RystadEnergy

Whitepaper

Bridging the looming production gap

Rystad Energy's analysis of the role of offshore in a changing global market

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OFFSHORE TECHNOLOGY CONFERENCE

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Executive summary

The global energy market is going through a period of transition, and the events of 2026 have brought energy security back to the forefront. On the surface, the market still looks well supplied in the near term. But the ongoing escalation in the Middle East, along with disruptions to key maritime routes, has highlighted how fragile that balance really is.

Global markets are seeing a disconnect: short-term supply looks comfortable, but the system is more exposed than it appears. Offshore oil production is already in managed decline at around 6% per year, so the industry needs to add roughly 1.7 million barrels per day (bpd) of new capacity annually just to stand still. Given that deepwater projects take five to seven years to develop, today's investment is not creating oversupply – it is simply avoiding a much sharper production drop in the early 2030s.

In response, capital is shifting toward what could be described as more 'advantaged' resources – projects that combine lower breakeven costs with relatively lower carbon intensity. Under a base case outlook, the scale of what is needed remains substantial: around 540 billion barrels of liquids must still be developed by 2050, alongside a widening gap in gas supply.

At the same time, there are early signs that capital allocation may be heading toward more stable, competitive regions, but it is still too early to draw firm conclusions. Recent developments have highlighted risks in some geographies that could influence future investment decisions. Even so, whether this translates into a sustained reallocation of capital remains to be seen. Regions such as Brazil, Guyana and the US Gulf of America are well positioned to attract increased interest given their resource quality and market access, but the pace and scale of any shift will ultimately depend on how geopolitical risks evolve and how investors respond over time.

There is a growing gap in visibility beyond the current wave of project approvals expected around 2027-2028. Offshore investment is set to reach around $124 billion in 2026, but maintaining long-term supply stability will require a much higher and more sustained level of capital. Bridging that gap will depend not only on continued allocation, but also on expanding into new frontier areas and accelerating the deployment of technologies such as high-pressure systems, subsea processing and electrification.

Ultimately, the current investment cycle is less about driving growth and more about keeping pace with the expected decline. The decisions made over the next few years will play a critical role in determining whether the global energy system remains stable or becomes increasingly constrained in the decades ahead.

The 2026 shift: From surplus to supply shock

The global liquids market has shifted sharply in 2026. What began as a projected surplus of around 3 million bpd has quickly turned into a supply shock driven by geopolitical disruption. The escalation in the Middle East and the effective blockade of the Strait of Hormuz have disrupted physical flows and reshaped market dynamics. What was previously seen as underlying oversupply has been overtaken by a clear 'fragility premium', as access to barrels, not just their availability, has become the defining issue.

Price dynamics and the market shock

This disruption has fed directly into prices. The 2026 Brent outlook has been revised upward from around $60 per barrel to an average of $87 per barrel. While prices are still expected to ease toward roughly $72 per barrel in 2027, the current backwardation reflects a strong near-term pull for deliverable barrels, as flows from the Middle East remain constrained.

Temporary shortage, not a lack of supply

Between March and May 2026, the market is expected to face an average deficit of about 2.4 million bpd. This is less a question of global capacity and more a result of physical bottlenecks.

Large volumes from Saudi Arabia, the UAE, and Kuwait are effectively stranded behind the chokepoint, leading to temporary production shut-ins as storage fills. Current estimates suggest that as much as 10 million bpd of supply west of Hormuz is impacted, creating a disruption that cannot be meaningfully offset in the near term.

Supply growth from outside OPEC+, particularly in the US, Brazil and Guyana, is helping to cushion the shock. Still, even under optimistic assumptions, this additional supply can only replace a fraction of the disrupted volumes, likely no more than 20-25%. As a result, the market is facing a significant and immediate supply shortfall.

What the 2026 shock really tells us

This episode highlights an important dynamic in the market. The near-term deficit does not necessarily contradict the broader outlook of ample supply, but it does interrupt how that supply reaches the market.

If the current disruption proves temporary and flows normalize within the next year, recent project sanctioning, particularly in more stable regions, will continue to play its intended role in maintaining longer-term balance. In that context, these investments are not creating excess supply but helping ensure that future demand can be met.

At the same time, the shock is already influencing investment decisions. Heightened geopolitical risk is likely to reinforce a shift in capital toward regions with more secure market access, suggesting that the impact of 2026 may extend beyond the immediate disruption.

The long-term reality: The 2050 production gap

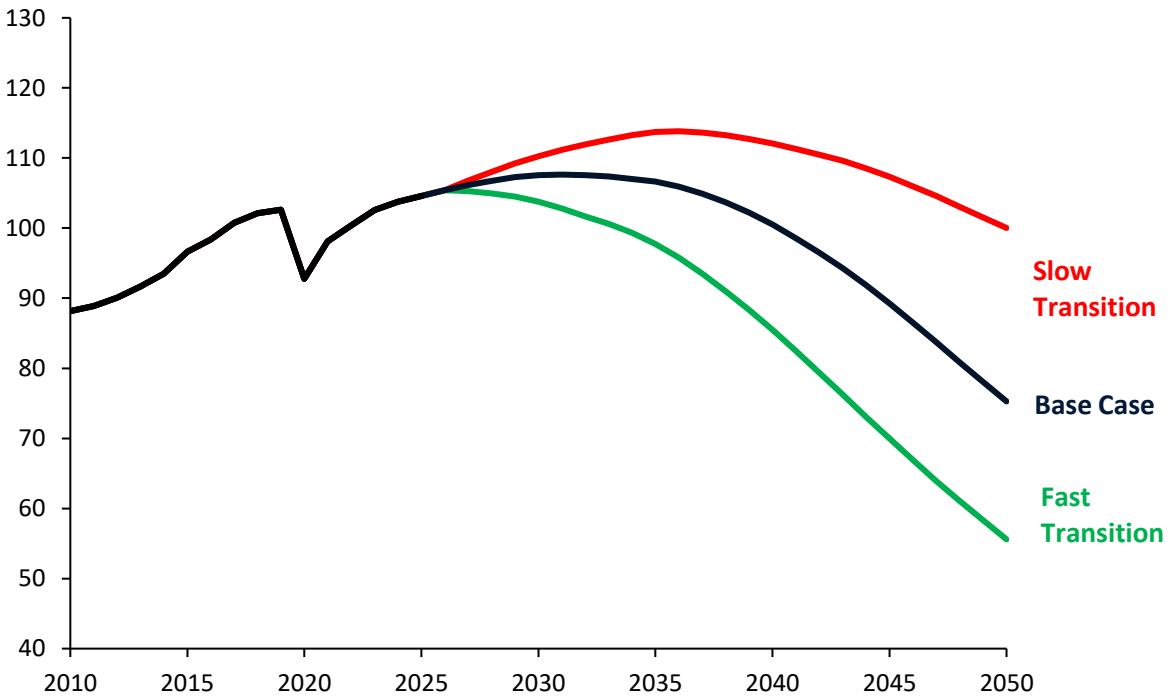
While the 2026 supply crisis and resulting price volatility are immediate disruptions, they must not obscure the long-term requirement. To meet 2050 targets, the industry must decouple its long-cycle strategies from the current 24-month horizon. The resulting production gap is a range of outcomes governed by a new era of energy fragility and the structural pace of the global energy transition.

Liquids demand scenarios: Three paths to 2050

We use a scenario-based framework to capture the range of possible demand[1] outcomes. While the paths diverge more clearly after 2030, they all point to the same underlying reality. A substantial amount of new production will be needed simply to offset declines in existing supply.

As indicated in **Figure 1**, a slower transition will result in a later peak, with demand remaining close to 100 million bpd by 2050. The base case presents a more balanced trajectory, with demand peaking in the early 2030s before gradually easing to around 75 million bpd. Even under a faster transition, in which decarbonization accelerates, demand remains at roughly 55 million bpd by mid-century.

Figure 1: Oil demand by scenario
Million barrels per day



Source: Rystad Energy OilMacroCube, March release

[1]**Slow Transition:** Upside vs. Base, assuming slower policy and tech adoption. Oil demand peaks at ~114 million bpd in 2036, then plateaus and declines to 100 million bpd by 2050.
Base case: Most likely pathway with stated/high-probability policies. Demand peaks at 108 million bpd in 2031, plateaus in the early mid-2030s, then falls to 75 million bpd by 2050.
Fast Transition: Rapid transition with aggressive policy and faster adoption. Demand peaks at 105 million bpd in 2026 and declines to 55 million bpd by 2050.

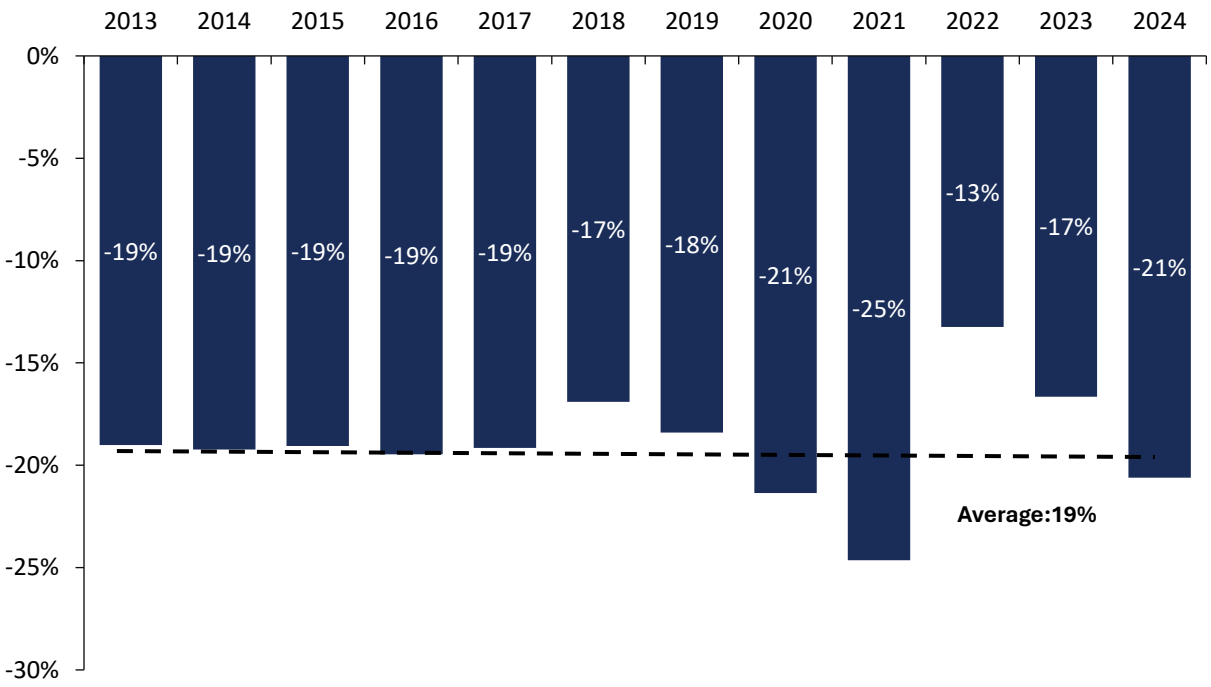
The long-term reality: The 2050 production gap

The decline cliff: The velocity of depletion

The decline cliff describes how quickly production would fall if new capital, especially for infill drilling and well interventions, were to cease.

On a global basis, the average natural decline rate[2] has held relatively steady at around 19% over the past decade. But that headline number hides a more uneven picture. Offshore assets tend to decline more gradually, providing a degree of stability, while onshore unconventional plays are characterized by much steeper, faster depletion.

Figure 2: Average annual natural decline rate (global oil)
Percentage



Source: Rystad Energy UCube, March release

[2]The natural decline rate describes how fast production would fall if no new investments were made in the field.

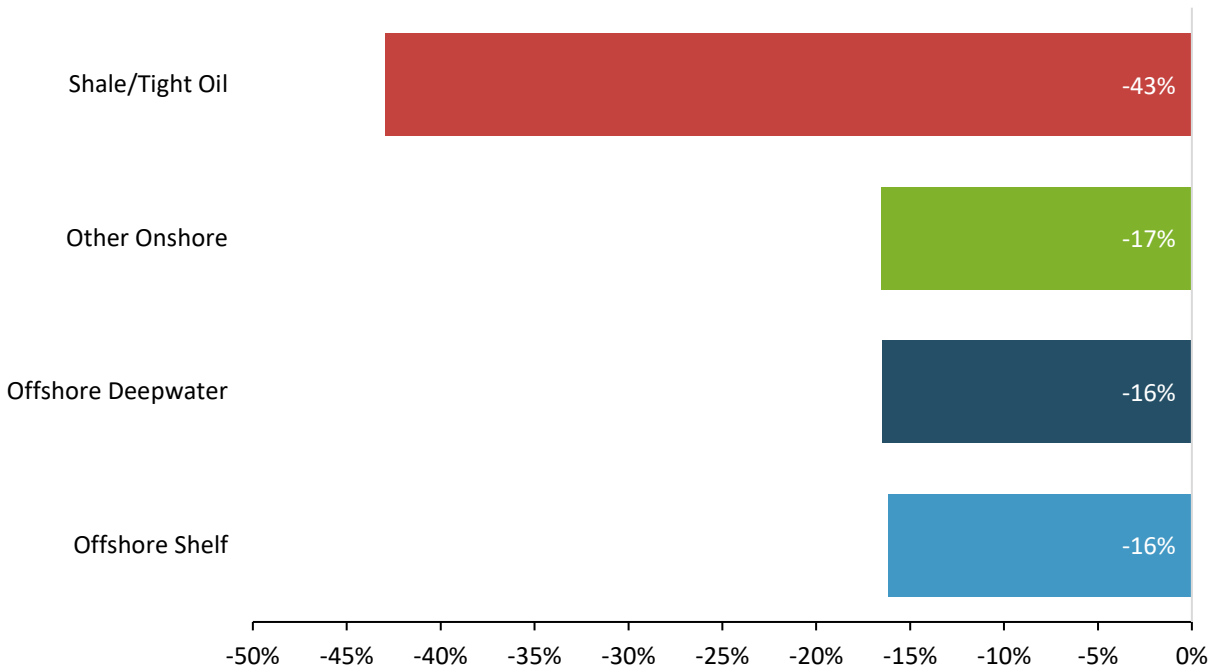
The long-term reality: The 2050 production gap

As shown in **Figure 2**, the global average remains broadly stable at around 19%, with only temporary disruptions during 2020–2022 driven by the pandemic, weak oil prices, and OPEC+ production cuts. However, breaking the data down by supply segment reveals a far more uneven dynamic. As illustrated in **Figure 3**, natural decline rates are most pronounced in unconventional plays, whereas offshore assets provide a comparatively more stable production base.

Shale and tight oil, for example, experience the steepest depletion, with decline rates averaging around 43%. This reflects the underlying reservoir characteristics and well designs, where production drops quickly and requires continuous drilling just to maintain output.

By contrast, offshore assets, both deepwater and shelf, show much more moderate rates, at around 16%. Conventional onshore assets fall into a similar range, averaging close to 17%, and behave more like offshore in terms of production stability.

Figure 3: Average annual natural decline rate by supply segment
Percentage



Source: Rystad Energy UCube, March release

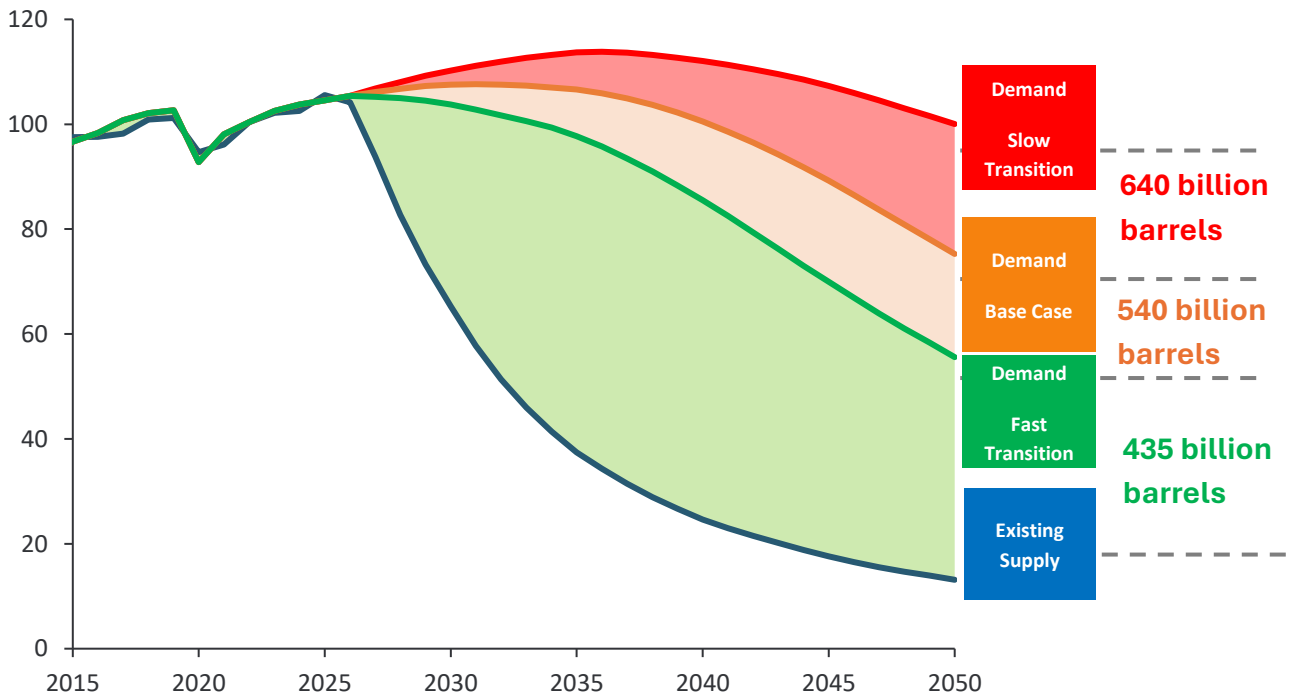
The long-term reality: The 2050 production gap

The discovery mandate

Global liquids supply reached around 105.4 million bpd in 2025, with conventional onshore production making up just over half of that, at roughly 55 million bpd. Shale and tight oil, which have driven much of the growth over the past decade, contributed about 18.7 million bpd, slightly more than offshore shelf at 17.6 million bpd. Deepwater, while smaller in absolute terms, accounts for around 10.5 million bpd and is set to play a larger role in future growth.

Looking ahead, even in the most aggressive transition scenarios, a substantial amount of oil will still be required to meet demand. This reinforces the continued importance of new discoveries and development, even as lower-carbon technologies gain momentum.

Figure 4: Liquids to be developed (2025-2050)
Million barrels per day



Source: Rystad Energy OilMarketCube, March release

The long-term reality: The 2050 production gap

The ‘gap’ represents the difference between current production declining over time and future demand. Closing that gap will require many new discoveries and developments.

The scale varies by scenario but remains substantial in all cases. In the Slow Transition, the industry would need around 640 billion barrels of new supply. Under the Base Case, that requirement falls to roughly 540 billion barrels, while even in a Fast Transition scenario, it remains at about 435 billion barrels.

In other words, even under the most aggressive transition pathways, the need for new supply remains considerable. This is not a sunset industry; on the contrary, the industry requires ongoing investment to ensure future production meets demand.

The capex requirement: Investing in the base case

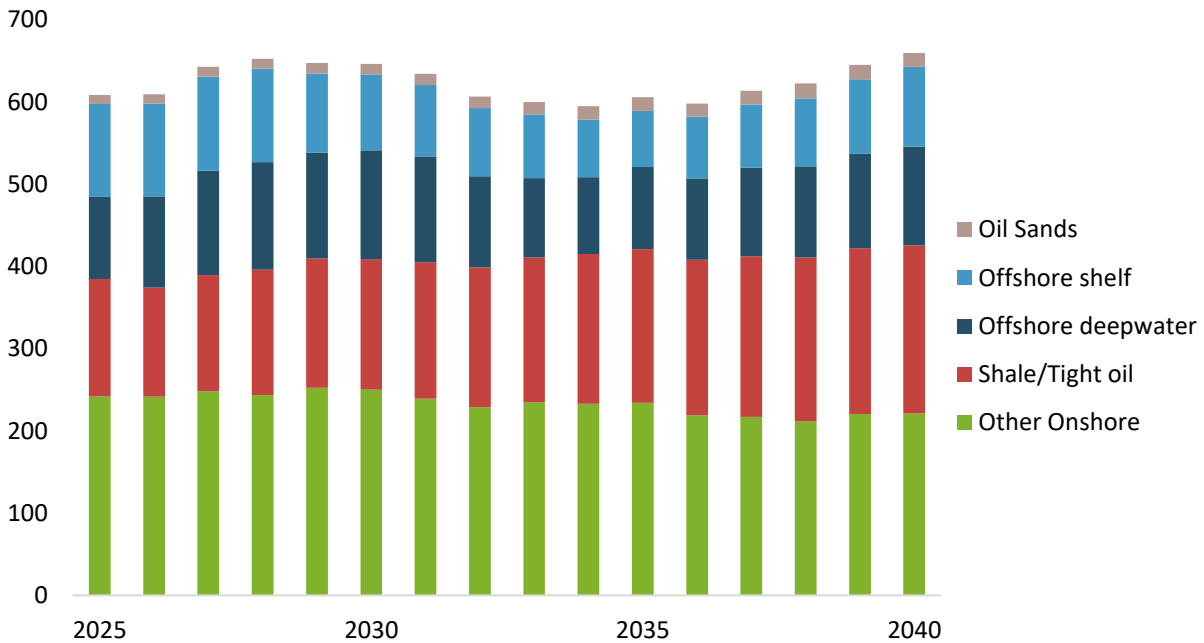
The current offshore spending trajectory reflects a clear shift toward prioritizing value over volume. While 2026 investment levels are expected to reach roughly 70% of the 2014 peak (around $880 billion), that gap is narrower than it appears. Much of the efficiency gains achieved over the past decade have already been realized, leaving less room to absorb further pressure.

The limits of efficiency gains

Since 2014, the industry has undergone a significant reset in capital efficiency, driven by cost deflation and productivity gains. Drilling activity across the board has dropped sharply, down roughly 50% from 2012’s level, yet production has remained steady, reflecting how much more output each dollar can now deliver. In effect, a $1.00 investment today generates about $1.40 in 2014 equivalent value.

That phase, however, appears to be reaching its limits. In offshore, a tighter rig market and high utilization are pushing up the cost of new capacity. At the same time, in US shale, the depletion of Tier 1 acreage is gradually shifting activity toward less productive areas, where more capital is needed just to maintain output.

Figure 5: Upstream capex by supply segment
Billion USD (Nominal)



Source: Rystad Energy UCube, March release

The long-term reality: The 2050 production gap

The projected $600-$640 billion in annual investment through the 2040s (see **Figure 5**) should not be seen as expansionary. It represents the level required to keep pace with a persistent annual decline of around 4%[3] in the existing production base.

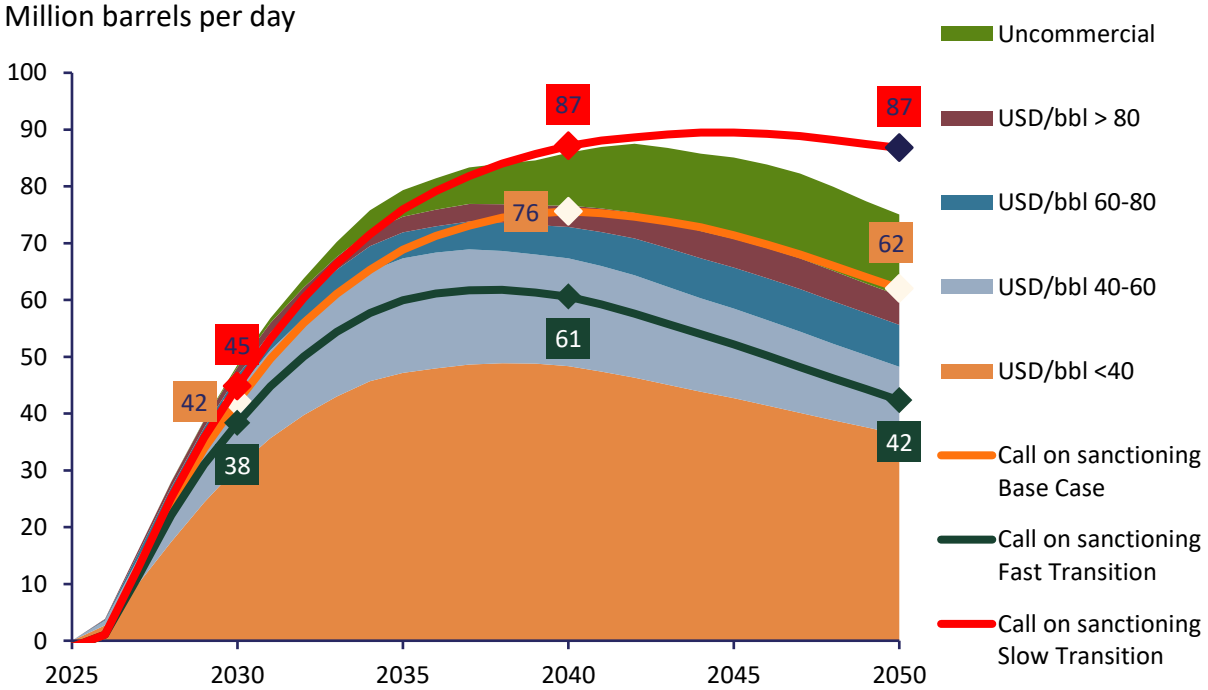
Falling below this range would leave the market increasingly exposed to price volatility. In today's environment, where supply security is more fragile, a large share of this spending is less about growth and more about maintaining stability.

At the same time, the direction of capital is beginning to evolve. As highlighted in the 2026 conflict analysis, heightened geopolitical risk is increasingly being reflected in how investors assess regional exposure, with growing attention on areas such as Guyana, Brazil, and the US Gulf of America, where projects offer competitive breakeven typically in the $30-$45 per boe range, and more stable operating conditions.

Sanctioning requirements and price sensitivity

Bridging the gap between current production and future demand will depend on a steady flow of new project approvals. In practical terms, this means moving a large share of discovered, pre-final investment decision (FID) resources into development.

Figure 6: To be developed liquid supply and call on sanctioning
Million barrels per day



Source: Rystad Energy UCube, March release

[3]Unlike the **natural decline rate** (Section 2.2), which measures the production loss from an asset assuming zero further intervention, the **field decline rate** reflects the "managed" decline. It accounts for the mitigating impact of ongoing capital reinvestment, such as infill drilling, well workovers, and enhanced recovery techniques, intended to slow the base depletion of a mature asset.

The long-term reality: The 2050 production gap

As illustrated in the figure above, the volume of oil that needs to be sanctioned varies by transition pathway, but the scale remains substantial in all cases. By 2040, the 'call on sanctioning' reaches around 76 million bpd in the Base Case, rising to roughly 87 million bpd under a slower transition. Even in a faster transition scenario, the industry would still need to sanction close to 61 million bpd to offset natural decline.

What stands out is where this supply is expected to come from. Across all scenarios, most of the required volume falls within the lower-cost segments of the curve, typically below $60 per barrel. This is where modern deepwater developments are increasingly positioned, reflecting years of cost and efficiency improvements.

In that sense, a large share of future supply is likely to be anchored in these more competitive barrels. The prevalence of sub-$60 per barrel resources across both the Fast Transition and much of the Base Case underscores why offshore projects are often seen as more resilient investments, particularly in a more carbon-constrained, cost-sensitive environment.

Offshore in the global supply system

Offshore production remains a central pillar of the global energy system. By 2025, it is expected to account for roughly 27% of global liquids supply (around 28 million bpd) and close to 29% of global gas supply, with total global gas production at around 4,116 billion cubic meters (Bcm). More importantly, its role is evolving. Offshore is no longer just a source of volume. It is increasingly acting as a stabilizing force in a market shaped by growing geopolitical uncertainty.

Today's surplus does not solve tomorrow's gap

At first glance, the coexistence of record project sanctioning and near-term supply surpluses appears contradictory. In reality, this reflects the long development timelines inherent to offshore. While the market may face short-term disruptions, such as the 2026 supply shock linked to Middle Eastern tensions, the industry is also working to offset future declines.

With an average field decline rate of around 6% across existing offshore production, roughly 1.7 million bpd of new resources need to be sanctioned each year just to maintain current output levels. Given the typical five- to seven-year lead times for deepwater projects, today's investment cycle is less about creating oversupply and more about preparing for the structural tightening expected in the early 2030s.

Capital moving to the Atlantic Margin

Capital is increasingly moving toward the Atlantic Margin, particularly the US Gulf of America, Brazil and Guyana. As tensions in the Middle East raise concerns around the reliability of key transit routes like the Strait of Hormuz, these regions offer a different value proposition: more secure, direct access to global markets.

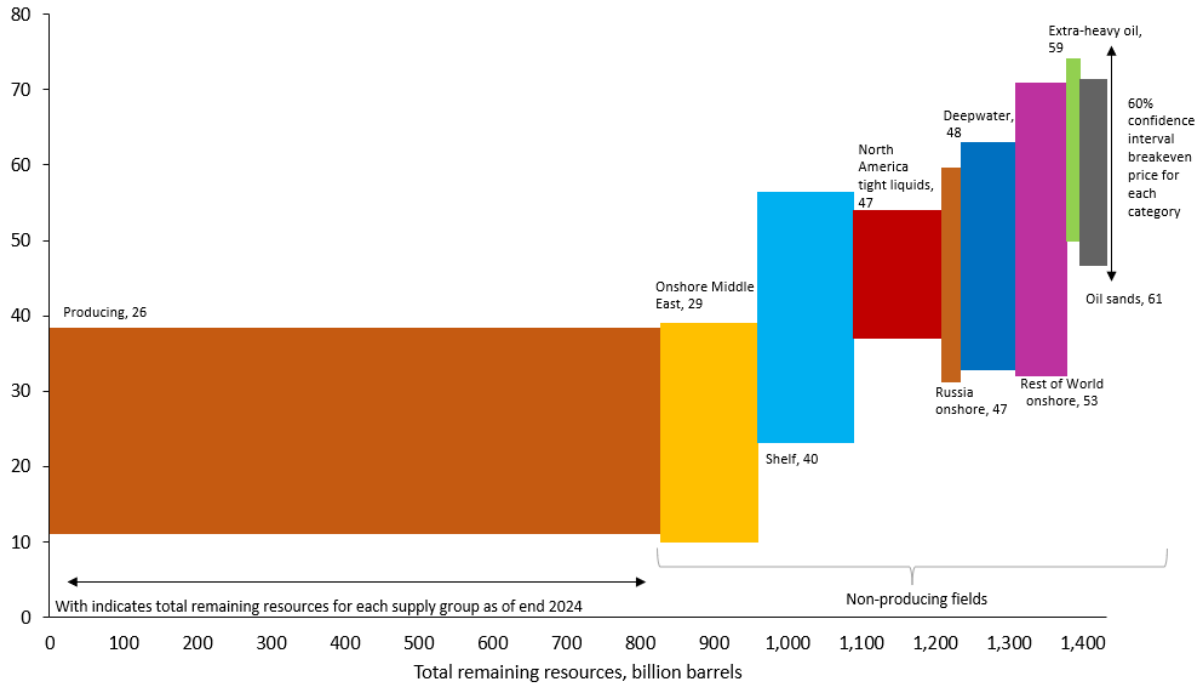
In this context, the Atlantic Margin is taking on a broader strategic role. It is no longer just a source of incremental growth, but a way for operators to reduce exposure to geopolitical chokepoints and build more resilient supply chains.

Where new supply sits on the cost curve

What's happening is not just an increase in supply, but a gradual reshaping of the global cost curve. New offshore developments are increasingly competitive, not only in cost but also in emissions, compared with many remaining onshore supply segments.

Offshore in the global supply system

Figure 7: Cost of supply curve for remaining resources
Brent breakdown price, USD per barrel*

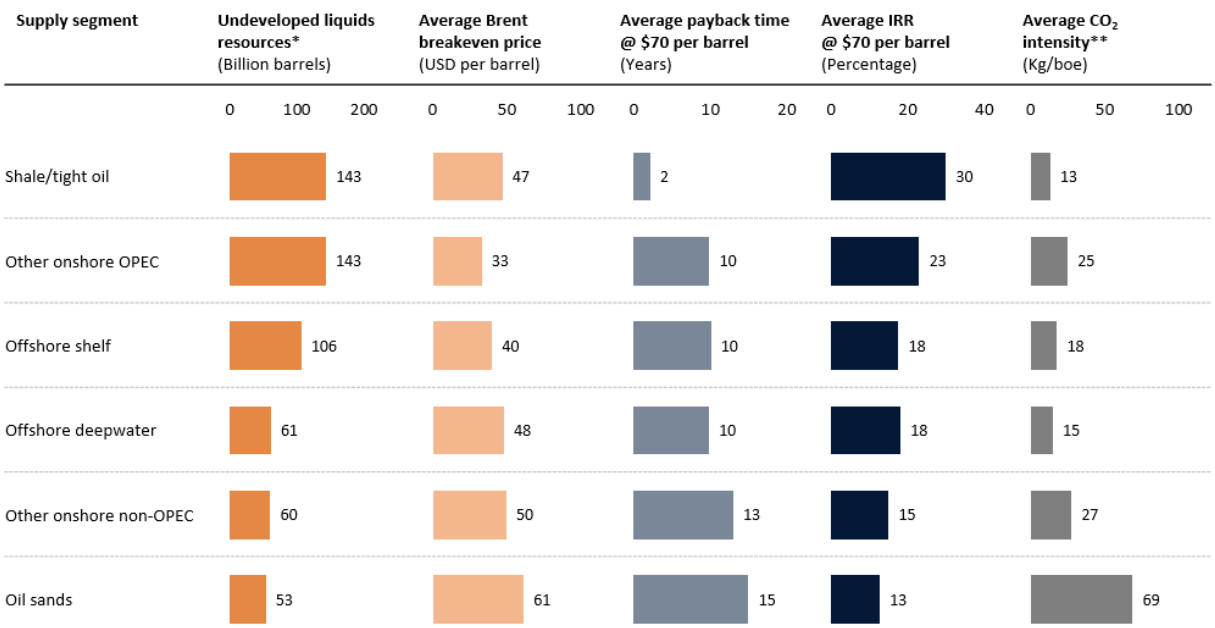


*Breakeven price is the real Brent oil price that gives a net present value of zero, given a real discount rate of 7.5%. Breakeven price only includes future costs. Boxes represent the average across all fields within each category. Resources are as of 2026.
Source: Rystad Energy UCube, March release

As shown in **Figure 7**, recently sanctioned offshore projects tend to sit on the left-hand side of the cost curve, alongside some of the most competitive sources of supply. This positioning is important, but it only tells part of the story. When viewed in the context of the broader resource base, it becomes clear that offshore is not just adding barrels. It is shifting the overall quality of supply, moving the industry toward more efficient and resilient sources over time.

Offshore in the global supply system

Figure 8: Benchmark of key sources of new oil supply



*Includes discovery lifecycle; **Average values for the years 2020 to 2024
Source: Rystad Energy UCube, March release

Modern offshore projects are increasingly judged not just on their internal rate of return (IRR), but on CO_2 intensity. As illustrated in **Figure 8**, offshore deepwater and shelf projects provide some of the 'cleanest' barrels in the global portfolio. Deepwater and shelf developments now sit on a more competitive part of the curve than higher-cost sources such as oil sands and extra-heavy oil. By focusing on these more advantaged barrels, the industry is gradually replacing higher-cost, higher-emission sources, in addition to boosting supply. While the projected $640 billion in annual investment will continue to be spread across a range of asset types, including onshore conventional and higher-cost segments, the direction of capital is increasingly shaped by these more competitive offshore opportunities.

Balancing liquids and gas in a changing market

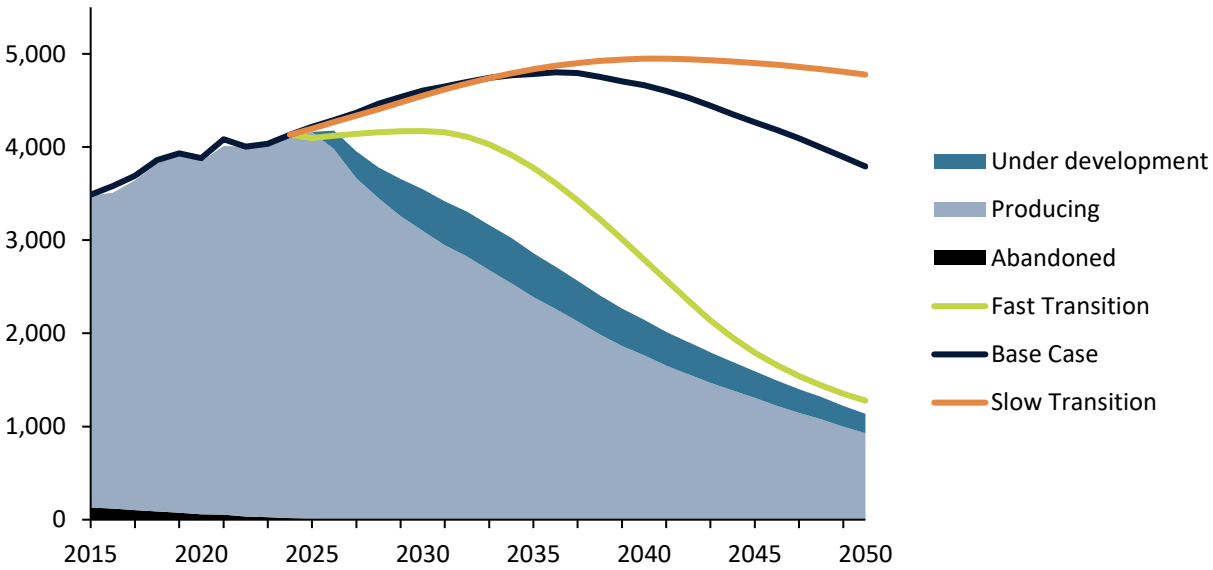
In the 2026-2030 cycle, the idea of an 'advantaged barrel' is broadening into a more integrated concept. Offshore is no longer just about delivering high-margin liquids. It is increasingly valued for its ability to pair those volumes with a reliable gas supply, which plays a growing role in energy security.

Offshore in the global supply system

As shown in **Figures 4 and 9**, the scale of the challenge is significant. Meeting Base Case demand requires around 540 billion barrels of new liquids supply by 2050, alongside an annual gap of roughly 2,700 Bcm. These are closely linked rather than separate targets, and they point to the need for a more balanced approach to exploration.

In practice, this means combining near-term, infrastructure-led developments that can be brought online quickly with longer cycle frontier exploration that unlocks greater resource potential. Together, these approaches enable operators to create more diversified portfolios, which are supported by offshore developments better equipped to handle both price volatility and changing demand across commodities.

Figure 9: Producing and under-development gas supply vs. demand by scenario
Billion cubic meters

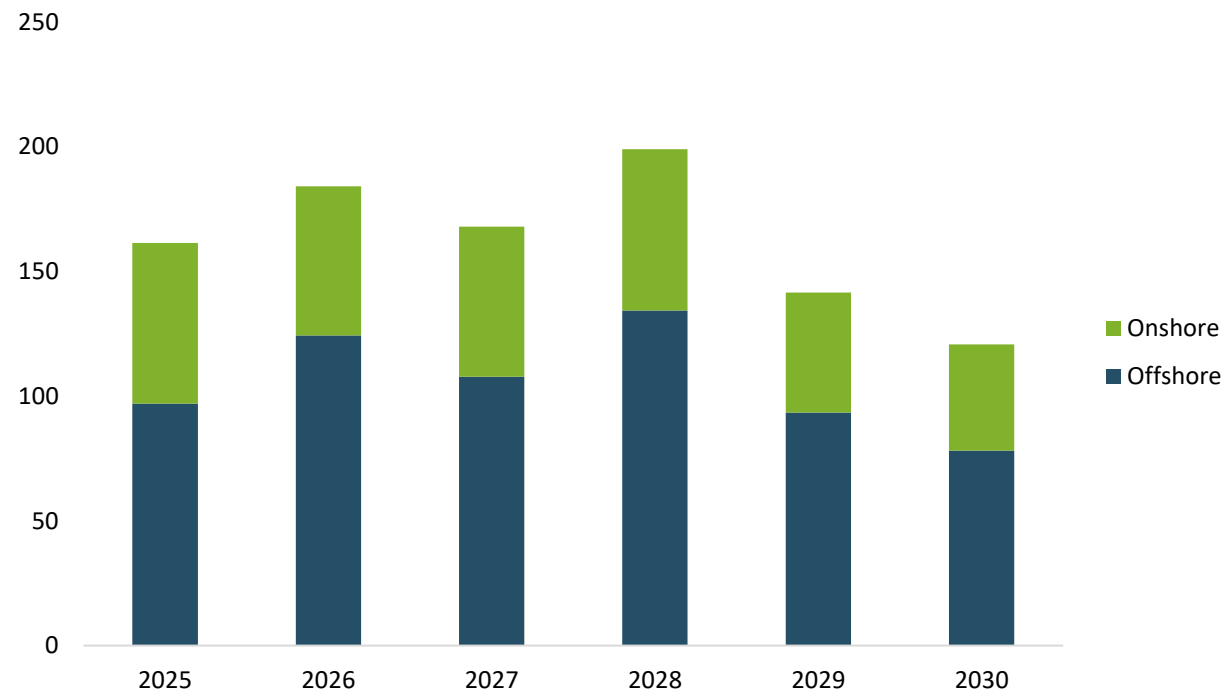


Source: Rystad Energy GasMarketCube, Rystad Energy research and analysis, March release

Offshore greenfield development activity and capital allocation

The upstream story heading into the late 2020s is shifting. The focus is no longer on maximizing volume but on allocating capital more selectively to barrels that are both cost-competitive and lower in carbon intensity. In that context, offshore is taking on a more central role in securing long-term supply.

Figure 10: Greenfield sanctioning by location (offshore vs. onshore, 2025-2030)
Billion USD



Source: Rystad Energy ServiceDemandCube Oil & Gas, March release

As shown in **Figure 10**, global greenfield investment is expected to reach around $184 billion in 2026, with offshore accounting for roughly $124 billion, or about 70% of total. This reinforces the idea that offshore is now driving new capital commitments, while onshore shale moves into a more mature, consolidation-driven phase.

Beyond 2028, activity is expected to ease, but the underlying supply challenge does not. Meeting that expected 2050 demand will require a shift away from today's more cautious investment approach toward a sustained annual spend closer to $640 billion. Without a meaningful push into frontier developments, the expected peak around 2028 risks being short-lived, rather than the start of a more durable growth cycle.

Offshore greenfield development activity and capital allocation

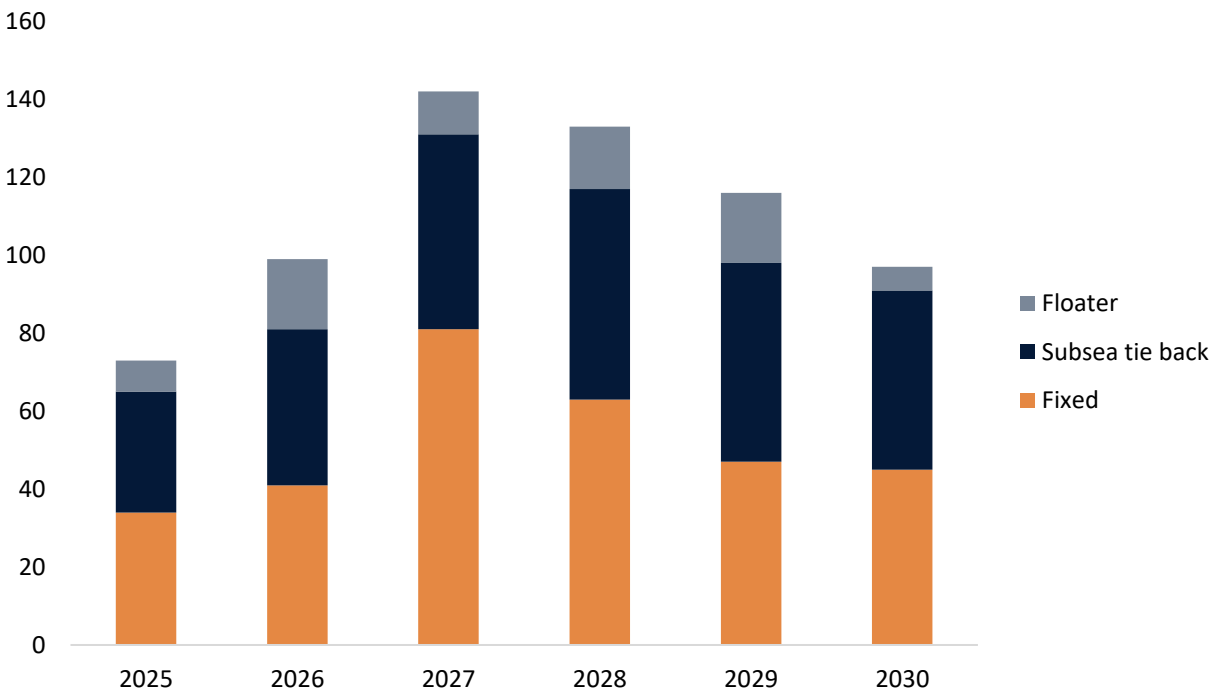
How offshore development is evolving

Offshore development is undergoing a clear shift as the industry adjusts to a tightening supply outlook through 2050. Rather than relying on a single development model, operators are leaning on a mix of approaches to balance cost, speed and resource access.

Fixed platforms continue to play a central role, particularly in the Middle East and shallow-water Asia, where they support large-scale, high-volume gas developments. At the same time, subsea tiebacks are gaining momentum. By building around existing hubs, they offer shorter lead times and stronger project economics, making them one of the most consistent sources of activity growth through the end of the decade.

Further offshore, floating units such as FPU, FPSO, and FLNG remain critical for unlocking deepwater resources. They are especially relevant in areas where pipeline infrastructure is limited or absent, such as Namibia or parts of Brazil. In more established basins, they also continue to support developments tied to existing networks, providing flexibility across a wide range of project types.

Figure 11: Offshore greenfield sanctioning activity by development type (2025-2030)
Number of projects



Source: Rystad Energy ServiceDemandCube Oil & Gas, March release

Offshore greenfield development activity and capital allocation

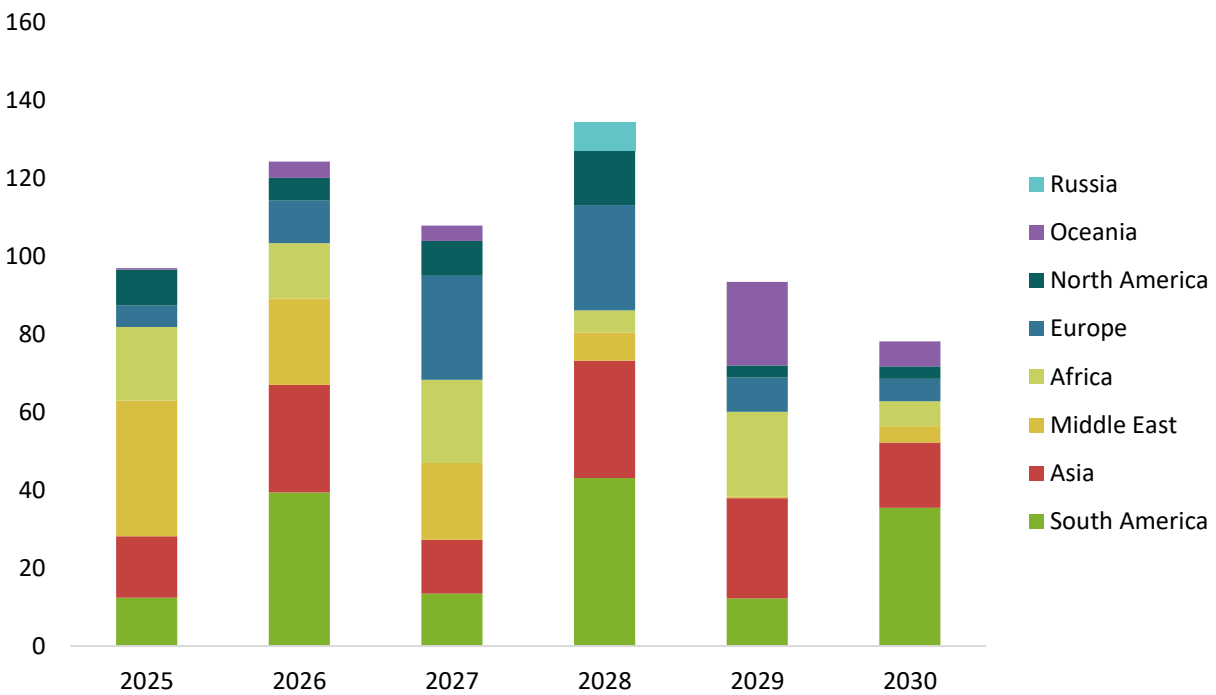
In Figure 11, the projected peak of 142 sanctioned projects in 2027 reflects a clear shift in development strategy toward subsea tiebacks and fixed platforms. Subsea tiebacks, in particular, are expected to drive the most consistent growth through 2028, supported by shorter lead times and strong project economics. In parallel, fixed platforms, especially across the Middle East and shallow-water Asia, continue to provide a stable foundation for global gas supply. Beyond the peak, the decline in project count toward 2030 highlights a broader visibility gap, consistent with trends observed in the capital expenditure (capex) outlook. This reinforces the importance of floaters (FPU, FPSO, FLNG) over the next decade. While they represent a smaller share of currently sanctioned activity, they will be essential to unlocking large-scale resources in frontier basins such as Namibia and Brazil, resources that are critical to closing the projected supply gap by 2050.

Regional epicenters: Where the capital is flowing

Figure 12 highlights a clear shift in global capital allocation toward lower-risk deepwater provinces. While the Middle East remains a key destination, with around $260 billion in planned capital deployment, recent geopolitical developments are already affecting project timelines and execution.

Delays in major projects and reported production disruptions underscore how the region's risk profile is translating into real investment and operational challenges. As a result, the stability premium is no longer just influencing sentiment but is starting to shape capital allocation decisions and the pace of new commitments.

Figure 12: Offshore greenfield sanctioning activity by region (2025-2030)
Billion USD



Source: Rystad Energy ServiceDemandCube Oil & Gas, March release

Offshore greenfield development activity and capital allocation

The Middle East: The fragile anchor

The Middle East remains a cornerstone of global offshore investment, with around $260 billion in planned spending through 2030, but its role is increasingly under pressure. The recent geopolitical escalation has introduced a clear stability premium, raising concerns around disruption risks – particularly at the critical chokepoint of Hormuz.

The impact is already becoming visible at the project level. Delays in Qatar's North Field expansion and reported shut-ins at Saudi Arabia's Marjan and Zuluf fields highlight how operational and execution risks are beginning to translate into real supply constraints. These developments suggest that the region's risk profile is no longer theoretical but is actively shaping timelines and project delivery.

As a result, forward capital allocation is starting to adjust. While core projects will continue to move ahead, sustained uncertainty is likely to redirect part of the region's undeveloped capital toward lower-risk opportunities, particularly in the Atlantic Margin, where projects offer more secure access to global markets.

The Atlantic Margin: The deepwater growth engine

South America and West Africa are increasingly drawing attention as investment considerations broaden beyond higher-risk regions. With relatively stable operating environments and competitive breakeven levels, the Atlantic Margin is well positioned to capture a growing share of longer-term offshore activity.

Recent developments in Guyana and Brazil illustrate this momentum. ExxonMobil's FDP submission for Longtail (Project 8), along with the gas-focused Haimara (Project 9), reinforces the Stabroek block's track record for execution and project delivery. At the same time, Petrobras continues to advance the SEAP (P-81 and P-87) projects, which remain central to Brazil's broader development pipeline.

While it is still early to conclude that capital is materially shifting at scale, the relative attractiveness of these basins, combined with secure access to global markets, suggests they are likely to play an increasingly important role in future offshore investment.

Asia & Oceania: The infrastructure-led gas boom

Asia remains the largest region by project count, but the focus has clearly shifted toward infrastructure-led exploration (ILX) as a way to reduce development risk and accelerate timelines.

Eni's dual FIDs on 18 March 2026, for its North and South Hubs in Indonesia, illustrate this model. By routing South Hub production to the existing Jangkrik floating production unit and sending North Hub gas to the Bontang LNG plant, the projects cut capital intensity by roughly 30% compared to standalone builds. This highlights how subsea tiebacks efficiently deliver new gas volumes. Meanwhile, Papua LNG remains the largest greenfield project in this year's pipeline, with an FID targeted for mid-2026. Despite ongoing execution challenges, its progress shows that operators will still take on significant risk if the resource scale is large enough.

Global offshore growth: A regional view (2026-2030)

A regional view of offshore growth

The offshore landscape is no longer uniform – it is increasingly defined by regional trade-offs between risk, cost and technical complexity. Some basins offer speed and capital efficiency, while others require higher-risk, technology-heavy developments to unlock scale. The table below captures these differences and clarifies where the next wave of offshore growth is most likely to come from.

Table 1: Summary of strategic drivers and technical catalysts by region

Region	Primary Catalyst	Breakeven (USD per barrel) *	2026 Geopolitical Risk	Tech Priority
Brazil (Pre-Salt)	Deepwater Oil / HISEP	$35 - $40	Low	HISEP, FPSO standard hulls, flexible pipe
Guyana (Stabroek Block)	Rapid Phase Development	< $30	low	MPD, FPSO standard hulls
Namibia (Orange Basin)	Frontier Exploration / EFWI	< $45	Low/Med	MPD, FPSO design standards
US (Gulf Of America)	20k PSI / Ultra-Long Tiebacks	$35 - $50	Low	20K XMT and BOP, subsea electrification
Norway (North Sea)	ILX / Electrification	$35 - $50	Low	Platform electrification , EHT flowlines
Middle East (Arabian Gulf)	Mega-Expansions (Zuluf/Marjan)	$20 - $40	High	Modern rig technology, intelligent completions

*Breakeven oil price, including fields that are currently producing, under development and discovered but not sanctioned

Source: Rystad Energy GasMarketCube, Rystad Energy research and analysis, March release

Global offshore growth: A regional view (2026-2030)

Regional integration: A closer Look

The Atlantic Margin (Brazil & Guyana):

The Atlantic Margin continues to benefit from the ongoing shift in capital toward more stable regions. In Guyana, the use of Managed Pressure Drilling (MPD) as a baseline approach has helped mitigate cost inflation by drastically reducing non-productive time and improving penetration rates by up to 30%. In Brazil, the rollout of subsea high-pressure separation (HISEP) is addressing high levels of CO2-rich gas in pre-salt reservoirs. By separating and reinjecting gas at the seabed, the technology eliminates gas processing modules that conventionally account for roughly 60% of topside real estate, making it easier to bring previously stranded volumes into development.

The US Gulf of America: A technology leader

The US Gulf of America has firmly established itself as the global leader in 20k PSI technology, moving from a technical frontier to a deployable commercial standard. With the specialized 20k drillship fleet expanding through the end of the decade, the region is opening access to the Paleogene, one of the largest low-carbon resource opportunities, while also strengthening domestic supply resilience in a more volatile global environment.

Namibia & West Africa: The new frontier

Namibia's Orange Basin has quickly become a benchmark for discovery-led exploration. Advances such as GPU-accelerated elastic full waveform inversion have dramatically shortened seismic processing timelines from roughly a year to just a few weeks, allowing operators to move faster and with greater confidence. At the same time, Modular FLNG is emerging as a flexible solution across West Africa, helping bring remote gas resources to market and offering an alternative to more constrained supply routes.

Norway & East Mediterranean: A stable gas supply base

Norway has firmly established itself as Europe's natural gas supply backbone, while the Eastern Mediterranean and Black Sea are emerging as vital supplementary hubs. With disruptions to traditional flows, developments in areas such as the Mediterranean, Black Sea and the Norwegian Continental Shelf are becoming increasingly central to regional energy security. These areas are no longer just local resource basins – they are critical to maintaining industrial stability across Europe, supporting a strong case for sustained, long-term investment.

Conclusion: The path to 2050

Moving into the second half of the decade, offshore is becoming an increasingly important part of the global energy system. The 2026 supply shock may have disrupted near-term balances, but it does not change the longer-term requirement for continued offshore development.

What can look like oversupply today is, in many cases, a reflection of the long lead times needed to bring new projects online. The record level of project sanctioning in 2026 is not excessive; it is the volume needed to offset future decline and maintain stability in the early 2030s.

Bridging the decline

With an average decline rate of around 6% across existing offshore production, the system requires a steady flow of new capacity just to hold output flat. Given the five to seven-year development timelines for deepwater projects, today's investment decisions are already shaping supply availability later this decade.

A shift in the cost curve

The industry is not simply adding volume, it is gradually improving the overall quality of supply. Technologies such as EHTF, HISEP and 20k PSI systems are enabling offshore projects to compete on both cost and emissions. As a result, newer developments are increasingly displacing higher-cost, higher-carbon sources, contributing to a more efficient supply mix over time.

Why investment must increase

Maintaining balance through 2050 will require sustained investment, with annual spending in the range of $640 billion. In a more uncertain and fragmented market, this level of investment is not discretionary – it is necessary to support system stability. The shift toward regions such as the Atlantic Margin, along with the continued development of subsea-based solutions, reflects the industry is adaptation to both geopolitical risk and long-term demand.

Insights powered by data

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