting 2030, with Galp even suggesting an earlier start via an early production system.
- The total oil production in Namibia may reach a peak rate of 450,000 b/d around 2035 based on the current discoveries and estimated volumes.
- Namibia's upstream hydrocarbon sector is very accessible to foreign investors under an open-door approach to licensing. In her new, smaller cabinet, the President has separated the oil and gas portfolio from the wider natural resources sector and brought it directly under the presidency.The restructuring and the likely more stringent demands for domestic benefits will raise questions for foreign investors around decision-making, particularly given the country's limited institutional capacity.

Uganda expected to produce its first oil from the Tilenga and Kingfisher upstream oil projects in 2028

Uganda's crude and condensate production by development (million b/d)

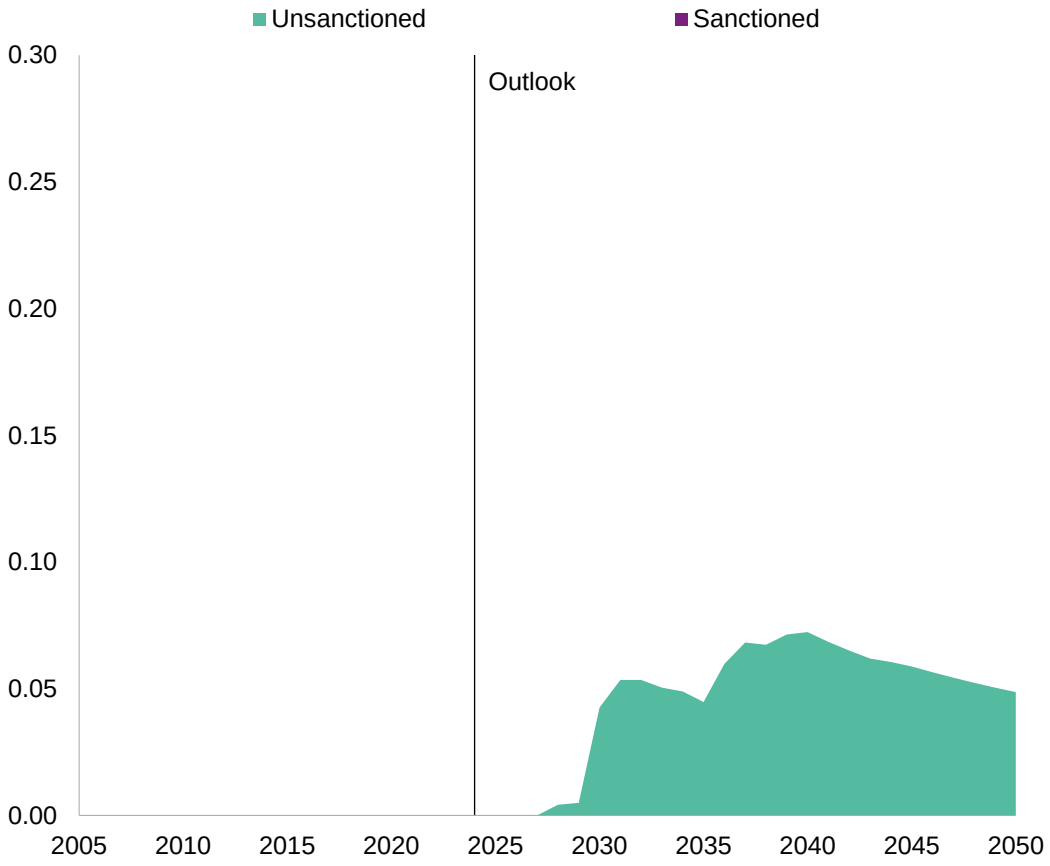


Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

- Uganda's crude oil production is anticipated to commence in 2028, with the Kingfisher and Tilenga projects expected to reach peak production levels of 40,000 b/d and 192,000 b/d, respectively. These projects are projected to sustain a production plateau of 230,000 b/d, for few years spanning 2029 until 2033.
  - The Tilenga project, operated by TotalEnergies, is Uganda's largest producing field, with an expected peak production of 190,000 b/d. The project encompasses six fields, including Jobi-Rii, Gunya, Ngiri, Kasamene-Wahrindi, Kigogole-Ngara, and Nsoga, with a Central Processing Facility (CPF) and a 95-km pipeline connecting to the Kabaale-Buseruka refinery. The Kingfisher field, operated by CNOOC, holds 2P recoverable reserves of 267.7 MMbbl of oil and includes a CPF and a 46-km pipeline linking to the refinery and export hub.
- The Kaiso Tonya project is expected to come online after 2030, contributing to the country's crude output. The sanctioned oil production is forecasted to peak around 2029 and gradually decline, while unsanctioned production remains relatively stable but shows a slight decline towards the end of the forecast period. The development of the Tilenga and Kingfisher fields involves the construction of the East African Crude Oil Pipeline (EACOP) to transport oil to Tanga harbor in Tanzania, with the pipeline expected to be operational by 2028.
  - TotalEnergies and CNOOC are the key players in Uganda's upstream sector, with significant investments in the Tilenga and Kingfisher projects. The EACOP project, initially expected to be funded by banks and financial institutions, has seen TotalEnergies and CNOOC increase their financial commitments due to challenges in securing external financing.

Senegal has recently joined the ranks of oil exporters with the commencement of production at Woodside's Sangomar field, yet the future growth remains uncertain

Senegal's crude and condensate production by development (million b/d)



- Senegal's crude oil production began in 2024 with the Sangomar field, operated by Woodside Energy, marking the country's entry into the oil-producing sector. The Sangomar field (Phase 1) achieved an average production rate of 48,200 b/d by in 2024. Looking ahead, Senegal's crude output is expected to rise to 80,000 b/d in 2025.
  - The Sangomar field, which began production in June 2024, is Senegal's largest producing field. Phase 1 of production is expected to peak in 2025, then decline leading up to 2030. Phase 2 is then expected to come online in 2030, with an initial capacity of 38,000 b/d before rising to 49,000 b/d in 2031.
- Beyond 2030, the Yakaar-Teranga gas development, operated by Kosmos Energy, is anticipated to come online, although it is still in the planning phase and unlikely to commence within the next three to four years. This project is expected to significantly contribute to the country's hydrocarbon production capacity.
- A proposed gas pipeline project by Morocco aims to connect Nigerian gas to West African markets and Europe, potentially enhancing Senegal's gas export capabilities. The country's existing refinery, revamped to process local Sangomar crude, covers a substantial portion of local demand, with plans to increase its feedstock from local production. These developments underscore Senegal's evolving role in the regional energy landscape.

Data compiled: May 2025.
Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

Other African countries highlights

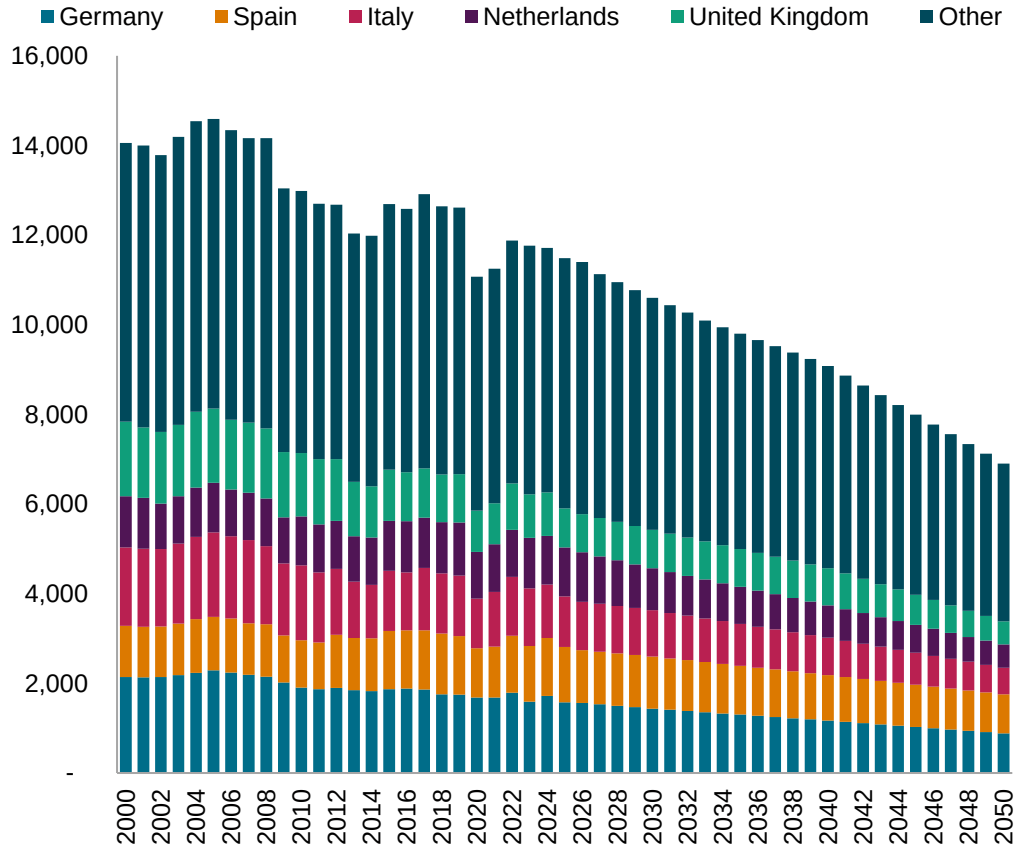
- **The extended duration of reduced prices following 2015 has delayed the approval of numerous deep-water projects in West Africa.** Consequently, production in Equatorial Guinea and Cameroon is anticipated to stagnate, as there are no significant projects currently planned.
  - In 2024, Cameroon produced an average of 62,000 b/d of crude oil, marking an 8% decrease from the previous year, continuing a downward trend observed since 2020. The decline is attributed to the natural depletion of mature fields, particularly in the Rio del Rey Basin. Looking ahead, crude production is expected to continue its decline unless new projects are sanctioned. Perenco and Addax Petroleum, the main producers, have been active in development drilling to mitigate this decline, but no major projects are expected to come online soon. The forecast suggests that without significant investment and exploration, production levels will struggle to maintain current outputs leading up to and beyond 2030.
  - Equatorial Guinea's crude oil production averaged 80,000 b/d in 2024, reflecting a significant decline from previous years due to a lack of investment in mature assets. The country's output was notably higher at 133,000 b/d in 2018. Looking ahead, a modest rebound in production is anticipated in the late 2020s, driven by infill development programs and potential new projects. However, without substantial investment, crude production is expected to continue its downward trend, potentially falling further in the 2030s. The Zafiro oil field, previously operated by ExxonMobil, is a key focus for maintaining production levels, with GEPetrol acting as the interim operator and planning a multi-phase development strategy. In 2024, the Zafiro Complex produced on average 22,000 b/d, accounting for around 28% of total production in Equatorial Guniea.
- **Kenya's crude oil production has yet to commence,** with Tullow Oil's Lokichar project paving the way for the country's first oil output. The project, consisting of four oil assets—Ngamia, Ekales, Twiga South, and Amosing—has an estimated total 2P recoverable reserve of 640 million barrels. Production is anticipated to begin before 2030, reaching peak output at 120,000 b/d. The development is expected to have a lifespan of approximately 19 years if production targets are met.
  - The Lokichar project is the sole development program in Kenya, with Tullow Oil actively seeking partners to execute the project. The revised Field Development Plan (FDP) is due for submission in mid-2025, with first oil production contingent on securing a partner by that time.
- **In 2024, Côte d'Ivoire's crude oil production was marked by significant developments**, with the Baleine field playing a pivotal role. The country's output averaged around 52,000 b/d in 2024, a 53% increase on 2023 levels, primarily driven by increased production from the Baleine field, which accounted for over 40% of the total crude production in Côte d'Ivoire in 2024. Niger’s production remained stable in 2024 at 108,000 b/d. Looking ahead, production is expected to remain at the same level throughout the medium-term, with no future projects expected to come online until the 2030s.

Source: S&P Global Commodity Insights. E&P Terms and Above-Ground Risk

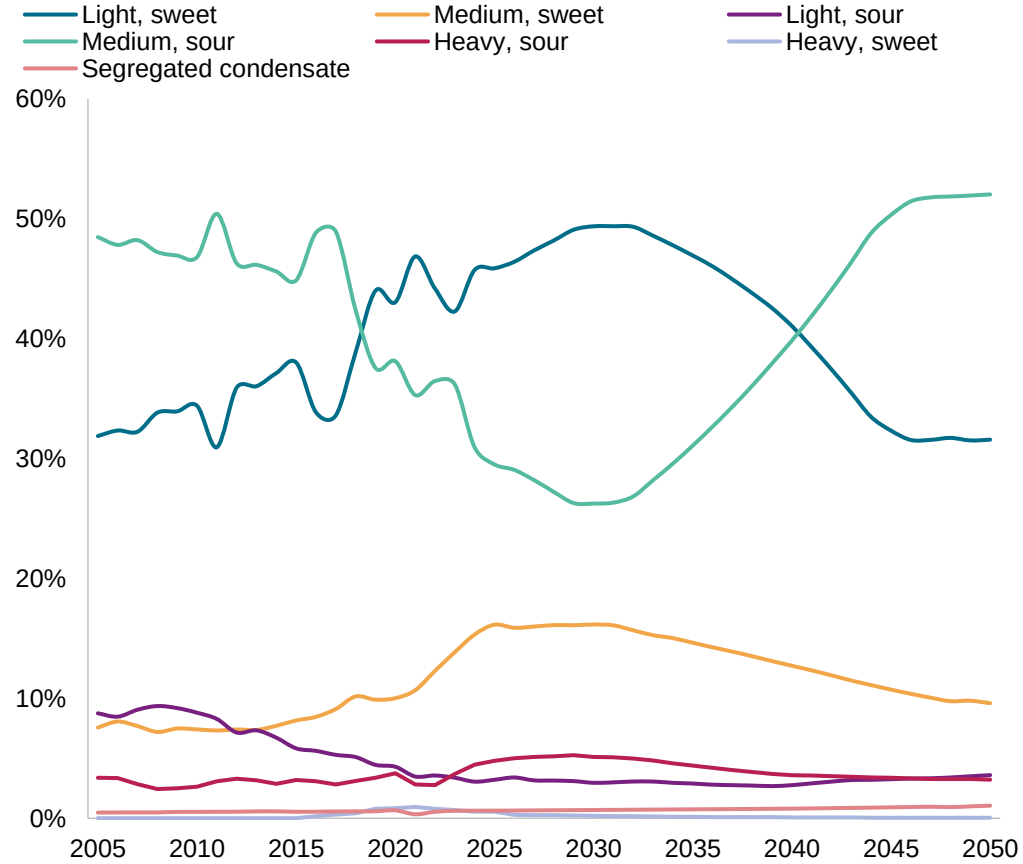
Crude runs and quality

European runs expected to fall significantly, as regional demand falls sharply on environmentally-driven push away from fossil fuels and industrial weakness

Refinery crude and condensate runs in Europe (thousand b/d)



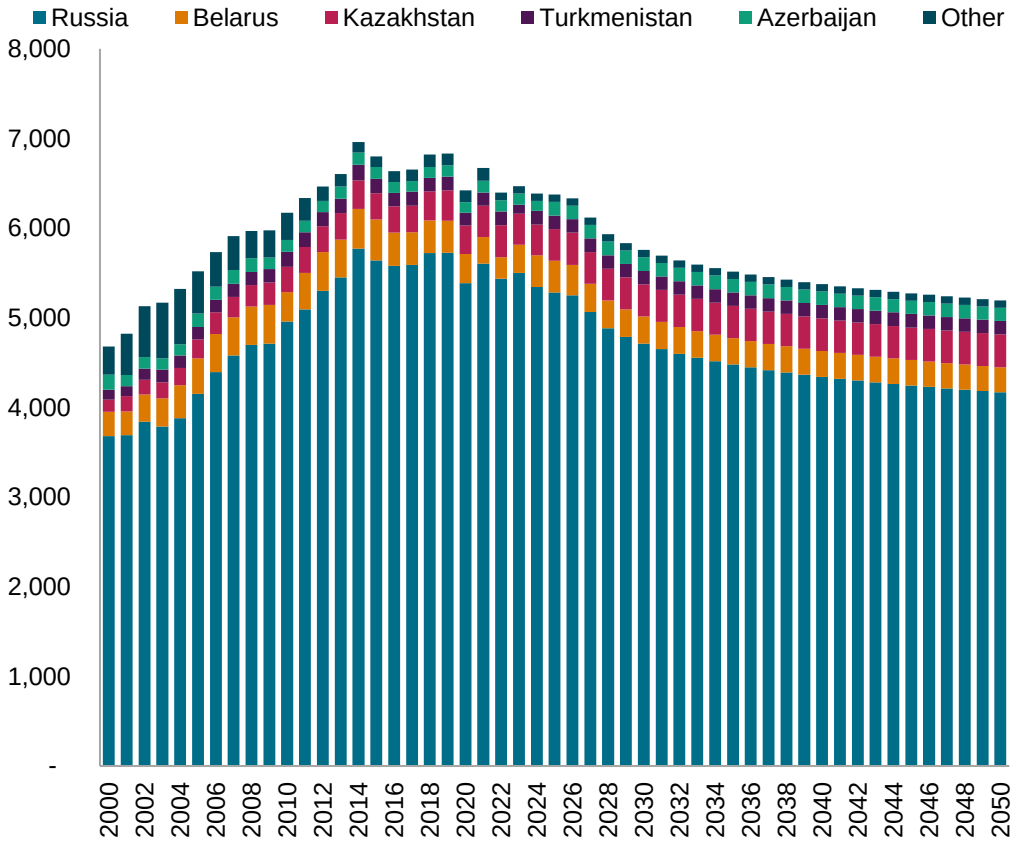
Europe runs by crude type



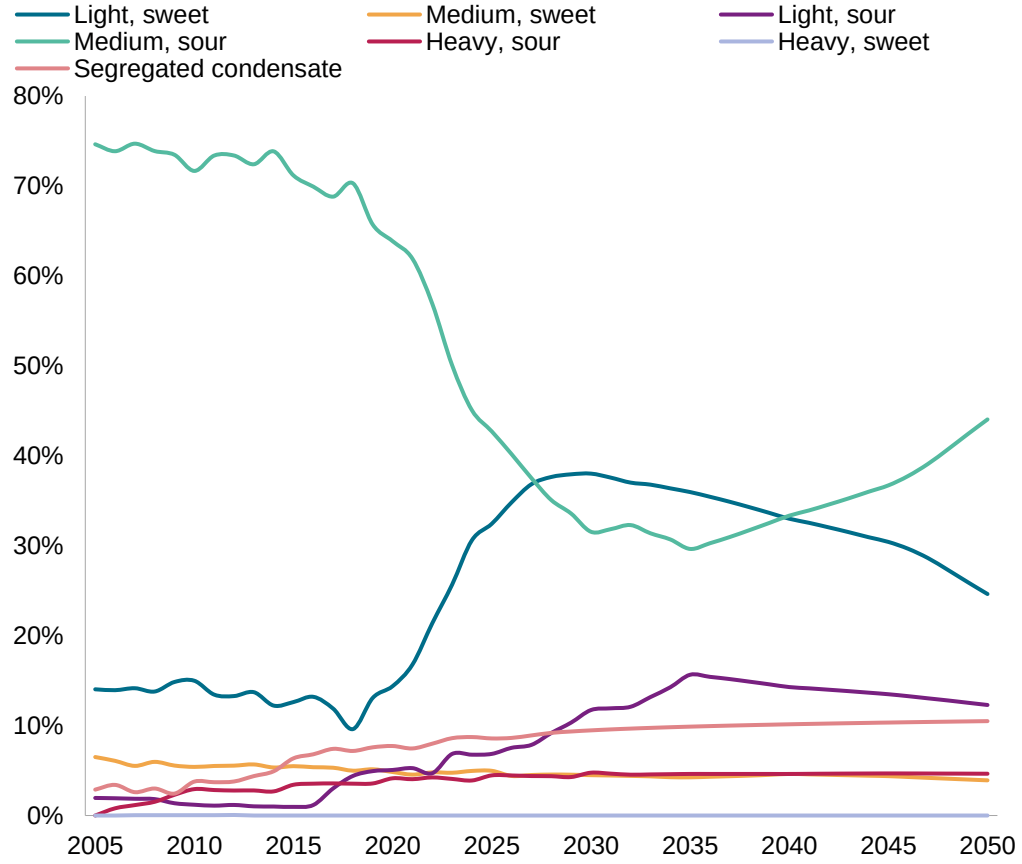
Data compiled: May 2025.
Source: S&P Global Commodity Insights

Russia dominates refinery runs in the region, with over 80%. Outlook is for regional runs to gradually decline, from 6.4 million b/d to 5.2 million b/d by 2050.

Refinery crude and condensate runs in CIS (thousand b/d)



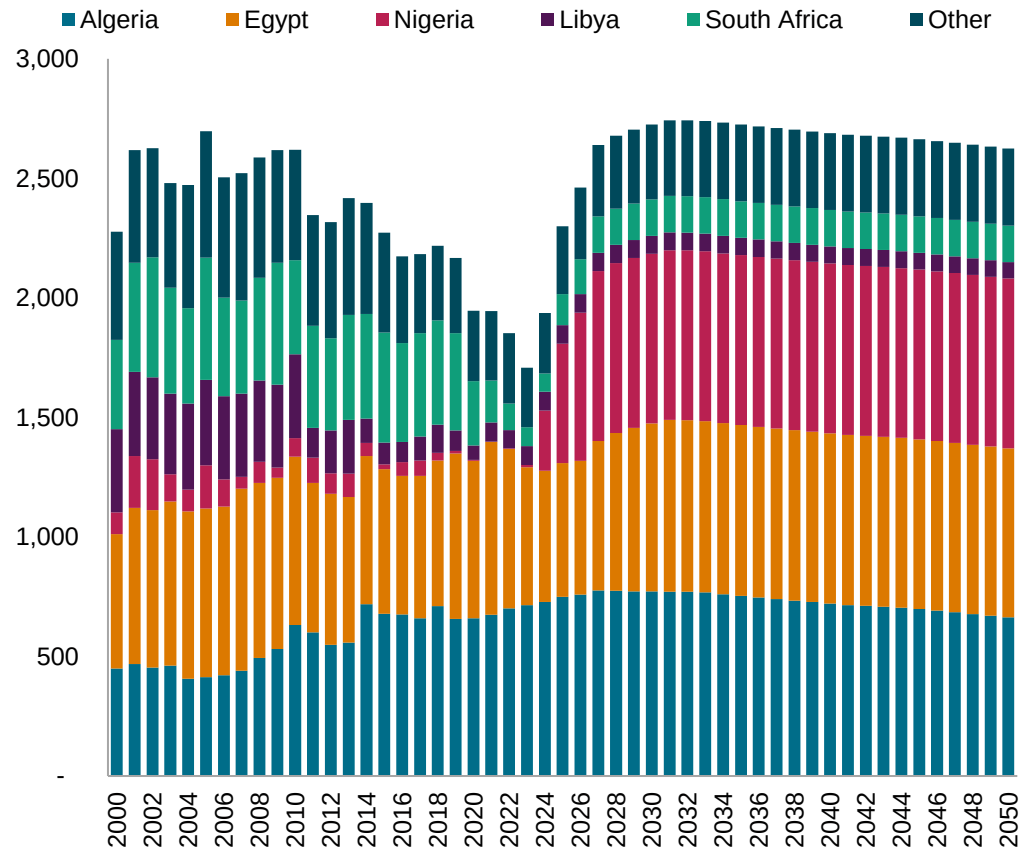
CIS runs by crude type



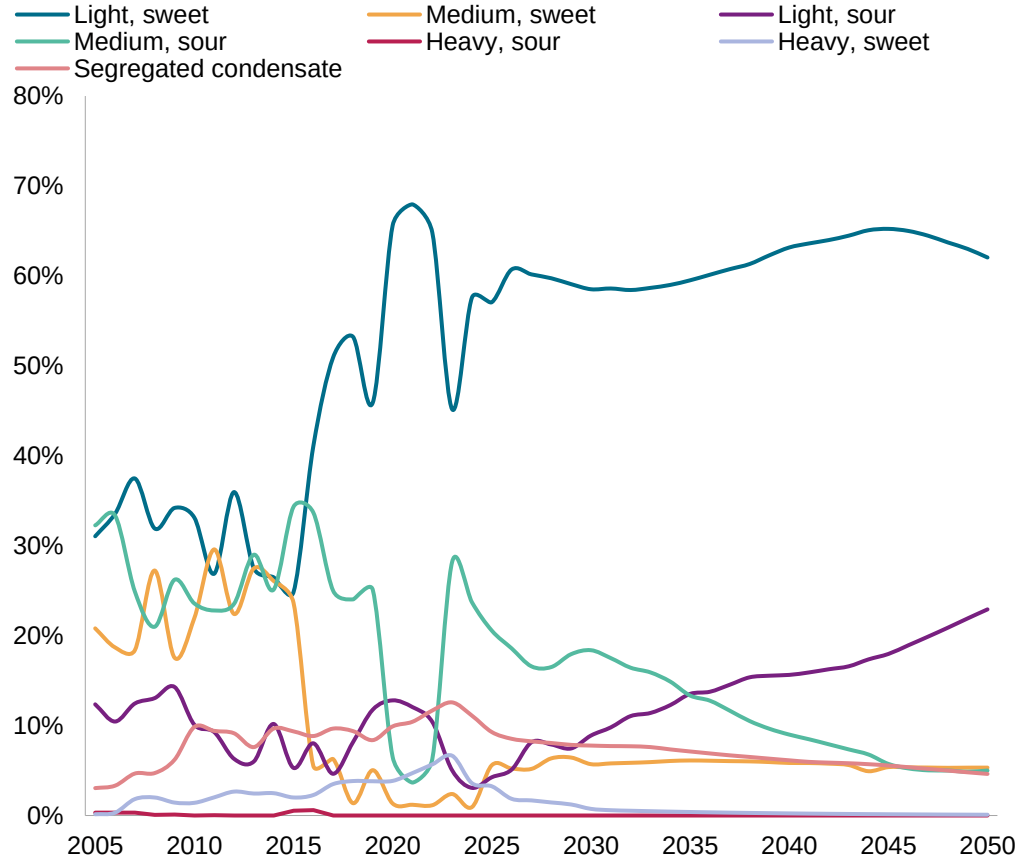
Data compiled: May 2025.
Source: S&P Global Commodity Insights.

African refinery runs get major boost from Dangote streaming, but the region will struggle to raise runs higher longer-term on lack of substantial new builds

Refinery crude and condensate runs in Africa (thousand b/d)



Africa runs by crude type



Data compiled: May 2025.
Source: S&P Global Commodity Insights

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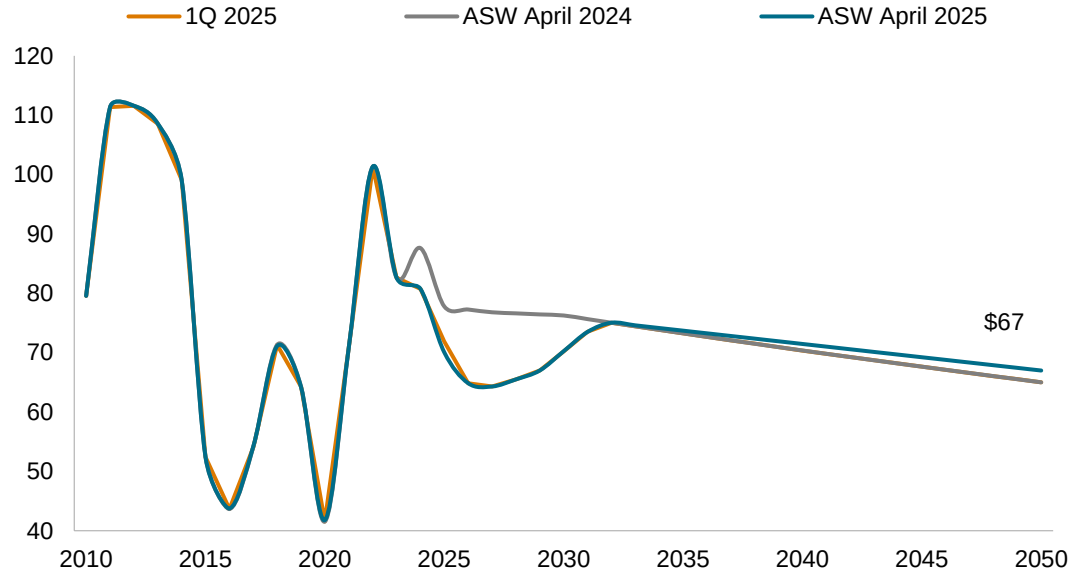
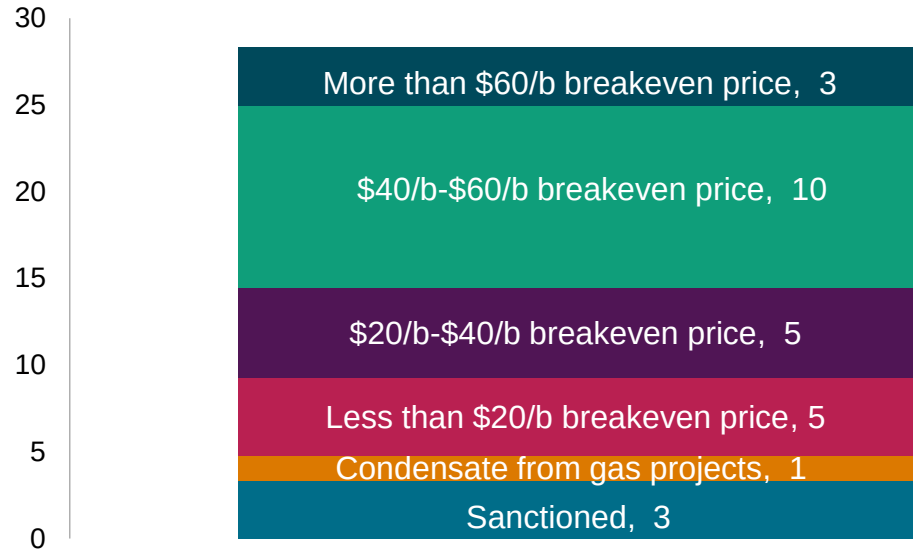
Crude pricing

Long-term Brent price expected to fall to $67/b (real terms) by 2050, consistent with the cost of the marginal barrel needed to clear demand

Dated Brent crude price outlook (constant 2024$/b)



Cost of supply by break-even price in 2050 (million b/d)



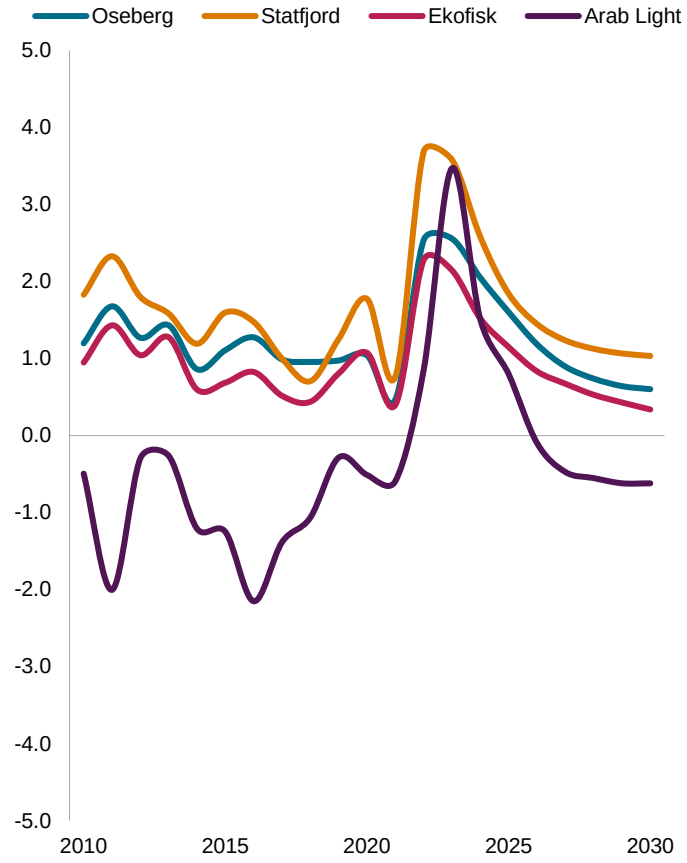
The Brent price outlook: We have increased our long-term Dated Brent price from $65 in 2050 to $67 based on our analysis of the marginal layer of supply, which is largely below $70. By 2050, the price-setting marginal barrel is expected to come from Deepwater Brazil, the US Gulf of Mexico, and higher-cost US tight oil. We still anticipate a buildup of crude inventory in 2026, fueled by production growth in the Americas while remaining in check due to supply growth outside OPEC+. We expect OPEC+ to return some oil to the market, led by the UAE's higher quota and continued non-compliance by other members. WTI is expected to remain below $70 through 2030, leading US producers to pull back on upstream spending, which slows overall US production to manage global crude oil surpluses as overall crude oil demand declines.

Beyond 2026, the year-on-year crude deficit gradually reduces inventory by 2032, encouraging Dated Brent prices to slowly rise back to $75/b in 2032. The average Dated Brent price from 2025-2050 is $70/b.

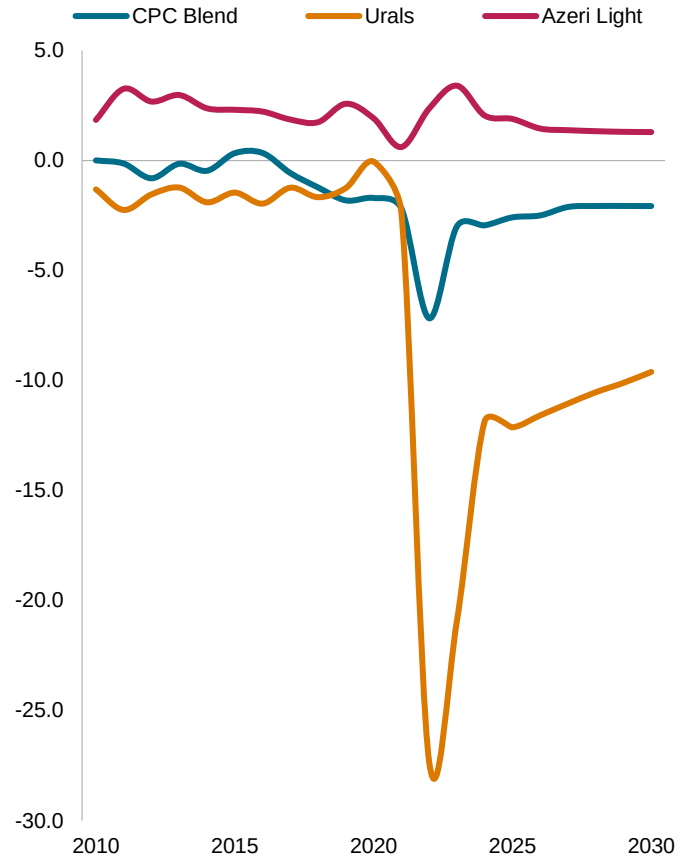
Data compiled: May 2025.
Source: S&P Global Commodity Insights.

Light sweet crude differentials in Europe are set to fall as European runs decline, while West African crudes expected to be supported by Dangote demand

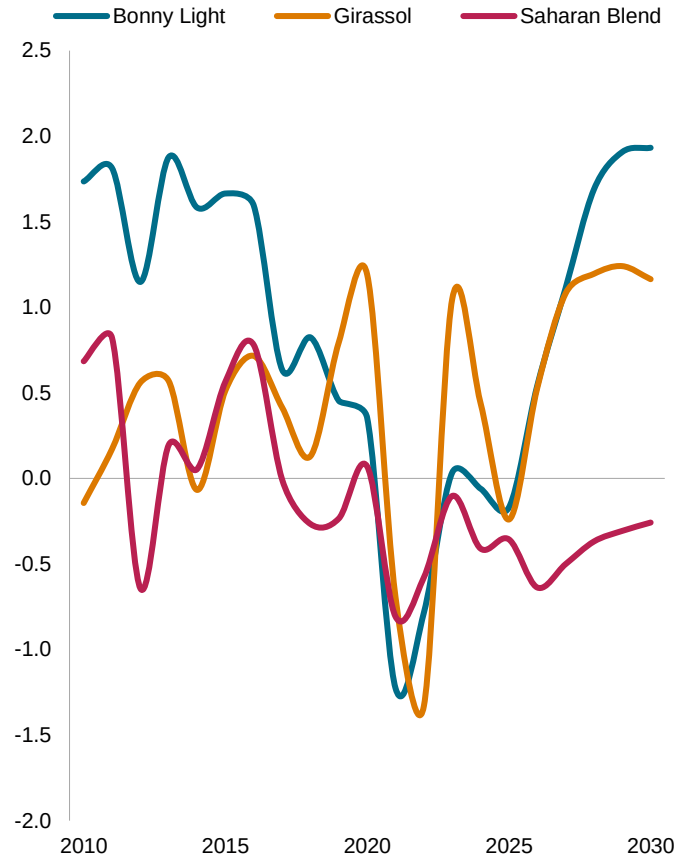
Crude price differentials to Dated Brent ($/b)



Crude price differentials to Dated Brent ($/b)



Crude price differentials to Dated Brent ($/b)

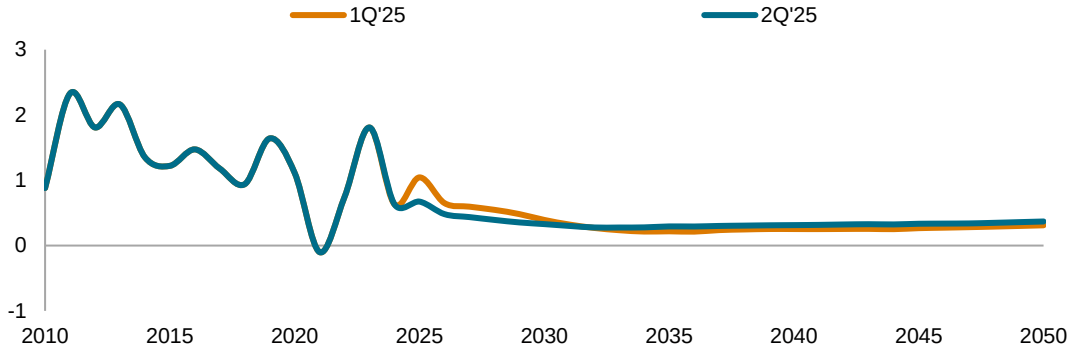


Data compiled: May 2025.
Prices are in constant 2024 US dollars.
Source: S&P Global Commodity Insights.

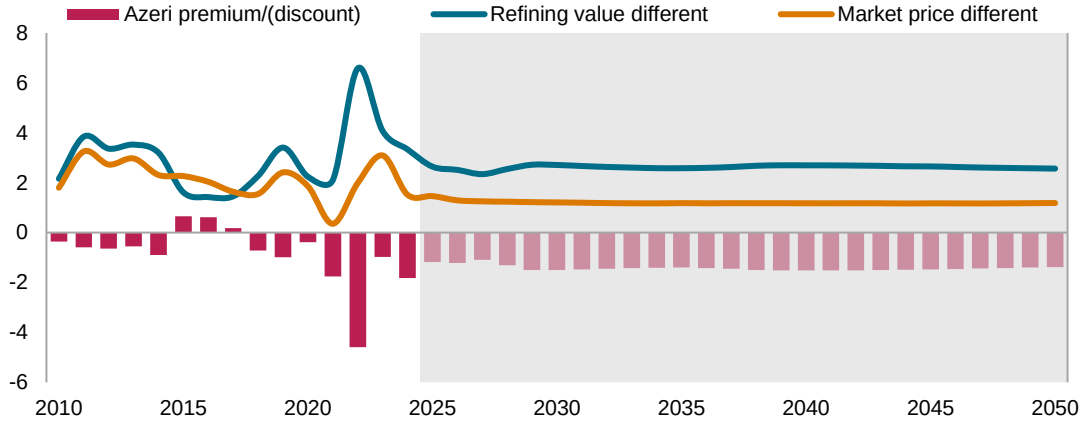
S&P Global
Commodity Insights

Azeri Light differential to Dated Brent expected to decline in the near-term amid weaker distillates with a brief recovery by decade's end

Azeri BTC Blend Northwest Europe vs. Dated Brent (Constant 2024 $/b)



Azeri BTC Blend Northwest Europe vs. Dated Brent (assuming Forties quality) ($/b)

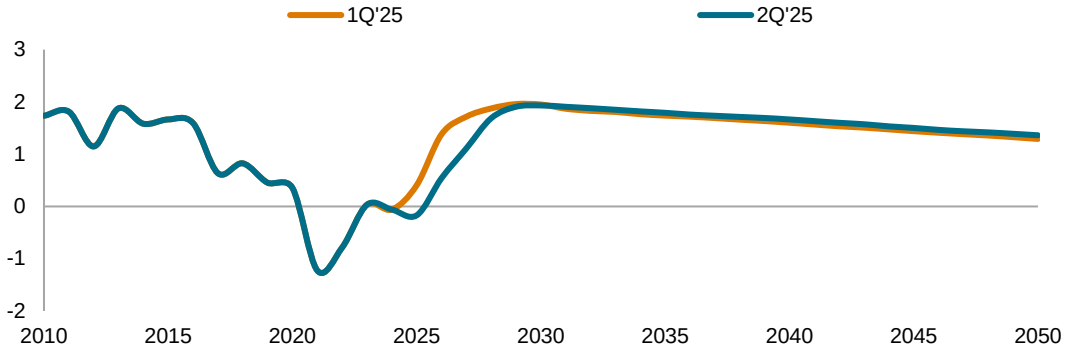


Data compiled: May 2025.
BTC = Baku-Tbilisi-Ceyhan, BFOET = Brent, Forties, Oseberg, Ekofisk and Troll
Calculations are on a delivered basis to Rotterdam.
Source: S&P Global Commodity Insights.

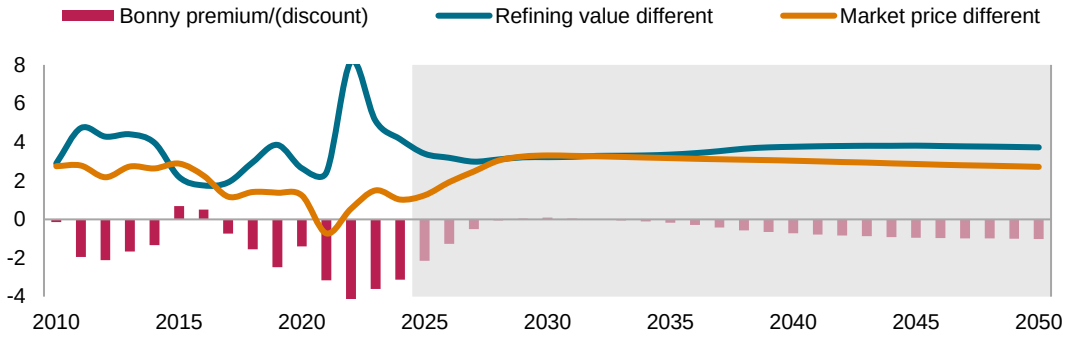
- The spread between Light sweet Azeri crude and Dated Brent has been adjusted downward due to a decline in demand, abundant crude supply from the United States, and elevated freight rates in the region. Despite these factors, we anticipate a modest increase in Azeri Light prices in 2025. This is expected to coincide with the ramping-up to commercial operation at the Dangote refinery, which will attract substantial volumes of light sweet crudes, thereby reducing availability in the market.
- As we approach the latter years of the decade, Azeri Light is poised to benefit from stronger refining values driven by robust demand for middle distillates and low-sulfur bunkers. However, the anticipated rise in naphtha demand from early next decade is likely to favour BFOET crudes over Azeri Light.
- By the mid-2030s, Europe is projected to become a net exporter of diesel, intensifying competition for market share in Africa and Latin America against exports from the United States and the Middle East. This shift is not expected to provide any additional support to Azeri Light prices.

Bonny Light crude faces near-term pressure owing to weak diesel outlook and long-term price stagnation amid changing market dynamics

Bonny Light - Dated Brent spread (Constant 2024 $/b)



Bonny Light vs. Dated Brent (assuming Forties quality) ($/b)

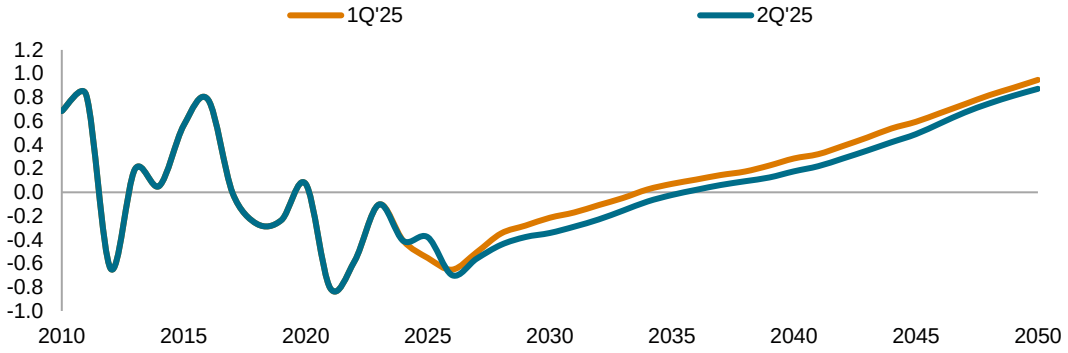


- The outlook for West African crudes, including Bonny Light, has been revised downward in the near term due to a challenging freight environment and sluggish demand. Additionally, the anticipated decline in diesel crack spreads is expected to exert further downward pressure on Bonny Light and similar crudes. As a result, Bonny Light's refining values are projected to weaken relative to Dated Brent, driven by a softer distillate market. However, its market discount is expected to narrow as the Dangote refinery progresses beyond its initial phase and ramp-up operations, tightening West African crude oil balances starting in 2025.
- In the longer term, Bonny Light's market price differential is anticipated to steadily decrease due to ample availability and a preference for crudes rich in naphtha over those rich in distillates. Towards the end of the forecast period, Bonny Light prices are expected to stagnate, with the majority of exports directed to Europe, a smaller portion to the Far East, and minimal exports to the United States. Notably, USEC FCC Bonny Light margins are projected to turn negative from the early 2040s.

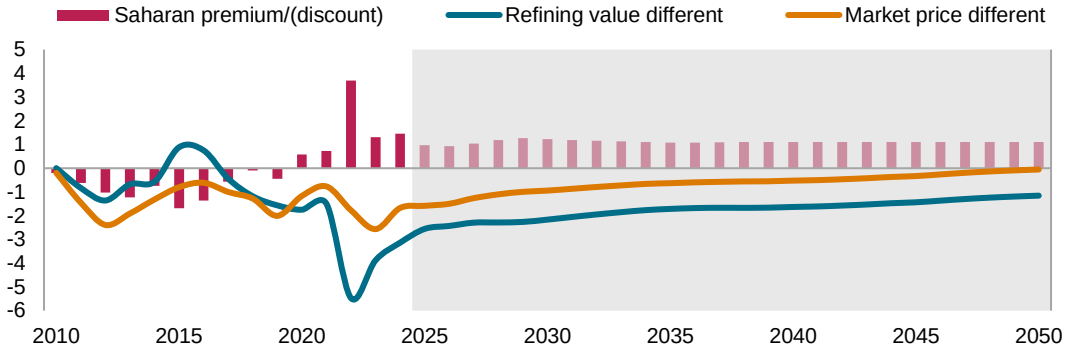
Data compiled: May 2025.
Calculations are on a delivered basis to Rotterdam.
Source: S&P Global Commodity Insights.

Saharan Blend crude faces near-term weakness with long-term support from naphtha crack spreads

Saharan Blend vs Dated Brent (Constant 2024 $/b)



Saharan Blend vs. Azeri Light ($/b)

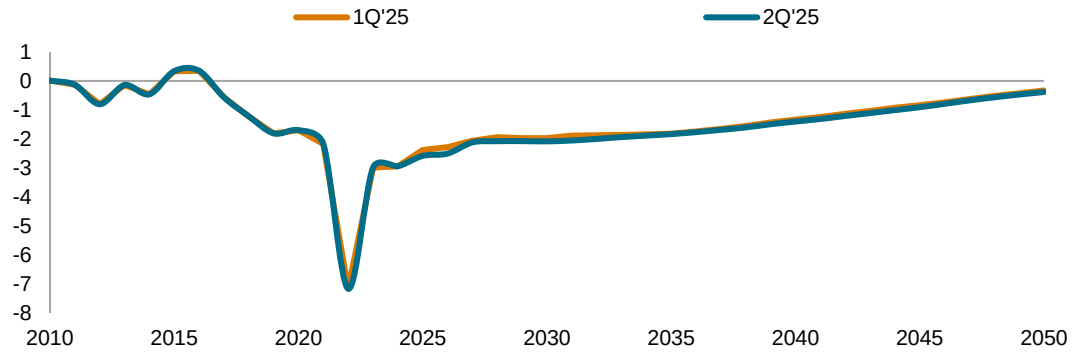


- In the near term, Saharan Blend, known for its rich naphtha content, is anticipated to weaken, with its differential to Dated Brent expected to reach a low point in 2026.
- Naphtha crack spreads are projected to remain influenced by the growing Asian market, which is set to see significant growth until 2030. By the late 2020s, European crack spreads are forecasted to transition to a structural premium, positively impacting Saharan Blend crack spreads from 2027 onward.
- In the long term, the naphtha crack spread is expected to continue supporting Saharan Blend, resulting in a delivered price by 2050 with a roughly $1/b premium over Azeri Light.

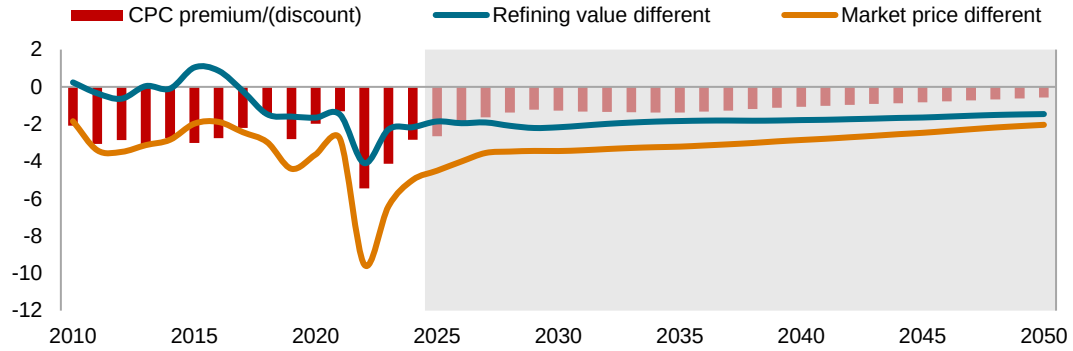
Data compiled: May 2025.
Calculations are on a delivered basis to Rotterdam.
Source: S&P Global Commodity Insights.

CPC Blend, like Saharan Blend, anticipated to gain long-term support from Asia's robust naphtha market, despite near-term weakness due to large availability

CPC Blend vs Dated Brent (Constant 2024 $/b)



CPC Blend vs. Azeri Light ($/b)

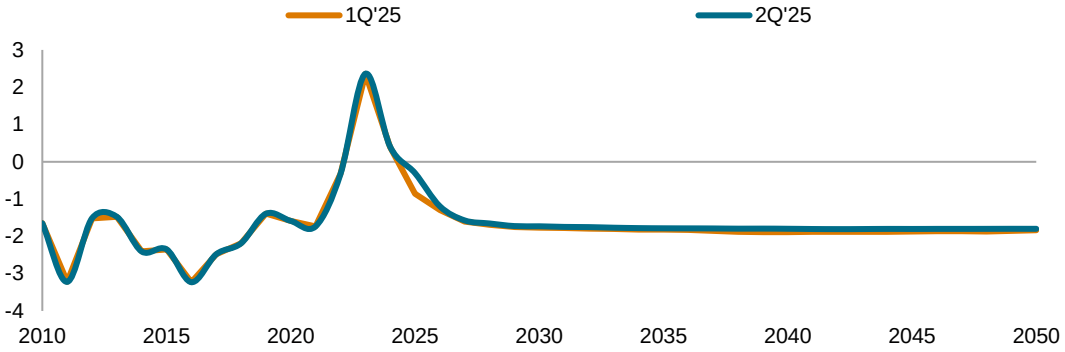


- In the near term, CPC blend become cheaper following the ramp-up of a Chevron-led expansion of the giant Tengiz project, resulting in a slight widening of its differential to Dated Brent.
- Fundamentally, CPC Blend shows a discount to Saharan Blend to facilitate the eastward shift of surplus, driven by its large availability and decreasing refinery runs in Europe. Typically, CPC Blend is marketed with a roughly $2/b discount to Saharan Blend, reflecting its higher mercaptans content.
- Similar to Saharan Blend, CPC Blend is rich in naphtha, and its price is anticipated to receive support from the early 2030s, when naphtha crack spread are expected to shift to a structural premium relative to dated Brent

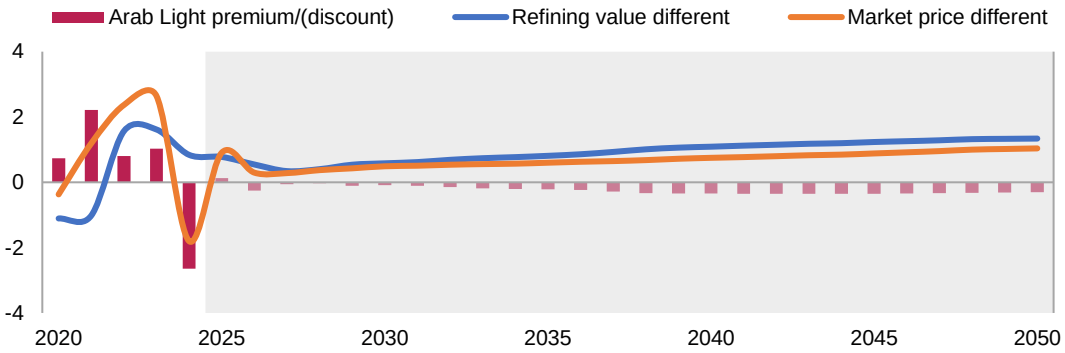
Data compiled: May 2025.
Calculations are on a delivered basis to Rotterdam.
Source: S&P Global Commodity Insights.

Arab Light's differential to Dated Brent to decline near term amid OPEC+ production growth, while the long–term forecast continue to show strength

Arab Light - Dated Brent spread (Constant 2024 $/b)



Arab Light vs. Johan Sverdrup Northwest Europe ($/b)

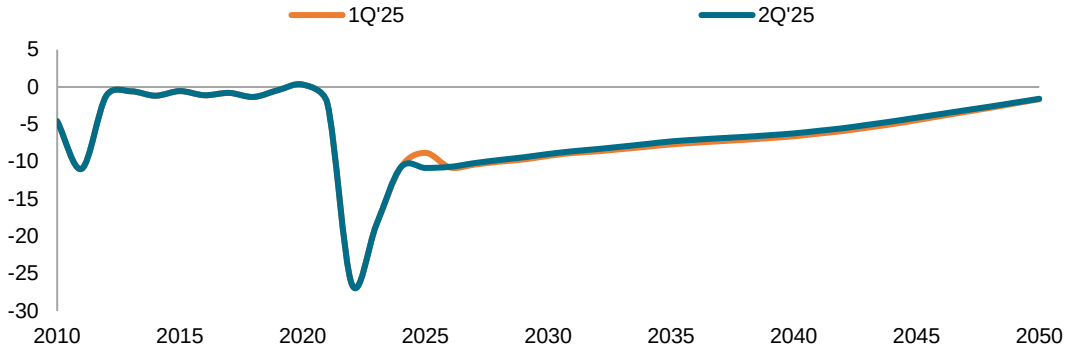


- The Arab Light differential to Dated Brent is expected to narrow in 2025 due to US sanctions on Russian crude exports and increased US pressure on Iran, which will both support the Middle Eastern market. Despite this, the Official Selling Price (OSP) is declining as OPEC+ unwinds production cuts, leading to a slightly negative crack spread to Dated Brent in 2025, with expectations of further negativity as the decade progresses.
- Arab Light typically commands a market premium over Urals relative to their catalytic cracking parity. Fuel-oil cracks are likely to remain strong in the medium term, supported by supply tightness resulting from a lighter global crude slate. This will maintain the strength of Arab Light in the medium to long term, with its differential to Dated Brent remaining at the upper range of pre-pandemic levels.
- Nevertheless, an aggressive production ramp-up by OPEC+ could lower oil prices and potentially reduce non-OPEC+ production, tightening the light crude market. This could result in a lower differential than currently projected.

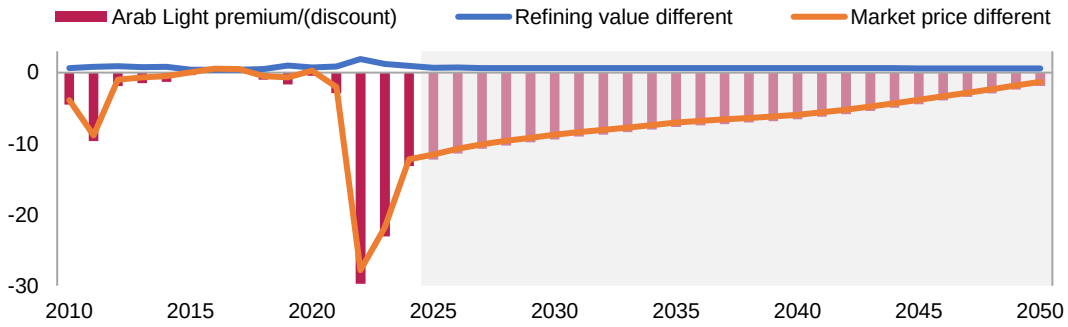
Data compiled: May 2025.
Calculations are on a delivered basis to Rotterdam.
Source: S&P Global Commodity Insights.

Urals discounts to Dated Brent persist beyond historical levels, while Arab Light maintains structural premium over Urals

Urals Med vs Dated Brent (Constant 2024 $/b)



Urals Med vs. Arab Light ($/b)



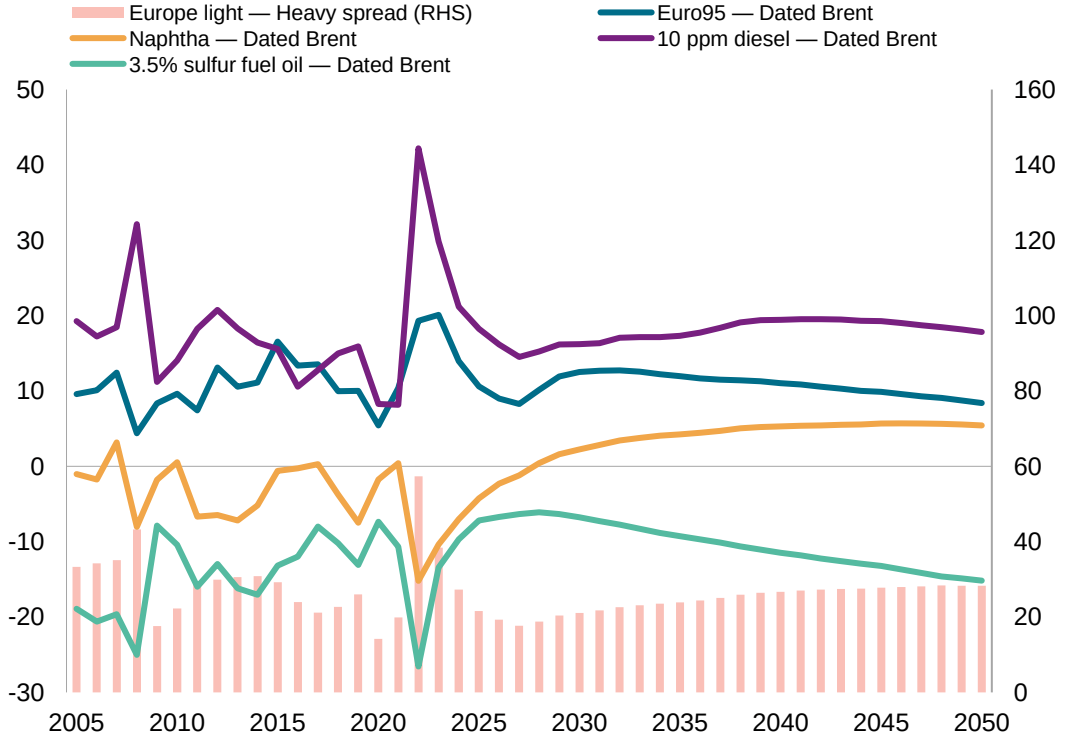
- Various sanctions imposed on vessels utilized for transporting Russian barrels have led to higher costs related to trade of Russian oil, exerting downward pressure on Urals prices in the near term. Additionally, the lack of liquidity in the European market for Urals has made assessed values particularly sensitive to freight rate fluctuations.
- In the medium term, the price difference between Urals and Arab Light is narrowing due to reduced Russian output. The deeper market price discount compared to refining values reflects sellers' motivation to clear surplus supply towards the east. As Russian supply decreases, the discount in the Urals market is expected to diminish, and the price difference between Brent and Urals is anticipated to narrow from the highs observed in 2022–24.

Data compiled: May 2025.
Calculations are on a delivered basis to Rotterdam.
Source: S&P Global Commodity Insights.

Long-term price forecast for Europe shows gasoline and naphtha converging

Diesel cracks to decline in the near term in line with new capacity and stagnating global demand growth, while long-term gasoline and naphtha cracks reflect the electrification of the car fleet and continued strong petrochemical appetite

Northwest Europe crack spreads (constant 2024 $/b)



Data compiled: May 2025.
RHS = right-hand side; ppm = parts per million.
Source: S&P Global Commodity Insights.

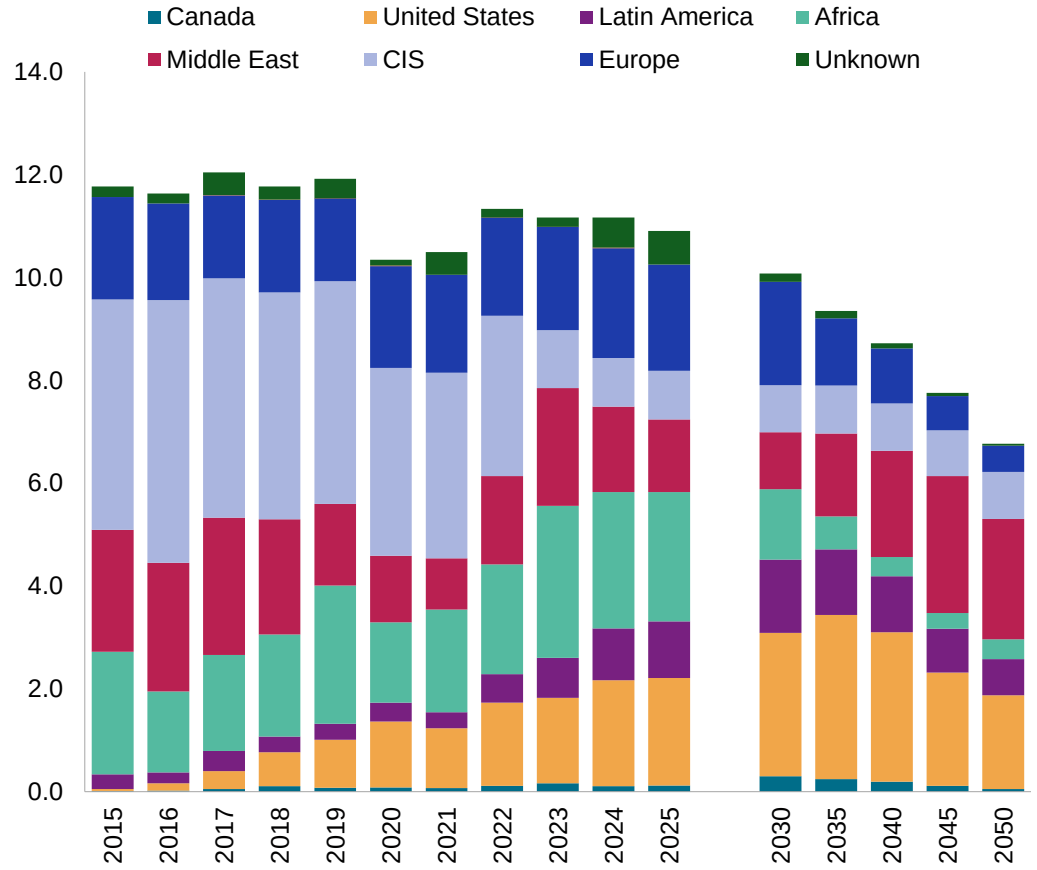
- **Gasoline** cracks are expected to collapse in the near term from current strength amid new capacity additions in key export markets. In the long term, car sales will continue to shift to alternative powertrains, in part accelerated by increasing pressure from emissions targets and bans on internal combustion engines, which will significantly affect gasoline demand. After the margin rebound around 2030, gasoline cracks will begin to decline again, dipping below $8/b by 2050.
- **Gasoil/diesel cracks** are expected to weaken significantly through 2027 from current high levels owing to incremental supply from east of Suez. From the early 2030s, diesel cracks will increase modestly on the of back carbon costs before stabilizing during the last decade despite declining European diesel demand. After becoming a net exporter, Europe will have to compete for market share in import regions, keeping downward pressure on cracks.
- **Naphtha crack spreads** remain price takers from the growing Asian market, set to increase strongly until 2030, mainly owing to a lack of alternative steam cracker feedstocks to meet high demand for plastics and fibers. European cracks are expected to flip to a structural premium by the late 2020s.
- In the near term, we expect the **3.5% sulfur fuel oil crack** to strengthen from negative $27/b in 2022 to the negative $7-$6/b range in the second half of the decade. Through 2030, global crude supply growth is predominantly light sweet crude from the Permian. As a result, the overall demand for vacuum bottoms increases relative to the available supply, making high-sulfur fuel oil (HSFO) stronger. From the early 2030s onward, our sour residue balances show that medium/heavy sour crude supply growth and decarbonization of shipping and stationary sectors would depress HSFO cracks once again, in order to incentivize further deep conversion capacity additions, most likely creep projects.

Crude trade

European crude oil imports are rewired after the European Union's ban on most Russian oil, with CIS regional market share dropping from above 40% to >10%

- **Russia, formerly supplying up to 45% of Europe's crude oil imports, lost its role as major supplier in the wake of the invasion of Ukraine, and ensuing sanctions.**
  - In response to Russia's invasion of Ukraine, the European Union imposed sanctions targeting Russian oil. A key measure was the ban on seaborne imports of Russian crude, effective December 5, 2022, followed by a ban on refined products on February 5, 2023.
  - These actions – still in force - aimed to reduce EU dependence on Russian energy and limit Russia's oil revenue. Our forecast does not assume return of volumes through 2050.
  - The sanctions have prompted Russia to redirect exports to Asia, particularly China (mainland) and India, while Europe increased imports from the US, Middle East, and Africa.
- Other CIS light, sweet grades from Central Asia (e.g., BTC Blend, CPC Blend, Azeri Light) will continue to grow.
- US exports to Europe (mostly light, sweet) are expected to increase to about 2.8 million b/d by 2030, around 28% of imports, while Middle Est will account for ~11%.
- **Europe's import requirement – excluding intra-European trade – will fall to around 8 million b/d by 2030 and reduce further to an estimated 6.2 million b/d by 2050**.

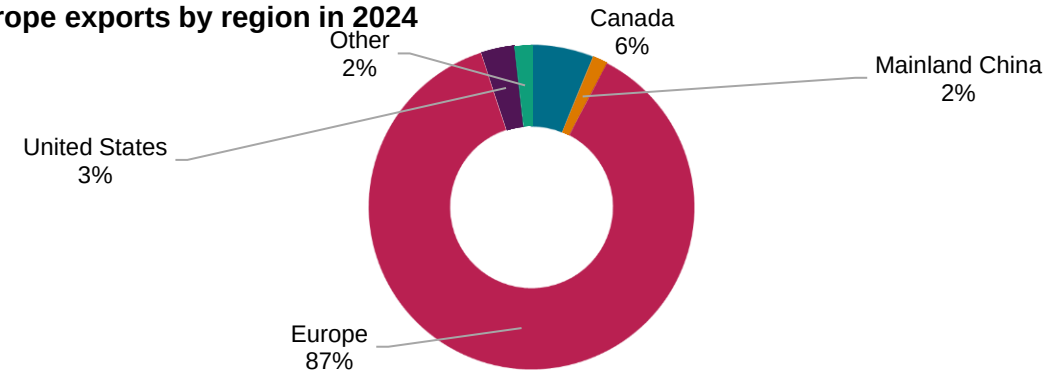
Europe crude and condensate imports (million b/d)



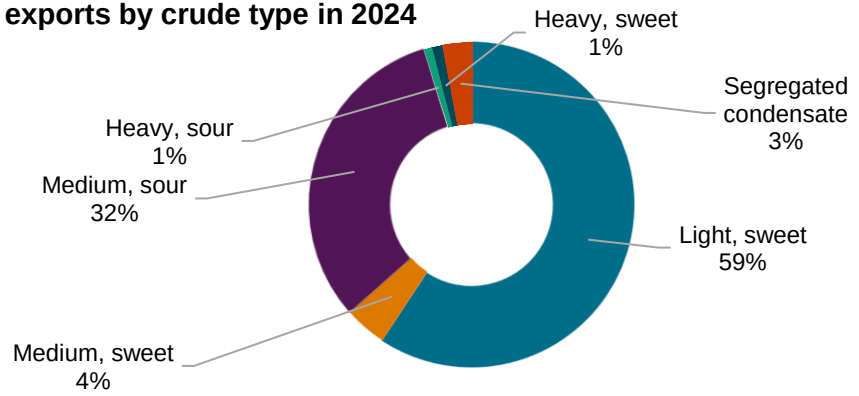
Data compiled: May 2025.
Source: S&P Global Commodity Insights.

European crude exports by quality and regional destination

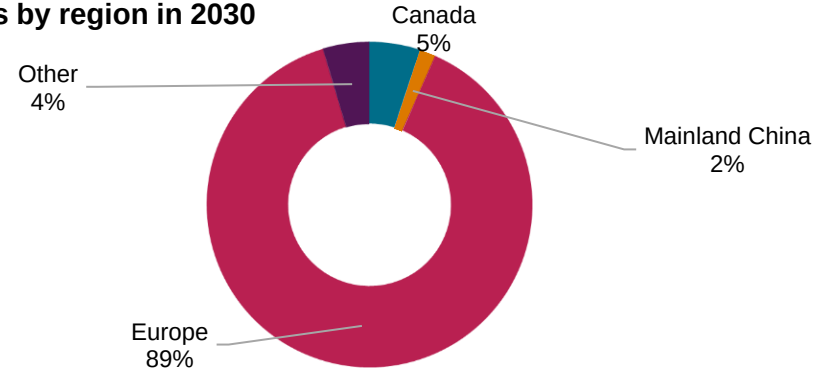
Europe exports by region in 2024



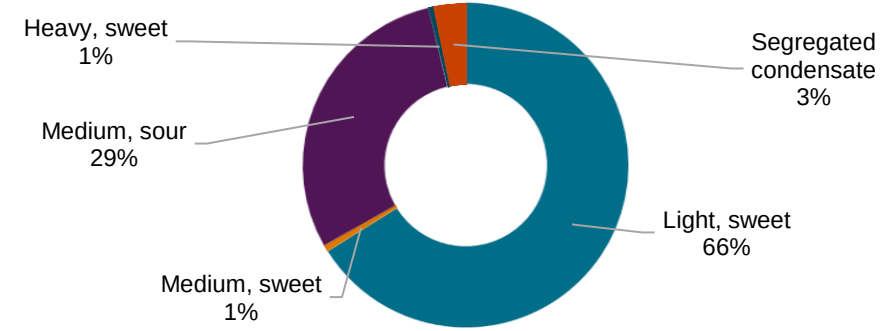
Europe exports by crude type in 2024



Europe exports by region in 2030



Europe exports by crude type in 2030

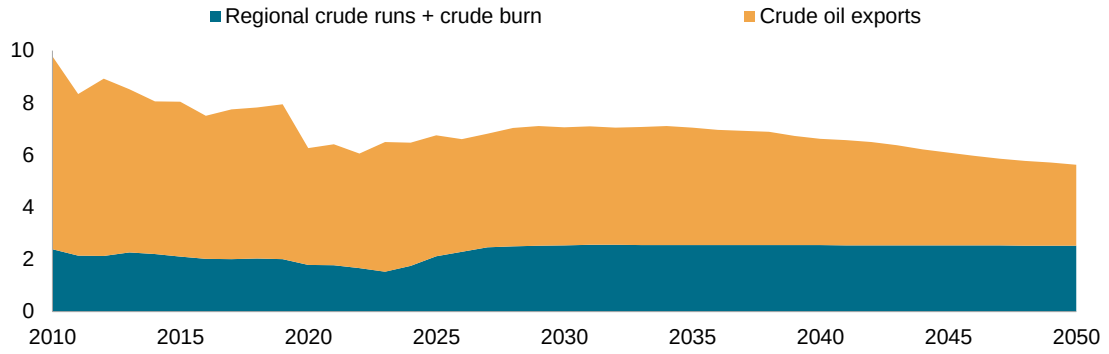


Data compiled: May 2025.
Source: S&P Global Commodity Insights.

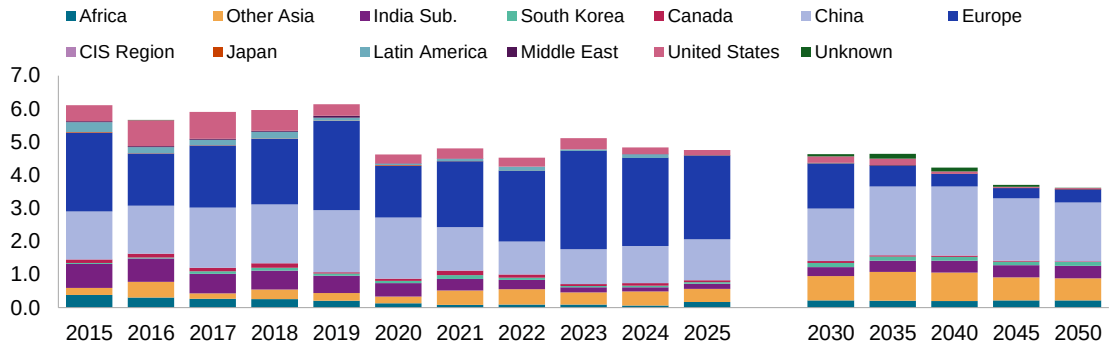
African crude trade to remain dominated by light sweet exports, with Asia a key destination

- Africa exports more crude than it imports — but the picture varies significantly by subregion. West Africa, North Africa, and parts of Central Africa are major exporters, while South Africa, East Africa, and some refining-deficient countries are importers.
- Intra-African trade is rising, driven by new refining projects and regional fuel demand, however Africa will remain a major exporter of light, sweet crude over the outlook horizon.
  - The newly established Dangote mega-refinery, which has a nameplate capacity of 650,000 b/d, has primarily relied on Nigerian light and medium sweet crudes, along with crude oil from the United States. We anticipate that the refinery will begin importing a broader variety of crudes once it reaches full capacity.
- Local production is based on light, sweet grades. There has been a sea change in trade flows from Africa in response to the rise of light, sweet shale production in the United States, with African exporters compensating for declining market share in the US by shifting volumes to Eastern markets like mainland China, India, and other parts of Asia.
- We expect this trend to continue as US shale growth rebounds this decade and as Asian domestic light, sweet crude continues to decline.
- Mainland China currently takes around a quarter of all African exports – this share will rise to exceed 50% by 2040, as Europe's import requirement is reduced.

Africa domestic crude oil disposition (million b/d)



Africa crude and condensate exports (million b/d)

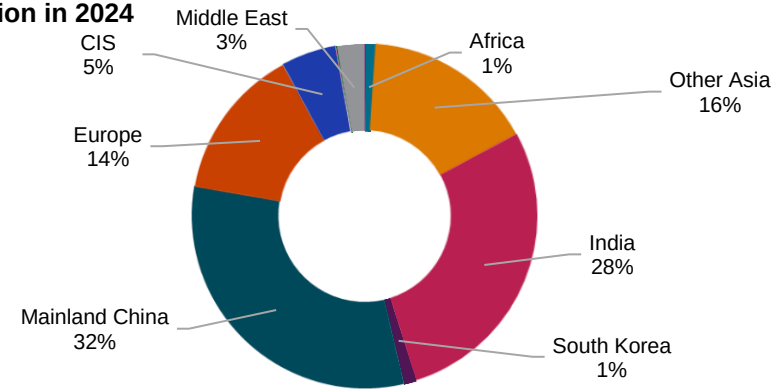


Data compiled: May 2025.
Source: S&P Global Commodity Insights.

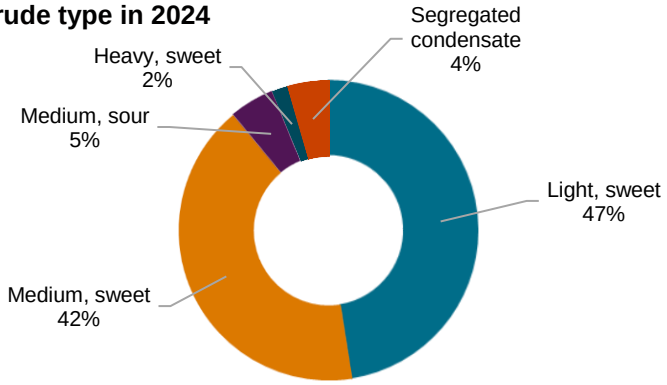
S&P Global
Commodity Insights

African crude exports by quality and regional destination

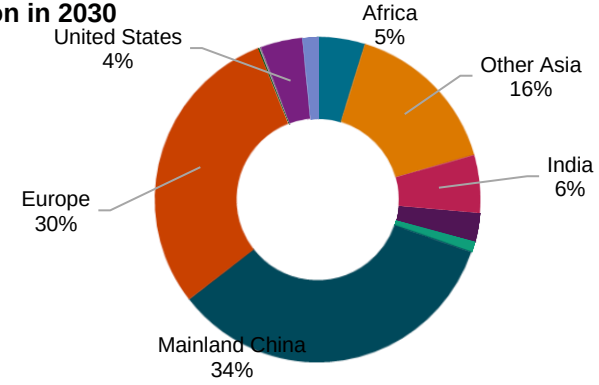
CIS exports by region in 2024



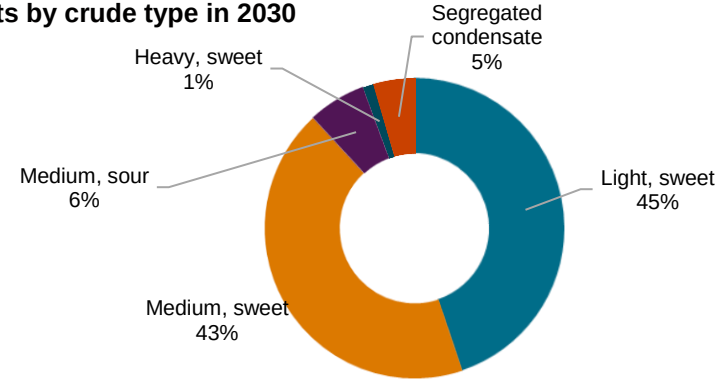
Africa exports by crude type in 2024



Africa exports by region in 2030



Africa exports by crude type in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

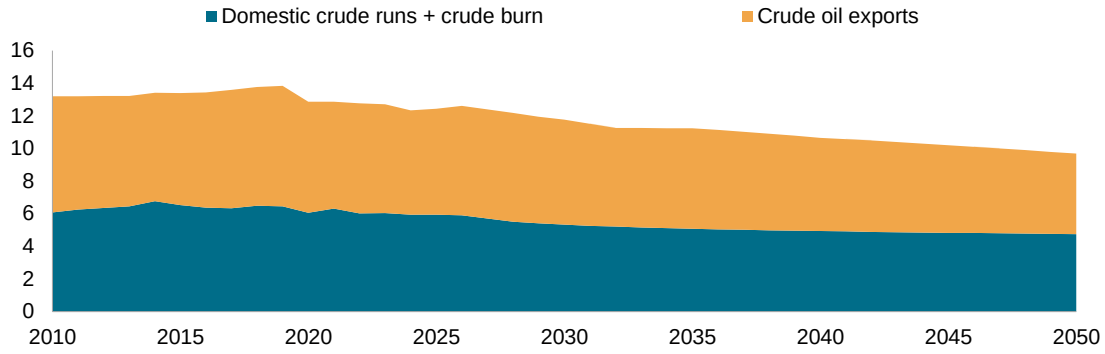
CIS exports reshuffle on sanctions: Russian flows are redirected to India and other Asian countries

- Limited investment is expected to significantly impact oil production in Russia, the region's largest producer, over the next decade. Crude output is expected to decline by 1.6 million b/d, falling from 9.0 million b/d in 2025 to 7.4 million b/d by 2035. This decline reflects the challenges Russia faces in maintaining production levels without access to capital.
- Domestic Russian refining – which accounts for ~80% of crude demand in the region – is expected to decline over the coming decades, as export-oriented refineries remain vulnerable to closures due to their relatively simple configuration and weak margin environment, with regional runs now expected to fall by 1.2 million b/d to 5.2 million b/d.

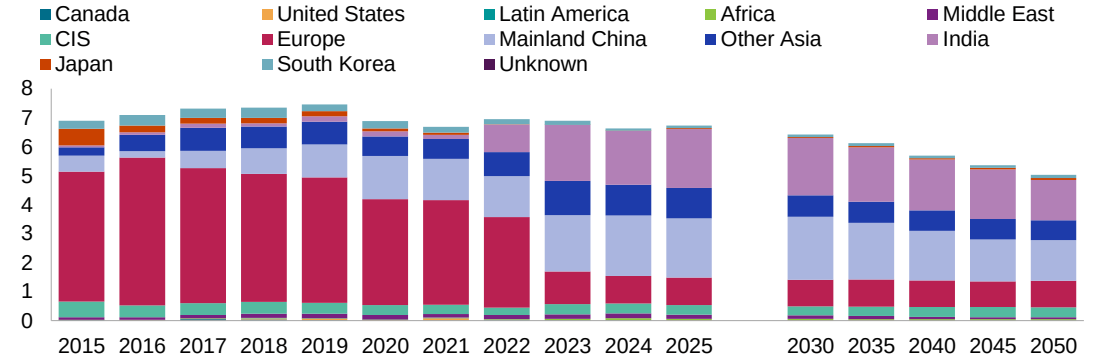
– Russian trade flows have been rewired. Europe's role as a key importer of Russian crude has been sharply reduced due to sanctions, with only non-OECD (Turkey in particular) Europe able to receive seaborne imports.

– Russian exports have mainly been redirected to India and Other Asian countries. Europe will still import some Russian oil by pipeline as a lifeline for those inland refineries with few other supply alternatives.

CIS domestic crude oil disposition (million b/d)



CIS crude and condensate exports (million b/d)

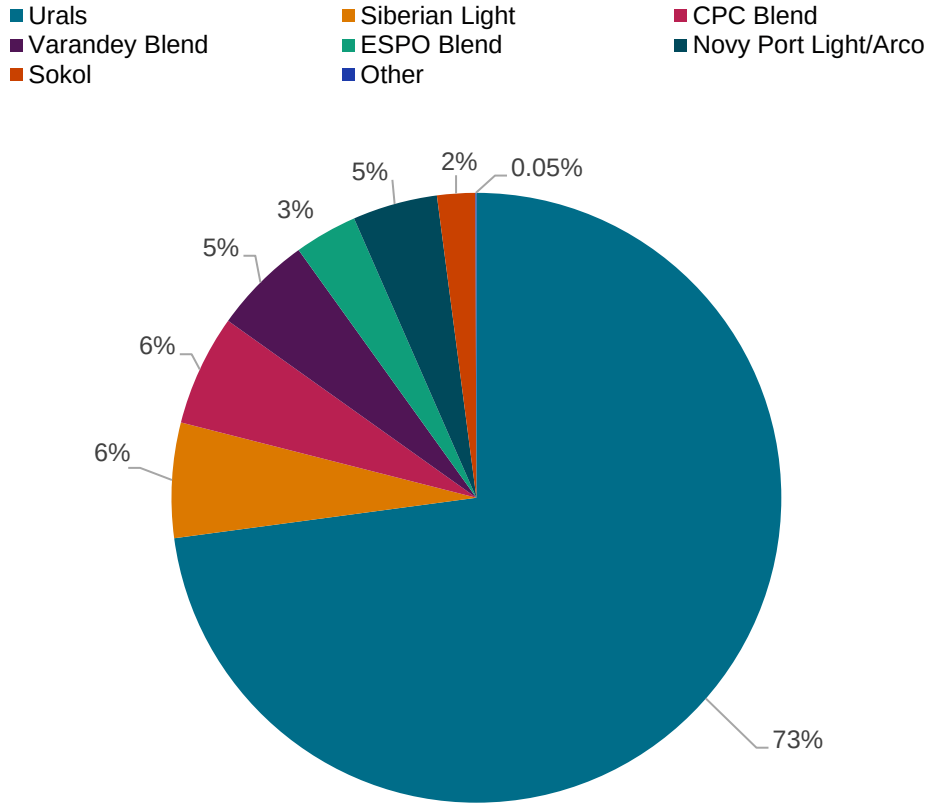


Data compiled: May 2025.
Source: S&P Global Commodity Insights.

S&P Global
Commodity Insights

Russia mostly exports Urals Blend to India and Turkey and ESPO Blend to China (mainland); the exposure of different Russian crude grades to sanctions varies widely

Distribution of Russia's oil exports to India in 2024 by crude

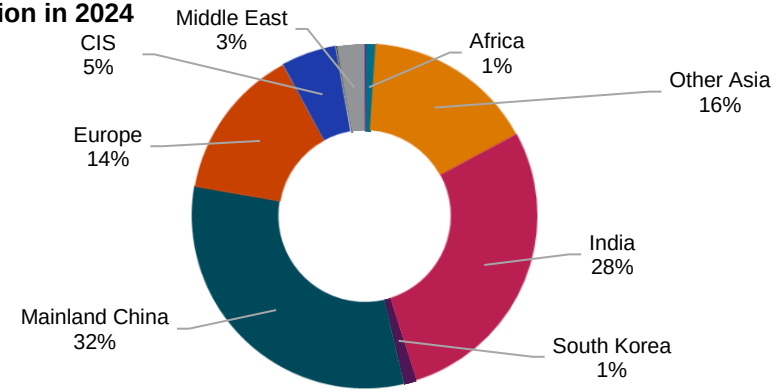


- India and Turkey are the chief buyers of Russia's Urals Blend, Russia's primary crude export stream — reflecting the closer proximity of the Urals outlets (i.e., the Russian Baltic and Black sea ports) to Indian and Turkish refineries compared with most of the other remaining markets for Russian oil.
  - Most of the Urals trade appears to remain outside the scope of direct Western sanctions; e.g., only about 19% of the tankers carrying Urals in 2024 were under sanctions (at last report).
- India and Turkey were also both key destinations for Russia's Siberian Light and CPC Blend exports in 2024, while India imported a variety of other crude streams from Russia last year, including Arctic and Sakhalin grades and some ESPO Blend.
- China (mainland)'s 2024 purchases of Russian crude were highly concentrated in the ESPO Blend grade (accounting for over half of China (mainland)'s seaborne purchases of Russian crude last year), while China (mainland) also imported significant volumes of Russia's Sakhalin crude grades and some Urals Blend.
  - Over 60% of the tankers carrying ESPO Blend in 2024 are currently targeted by Western sanctions, but China (mainland) also sources a major portion of its oil from Russia (nearly 40% of the total) via pipelines (ESPO, KCP) that are outside the reach of shipping-related sanctions.

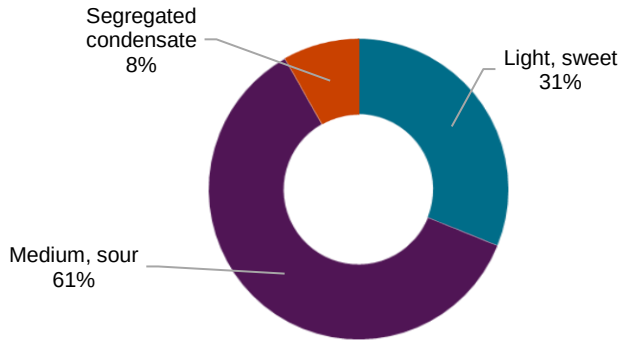
Data compiled April 14, 2025.
For a more detailed outlook see Russian oil balance dynamics in 2024 and outlook to 2030
Varandey Blend and Novy Port Light/Arco are crude grades originating from Arctic Russian oil fields; Sokol is the Sakhalin-1 crude grade.
Source: S&P Global Commodity Insights.

CIS crude exports by quality and regional destination

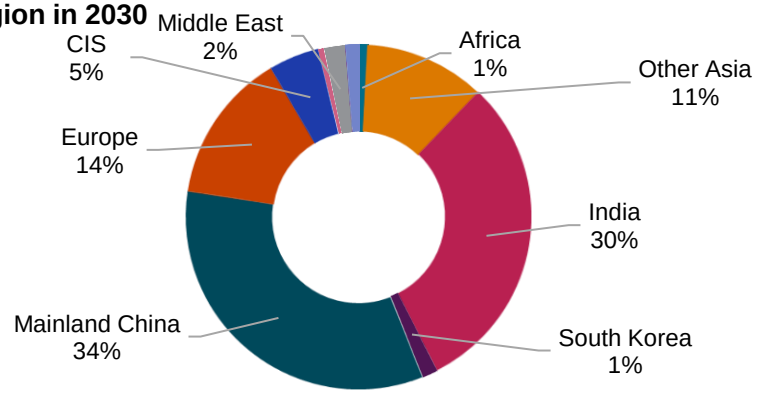
CIS exports by region in 2024



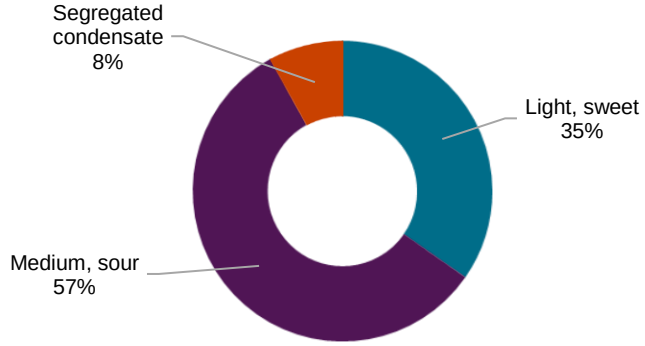
CIS exports by crude type in 2024



CIS exports by region in 2030



CIS exports by crude type in 2030



Data compiled: May 2025.
Source: S&P Global Commodity Insights.

Appendix

Geographic definitions

Africa: Africa is all of the African continent, including North Africa.

Asia: Asia is east of Iran, excluding Eurasia and including Pacific states.

- **OECD Asia:** Australia, Japan, New Zealand, and South Korea
- **Mainland China**
- **Non-OECD Asia/Pacific:** Asia excluding the OECD Asia/Pacific countries and mainland China

CIS: CIS is the former Soviet Union except Estonia, Latvia, and Lithuania.

Europe: Europe is OECD and non-OECD Europe and includes Turkey, Cyprus, Estonia, Latvia, Lithuania, and Malta.

Latin America: Latin America is Central and South America, including Mexico, and Puerto Rico and the US Virgin Islands.

Middle East: Middle East is Asia west of Afghanistan, excluding Eurasia and Turkey.

North America: North America is Canada and the United States, excluding Puerto Rico and the US Virgin Islands.

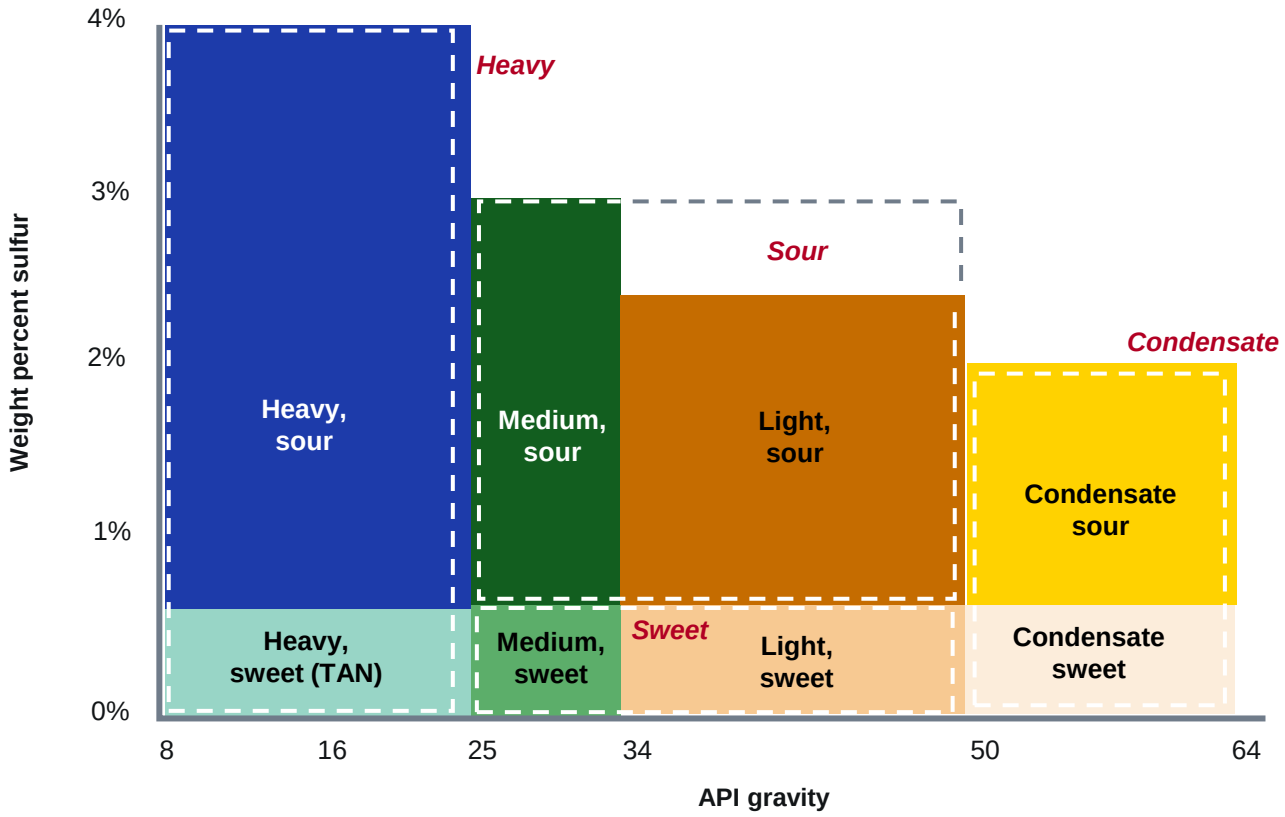
Data compiled May 1, 2023.
Source: S&P Global Commodity Insights.

Development definitions

- **Base.** This classification of development is defined as oil fields that are producing today. This classification of development represents the entire volume of current oil supply. Each producing field follows some form of production profile. There are typically three phases to a production profile. These include a buildup phase, where new wells are staged into production; a plateau phase, where new wells are brought onstream to offset declining, older wells; and a decline phase, where either reservoir pressure declines, or water cut rates increase. This profile is determined by both belowground and aboveground factors. Belowground factors include the geological characteristics of the reservoir (porosity, permeability, etc.), reservoir management, and field maintenance practices. Examples of aboveground factors include national policies regarding production quotas, geopolitical conflicts or lack of sufficient infrastructure to transport the crude oil to market. Production profiles of oil fields in the same region typically have similar trends owing to common geological characteristics and development techniques. As an example, deepwater offshore fields tend to reach plateau phases quickly and then experience steeper decline phases than typical onshore developments, primarily owing to producing companies requiring quicker recovery rates to offset the higher costs associated with offshore developments. Therefore, fields with more mature production profiles can indicate expected production profiles from fields in the same area that have yet to exhibit multiple phases, assuming comparable resource management techniques and external factors. The application of tertiary recovery methods or EOR and reserves growth also has an impact on the production profile of an existing development.
- **Sanctioned.** This classification of development is defined as an appraised project that has been sanctioned for initiating new production from a given field. At the time of analysis, these developments have yet to produce any commercial volumes but are anywhere from a few months to as many as 10 years away from first oil.
- **Unsanctioned.** This classification of development is defined as an appraised project that has not yet met the final investment decision (FID) hurdle. This result creates a project queue that will be a slow response system to increasing oil prices.
- **Yet to find (YTF).** This classification of development represents either resources that are known to exist, but no projects to turn these resources into production are being actively pursued, or resources that have yet to be discovered. The amount of production determined from future developments is based on projected growth for replacement of reserves. This situation suggests that the petroleum industry will continue its track record of expanding reserves and increasing production to overcome the decline of mature fields as well as keep pace with incremental demand. It is important to note that reserve growth is not limited by finding and developing currently undiscovered oil fields, but by a number of other factors.

Crude quality definitions

S&P Global Commodity Insights oil markets and downstream crude oil grade map (general)



- Light, sweet (LSW) crude oils are defined as having APIs above 34-50 API and sulfur content less than 0.6%. Light, sour (LSR) crude oils are defined as those above 34-50 API and with sulfur content greater than 0.6%. Heavy, sour (HSR) crude are those below 25 API and have sulfur content greater than 0.6%. Medium crudes fall somewhere in between the extremes of the API range reserved for light and heavy crudes (API between 25 and 34) and can be either sweet (sulfur content lower than 0.6% by weight) or sour. The term "condensate" is produced from gas fields, typically with a gravity of 50 API or higher.
- That being said, there are not strict definitions on crude quality and we do use some latitude when characterizing certain crude oils that are near the limits for certain classifications, because it is useful to group crude oils together that are generally competitive and interchangeable for analytical purposes.

Data compiled Jan. 1, 2025.
Source: S&P Global Commodity Insights.

Links to Annual Strategic Workbook research and resources

Access to individual reports depends on client subscriptions.

Region	Crude Oil Markets	Refining and Marketing	NGLs
Global	Platts Connect S&P Connect	Platts Connect S&P Connect	Platts Connect S&P Connect
North America	Platts Connect S&P Connect	Platts Connect S&P Connect	Platts Connect S&P Connect
Latin America	Platts Connect S&P Connect	Platts Connect S&P Connect	Platts Connect S&P Connect
Europe, Eurasia and Africa	Platts Connect S&P Connect	Platts Connect S&P Connect	Platts Connect S&P Connect
Asia-Pacific and Middle East	Platts Connect S&P Connect	Platts Connect S&P Connect	Platts Connect (MDE) Platts Connect (Asia) S&P Connect

Selected recent reports, event materials and datasets. Access to individual reports depends on client subscriptions.

Links to Crude Oil Markets research and resources

- Insight Access to new acreage: The key to shaping the future of Gulf of Mexico crude production (May 2025)
- Insight Oil Market Briefing: Supply unleashed — Implications of accelerated OPEC+ production increases (May 2025)
- Insight Orderly retreat: OPEC+ to raise oil supply some more despite falling prices, indicating it is continuing to back away from policy of price defense (May 2025)
- Insight US Strategic Petroleum Reserve refill: How long will it take? (May 2025)
- Insight Tariff turbulence: How trade tensions reshape China's economic growth and oil demand dynamics (April 2025)
- Insight Analogues and anomalies: What can we learn from prior periods of declining world oil demand? (April 2025)
- Insight Margin call: In search of the 'marginal barrel' (April 2025)
- Insight Context matters: What are oil prices telling us? (April 2025)
- Insight Coming apart: The rise of economic nationalism has consequences — $50/b oil just might be one of them (April 2025)
- Insight Onward and upward: OPEC+ to increase oil output in May, with much of the increase coming from the Gulf-3 — Saudi Arabia, UAE and Kuwait (April 2025)
- Insight Oil Market Briefing: Higher tariffs and lower oil demand growth (April 2025)
- Insight Upstream cost: The legacy of the great deflation (July 2024)
- Scheduled Update Global Crude Oil Markets Short-Term Outlook — Slides and data, June 2025 (May 2025)
- Scheduled Update North America Crude Oil Markets Short-Term Outlook — June 2025: As OPEC+ unleashes supply, will US shale play the swing producer again? (May 2025)
- Scheduled Update Asia and Middle East Crude Oil Markets Short-Term Outlook, June 2025: Global uncertainty drives crude source diversification (May 2025)
- Scheduled Update Latin America Crude Oil Markets Short-Term Outlook, June 2025: Latin sweet supply resilient amid expected OPEC+ growth (May 2025)
- Scheduled Update Europe, Eurasia and Africa Crude Oil Markets Short-Term Outlook, June 2025: All eyes on OPEC+ decision, but oversupply remains inevitable (May 2025)
- Scheduled Update China Crude Oil Markets Short-Term Outlook, June 2025: Runs to rebound with conclusion of heavy maintenance season (May 2025)
- Methodology Global and Regional Crude Oil and Refined Product Markets Methodology (Dec. 9, 2024)
- Methodology Integration of heritage Platts Analytics and heritage IHS Markit short-term oil supply: The new outlook explained (Aug. 18, 2023)
- Methodology Integration of heritage Platts Analytics and heritage IHS Markit short-term oil demand: The new outlook explained (July 25, 2023)

Appendix 2: Price forecast approaches and philosophy are different for short, medium and long term

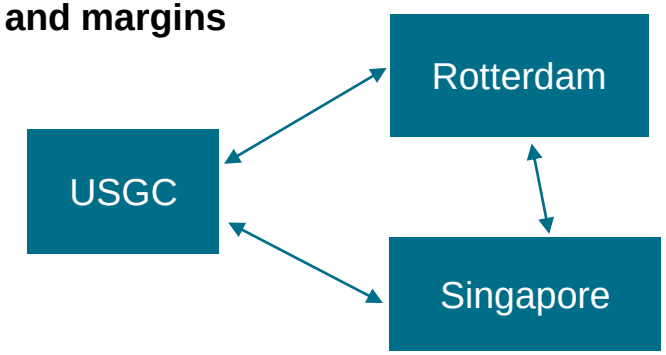
- Forecast horizons:
  - **Short term** (24 months)
    - Evaluation of current market versus balanced market equilibrium level — how “long/short” is the current market?
    - Accounts for market momentum, inventory levels, trade dynamics, capacity outages, etc.
    - Seeks to reflect industry response from current condition forward over a period of months based on available capacity, feedstocks, ability to arbitrage and other constraints
  - **Medium term** (~5 to 10 years)
    - Balances starting from short-term balance and incorporating investment and capacity changes
    - Addresses cyclic dynamics of market — reversion to the mean as defined by long-term equilibrium
  - **Long term** (currently to 2050)
    - Based on long-term demand trends, projections of costs and technology developments
    - Equilibrium pricing set by incremental and reinvestment economics for selected benchmarks assets (e.g., margin integrated naphtha cracker in Asia or return on coking upgrade project in Asian refinery)
    - Capacity additions modeled to meet demand growth — seeking resultant price that allows profitable supply without overbuild

Source: S&P Global Commodity Insights.

Refining and price forecast methodology

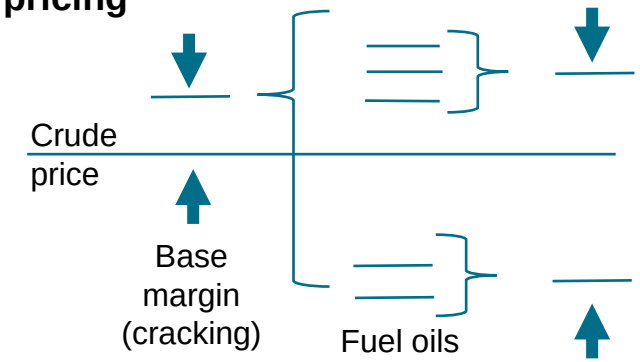
Refining utilization and margins

Margin input in each major region. Arbitrage established to support trade flows



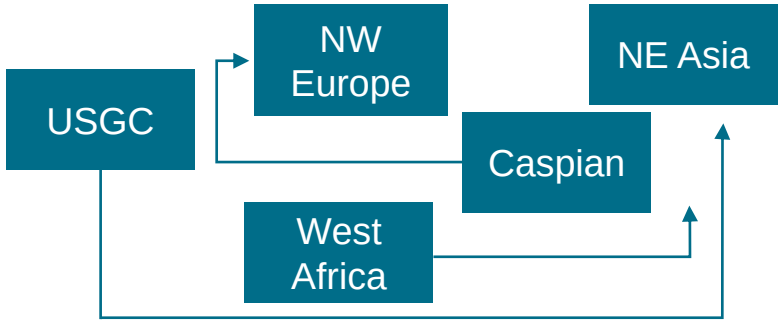
Refining margins pricing

Base margins set at stay-in-business levels. Conversion projects and new-build refineries provided investment returns in only certain markets

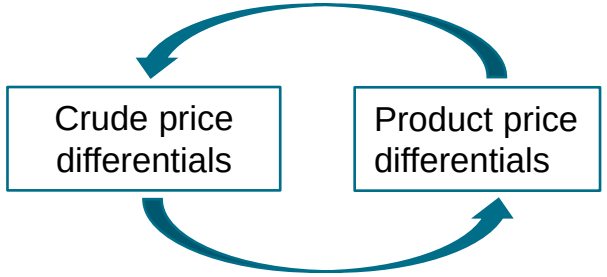


Crude pricing: Trade and quality

Crude FOB price relationships determined through marginal-refining economics and transportation



Crude-product pricing



Crude and product price relationships interrelated through refining economics

Relationship based in each regional market

Source: S&P Global Commodity Insights.

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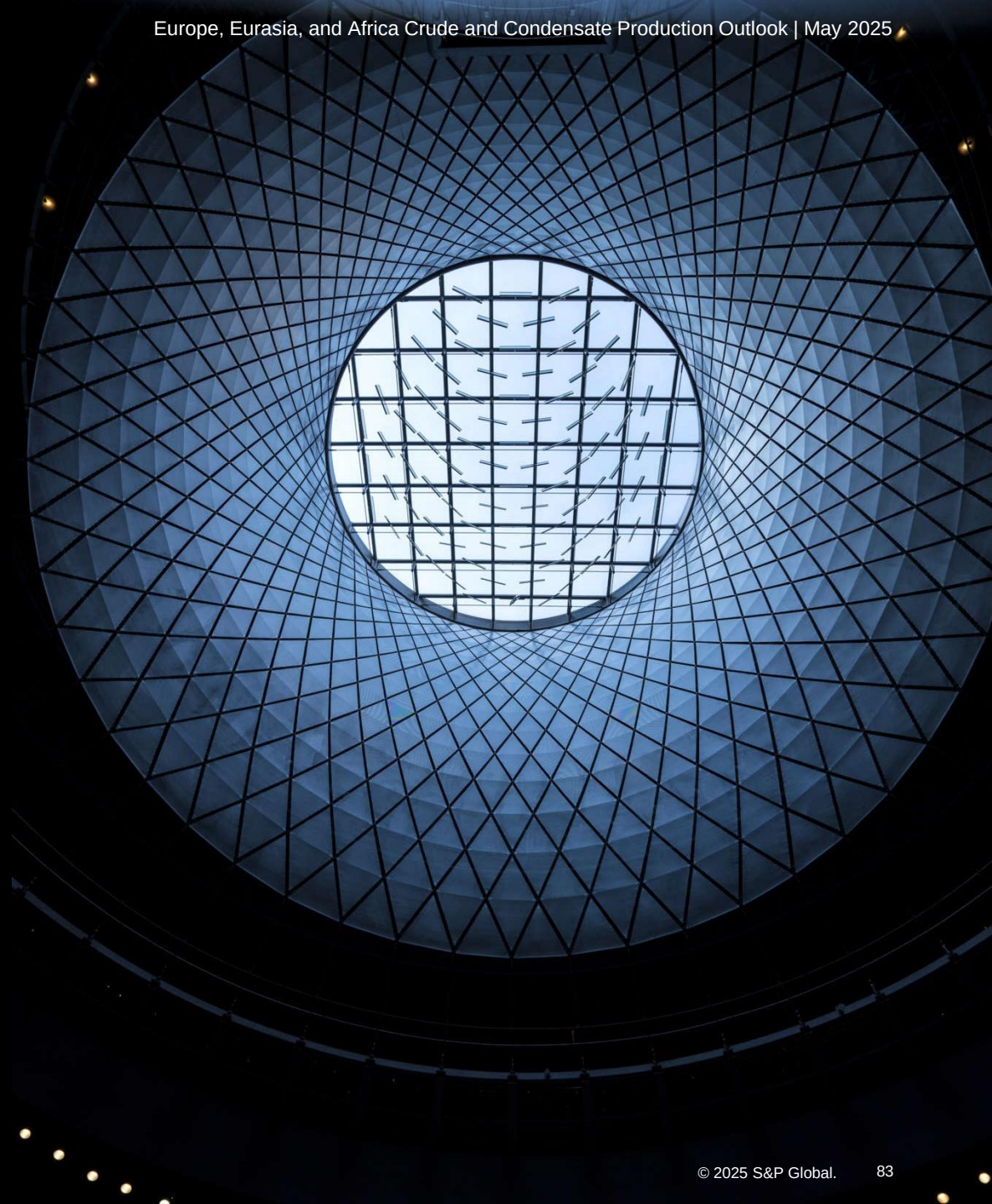

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