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United Kingdom

Oil & Gas Report

Includes 10-year forecasts to 2034

Contents

Key View

Key View: *The UK oil and gas sector faces a mixed outlook, influenced by strategic mergers and policy shifts. The Equinor-Shell merger aims to bolster domestic production but awaits regulatory approval. The hike in the Energy Profits Levy to 38% could deter investment, adding pressure to the upstream sector despite slight production recoveries from projects like Penguins and Seagull. The downstream sector sees challenges, exemplified by the Grangemouth refinery closure. Gas production declines and limited storage elevate import reliance, even as demand falls with the shift to renewables.*

Headline Forecasts (United Kingdom 2023-2029)

Indicator	2023e	2024e	2025f	2026f	2027f	2028f	2029f
Crude, NGPL & other liquids prod, 000b/d	733.8	801.7	774.8	740.6	727.2	723.2	701.9
Dry natural gas production, bcm	34.2	30.8	28.9	26.9	25.0	23.3	21.6
Dry natural gas consumption, bcm	63.2	61.0	59.8	58.6	57.4	56.3	55.1
Refined products production, 000b/d	1,110.6	1,099.5	1,011.5	1,001.4	991.4	981.5	971.7
Refined products consumption & ethanol, 000b/d	1,474.7	1,482.4	1,439.7	1,398.4	1,358.4	1,319.5	1,281.9
Brent, USD/bbl	82.18	79.86	76.00	75.00	75.00	75.00	75.00

e/f = BMI estimate/forecast. Source: EIA, BMI

Latest Updates And Key Forecasts

- In October 2024, Rachel Reeves, the UK's Finance Minister, announced in the Autumn 2024 budget that the Energy Profits Levy on North Sea energy producers will increase from 35% to 38% and be extended until March 2030, unless oil and gas prices decline for six consecutive months. Additionally, fuel duty will remain frozen, with the 5p per litre reduction maintained, and an extra GBP500mn pledged for road maintenance.
- In July 2024, the new UK Labour Party government announced a series of proposed additional changes to the fiscal regime covering production in the UK and the UK Continental Shelf. They plan to raise the Energy Profits Levy by 3.0% and increase overall taxes to 78.0%, aligning with Norway's marginal tax rate. The manifesto also called for an end to licensing for the exploration of new oil and gas fields.
- We believe that the deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-standing declines in UK exploration and production, and increasing the country's reliance on imported fuels. Several oil and gas companies have threatened that the increase in the Energy Profits Levy will deter future investments in the UK.
- On January 30, it was announced that the court has ruled that consent for the Rosebank and Jackdaw oil and gas fields in Scotland was granted unlawfully, requiring a new environmental impact assessment that includes downstream emissions. Fresh approval from the UK government is needed before production can begin, amidst ongoing debates on climate implications and energy security. This development creates significant downside risks to our oil production outlook, potentially causing project delays.
- On December 5, Shell UK Limited and Equinor UK Ltd announced plans to merge their UK offshore oil and gas assets to form the UK's largest independent oil producer, equally owned by both companies. The merger is expected to be completed by the end of 2025, aiming to boost production to 200,000–220,000boe/d within five years, up from over 140,000boe/d in 2025.
- Recent years have seen significant declines in the UK's oil production, with an average decline of approximately 11.0% y-o-y from 2020 to 2023. Crude and condensates production fell from 1mn b/d in 2019 to an estimated 646,000b/d in 2023. We anticipate these declines will be stemmed in the short term. We forecast the UK's crude production to increase slightly in 2024 and 2025 to 801,700b/d and 774,800b/d respectively, due to the ramp-up of production at the new Seagull fields, the Penguins redevelopment field, and the Talbot redevelopment project.

- We expect UK gas production to continue its recent trend of heavy declines. We forecast the country's annual gas production will decline by 10.0% y-o-y in 2024 to an annual output of 31.5bcm, with another planned 6.0% y-o-y contraction in 2025. Provisional January–November 2024 gas production data show an impressive 10% y-o-y decline compared to the corresponding period in 2023, indicating further downside risks to our 2024 and 2025 gas production outlook. The UK's annual gas production in 2023 already declined by 9.0% y-o-y to 34.0bcm.
- Over the long term (2025–2034), we forecast UK gas production to decline at 6.9% y-o-y due to low exploratory drilling levels and high natural decline rates. By 2034, we expect production of 15.1bcm of gas. However, it is likely that some new field FIDs or brownfield and/or expansion projects could temper the decline rates.
- We expect the UK's refined fuels production to continue its decline in 2024 and 2025, contracting by 1.0% y-o-y in 2024 and 8.0% in 2025 (following the closure of the Grangemouth refinery in 2025). Output will be weighed down by continued weakness in domestic and regional demand for fuels in the UK and Europe due to a bearish near-term macro outlook.
- The UK no longer imports any Russian crude oil (since 2022 and 2023), following Russia's invasion of Ukraine in 2022. The UK's oil imports are now mostly sourced from Saudi Arabia, Belgium, UAE, South Korea, and the Netherlands.
- Scotland's only oil refinery at Grangemouth will close in 2025 due to inefficiency and declining demand, leading to the loss of around 400 jobs. Petroineos plans to convert the site into an import terminal and explore low-carbon fuel options through Project Willow, supported by GBP20MN in funding from the UK and Scottish governments. Meanwhile, the Stanlow oil refinery in northern England is preparing to increase fuel sales by investing in infrastructure and adding storage capacity in response to Grangemouth's closure. Stanlow will become one of the five remaining UK refineries and is part of the HyNet decarbonisation cluster, with plans to produce blue hydrogen supported by GBP20mn in government funding to meet long-term conventional oil product needs.
- Our Country Risk team has revised the GDP growth forecast downward in response to broad-based US tariffs. The projections are now 1.2% for 2025 and 1.3% for 2026, down from 1.4% and 1.8%, respectively. While this decline is notable, it remains relatively marginal compared to other regions. As a result, we have correspondingly revised down our fuel consumption outlook by a 0.2% downward revision in 2025 and 0.5% in 2026.
- The UK government is easing EV sales targets to support the car industry amid a new 25% US tariff on car imports, impacting the UK as a major exporter. While the ban on new petrol and diesel car sales remains set for 2030, manufacturers now have more flexibility in meeting annual EV sales targets. This includes the ability to make up shortfalls in subsequent years and a reduction in fines for not meeting emissions standards. However, our autos team does not anticipate this development having any significant implications on EV penetration in the market, and as a result, we have made no adjustments to our fuel consumption outlook in lieu of this news.
- Dutch TTF natural gas prices closed at EUR31.75/MWh on April 29, driven by a combination of potential economic strain from tariffs and reduced heating demand at the start of the shoulder season. While prices are currently steady, storage pressures are expected to elevate prices from Q2 to Q4 due to a significant gap in EU gas inventories, approximately 58bcm, needed for replenishment by the end of the year. The forecast for 2025 remains at EUR40/MWh, accounting for the impact of refilling inventories. For 2026, a more bearish outlook is anticipated, with prices averaging EUR32/MWh. As Dutch TTF natural gas prices remain steady, with pressures expected to push them higher due to EU inventory gaps, UK gas consumers may face increased energy costs, particularly if these trends reflect on local markets. This could create upward pressure on heating and electricity costs.
- As of January 2025, the UK is facing critically low gas storage levels, with storage dropping from 57.4% on January 1 2025 to 32.9% by January 20 2025, compared to 82.0% during the same period in 2024. This limited capacity is leading to higher gas prices for households and increased competition for LNG. Additionally, natural gas's share in electricity generation is expected to decline from 32.7% in 2024 to 6.7% by 2034 as the UK shifts towards decarbonisation and renewable energy sources.
- We anticipate UK gas demand will continue to contract in 2024 and 2025, although at a much lower extent than the declines seen in the previous two years. We forecast total gas consumption in the country to decline by 3.5% y-o-y in 2024 and 2.0% in 2025. This will partly be driven by the strong base effects of the consecutive heavy declines seen in both 2022 and 2023. To date, provisional January–June 2024 data show gas demand contracted by 4.6% compared to the corresponding period in 2023. The continuation of elevated gas prices in the country in the near term, which has been a key driver of reductions in gas demand in recent years, will continue to weigh on gas demand over the remainder of 2024 and into 2025.

SWOT

Oil & Gas SWOT

Strengths	Weaknesses
• Proven hydrocarbon potential that is well supported by an established offshore service industry. • Competitive company landscape - more than 140 companies engaged in UK offshore operations.	• Weak short-term economic outlook for the UK expected to weaken consumption in the short term. • High degree of instability and uncertainty regarding UK fiscal policy relating to oil and gas industries are likely to have a negative effect on investor sentiment. This is re-enforced following the Labour Party victory at the July 2024 general elections. • Continued weakness in exploration levels could reinforce the long-term production decline trends across the petroleum sector. • Increasing dependence on imports for energy requirements. • Downside risk to refining capacity as domestic demand falls and weakness in the pound make fuel imports more expensive. • Lower gas storage capacity leaves the UK vulnerable in high-demand peaks.
Opportunities	**Threats**
• First UK licensing round launched in three years in October 2022 and finalised in October 2023 offers new exploration opportunities. • Underexplored West of Shetlands and near-field resources provide exploration and production opportunities. • The need to decommission legacy oil and gas infrastructure to support supply chain firms and end-of-life asset management. • Room for natural gas assets to support the UK's blue hydrogen strategy. • The UK's high LNG import capacity leaves it in a strong position to benefit from gas sales to Europe via interconnectors.	• Future alterations in fiscal policy, which potentially imposes an even larger tax burden on the UK oil and gas industry. • Continued decline in oil and gas production will lead to an inflated energy import bill. • Rising exploration and production costs could see investment increase without a corresponding rise in total output. • Uncertain geology, a restrictive regulatory environment, and waning social and political support will irreversibly hinder shale gas commercialisation efforts. • A strong push from the UK to be seen as a global leader on the green transition threatens future oil and gas investments through legal challenges by environmental organisations. • Changing sentiment from the Scottish government and environmental pressure threaten involvement of firms concerned about their low carbon credentials.

Industry Forecast

Upstream Exploration

Key View: *The outlook for exploration prospects in the mature UK market has worsened in the context of the recent Labour Party victory at the July 2024 general elections. Labour had pledged in its manifesto to extend the Energy Profits Levy, on the North Sea oil and gas industry until the end of the current parliament and increase the rate from 35% to 38%, bringing the total headline rate of tax on oil and gas profits to 78%. In addition, the Party had also planned to end new exploration license awards in the UK North Sea. While future exploration had posed upside risk to our outlook (notably following the 33rd licensing round launched late 2022 and former prime minister Rishi Sunak's 2023 commitment to future yearly rounds), Labour's licensing ban will have put paid to this should it be implemented. Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely further deter investors, providing an increasing bearish outlook for the UK exploration scene.*

Latest Updates

- In October 2024, Rachel Reeves, the UK's Finance Minister, announced in the Autumn 2024 budget that the Energy Profits Levy on North Sea energy producers will increase from 35% to 38% and be extended until March 2030, unless oil and gas prices decline for six consecutive months. Additionally, fuel duty will remain frozen with the 5p per litre reduction maintained, and an extra GBP500mn pledged for road maintenance.
- In July 2024, the new UK Labour Party government announced a series of proposed additional changes to the fiscal regime covering production in the UK and the UK Continental Shelf. They plan to raise the Energy Profits Levy by 3.0% and increase overall taxes to 78.0%, aligning with Norway's marginal tax rate. The manifesto also called for an end to licensing for the exploration of new oil and gas fields.
- We believe that the deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-running declines in UK exploration and production and increasing the country's reliance on imported fuels. Several Oil & Gas companies have threatened that the increase in the EPL will deter future Oil & Gas investments in the UK.
- Shell's preliminary drilling results at the Selene exploration well in the UK's North Sea indicate the presence of gas in a 160m thick section of Leman Sandstone; operations continue with further logging and fluid sampling to confirm commercial viability, potentially leading to field development planning without additional appraisal drilling, while Deltic Energy holds a 25% stake in the prospect, estimated to hold gross P50 prospective resources of 318bcf with a 69% geological chance of success.
- Future exploration had posed upside risk to our outlook, but Labour's licensing ban will have put paid to this should it be implemented. Admittedly, mature acreage tends not to yield major new discoveries. However, production can often be supported via near-field exploration and satellite developments tied into existing infrastructure. The ban may curb the economic lifespan of existing reservoirs and lead to the earlier decommissioning of existing platforms and pipelines.
- Two new exploration wells are planned for drilling by late 2024 or early 2025, as of updates by operators Harbour Energy and Petrogas. As of August 2024, data show only one exploration well has been drilled to date in 2024.
- In May 2024, the North Sea Transition Authority completed the final tranche of the 33rd licensing round, offering companies another 31 permits. That followed 27 licences offered in October 2023 and 24 in January 2024. Shell, Equinor, BP, TotalEnergies and NEO are among the 17 separate companies that were offered the blocks in the early 2024 second tranche.
- In October 2023, the North Sea Transition Authority (NSTA) announced that it had awarded 27 new licences as part of the country's 33rd oil and gas licensing round, which was launched in October 2022.

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- UK government policy on hydraulic fracturing (fracking) has been highly erratic over the course of 2022 and 2023 due to historically high levels of volatility experienced recently in British politics. Former UK prime minister Liz Truss had lifted the moratorium on fracking, introduced in 2019. However, within the first week of coming to power, former Prime Minister Rishi Sunak confirmed that he would keep the ban on fracking in place. New Prime Minister Keir Starmer, who led a Labour Party win in the July 2024 general elections will also maintain the ban on hydraulic fracturing, offering no upside risks to exploration for shale gas over the coming years.

Structural Trends

New Labour Policies Set To Further Negatively Impact UK Oil & Gas Sector

In October 2024, Rachel Reeves, the UK's Finance Minister, announced key policies for the oil and gas sector in the Autumn 2024 budget, confirming the EPL increase and extension, as well as extending the frozen fuel duty trend. The confirmed policies are as follows:

1. **Windfall Tax Uplift**: It is confirmed the Energy Profits Levy on North Sea energy producers will increase from 35% to 38%, as promised in Labour's general election manifesto. Initially set at 25% by Rishi Sunak in 2022 and later increased to 35% by Jeremy Hunt in early 2023, the levy will now be extended until March 2030, unless oil and gas prices decline for six consecutive months.
2. **Fuel Duty**: Despite the ongoing cost of living crisis, fuel duty will remain frozen, continuing a trend since 2011. The 5p pence per litre reduction from March 2022 will also be maintained, costing over GBP3bn in 2025. Additionally, Reeves pledged an extra GBP500mn for road maintenance.

Upon the Labour governments election their manifesto highlighted the following changes to the UK's fiscal regime:

- Extend the Energy Profits Levy (EPL) from March 2028 to March 2030;
- Increase the EPL by 3% from November 2024 onwards, bringing the marginal tax rate to 78%, in line with Norway;
- 'Close the loopholes' in the EPL and remove 'generous investment allowances';
- Maintain the Energy Security Investment Mechanism (ESIM); and
- End licensing for the exploration of new oil and gas fields.

These changes to the tax structure apply specifically to the profits earned on the production of oil and gas either onshore UK or in the UK Continental Shelf (UKCS) and so the new legislation will not affect the international operations of firms operating in the UK. Nevertheless, it will likely significantly impact on company cash flows, while further increasing fiscal uncertainties.

The current fiscal regime comprises a 30% corporation tax, a 10% supplementary charge, and a 35% EPL. The profits these apply to are ringfenced and so the various taxes cannot be offset by losses elsewhere in the business. Labour policies will increase the fiscal burden on companies operating in the UK, straining profitability in the oil and gas sector. The level of government take is already among the highest in the world and arguably at odds with the country's mature asset base and declining output.

Furthermore, in its manifesto, Labour also pledged to close the 'loopholes' in the EPL. Although it is not entirely clear what this entails, it seems likely that they intend to end the current investment expenditure uplift, which stands at 80% for decarbonisation investments and 29% for other expenditures. Qualifying expenses include capital spending as well as certain operating costs and lease payments. This is highly significant as it will impact on net revenues, not just profits. Any implicit tax on revenues will be poorly received by the industry and will likely act as a strong disincentive for investment. UK-focused players are already voicing concerns that under Labour's new fiscal regime the capital costs of new projects may be impossible to recoup. While the new policies will align the UK with Norway's marginal tax rate, it should be noted that Norway also offers tax rebates set at 100% of a company's capital expenditures, which Labour seemingly will not. This dramatically alters the calculus for investment.

Producers are also grappling with elevated uncertainties. Given the long lead times and extended payback periods that typify the Oil & Gas sector, forward transparency is crucial in fostering investment. Repeated changes in the fiscal terms governing upstream projects in the UK over recent years have done much to damage investor sentiment. The ESIM was designed to combat this – to 'give the oil and gas sector certainty to raise capital and invest in new and existing projects'. It exempts companies from the EPL when oil and gas prices concurrently fall below the historical 20-year average for two consecutive quarters; that is, USD71.4/bbl for Brent and GBP0.54/therm for NBP. However, given that this scenario seems unlikely to occur in the foreseeable future, the policy has done little to bolster confidence.

Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors. The UK was already struggling to compete for capital on a global scale. Against the backdrop of the broader energy transition, the capital allocation process is highly competitive, and companies are keeping a laser-like focus on commercial breakevens. On average, UK oil & gas projects are relatively costly and will become more so under a Labour government.

Future exploration posed upside risk to our outlook, but Labour's licensing ban will have put paid to this. Admittedly, mature acreage tends not to yield major new discoveries. However, production can often be supported via near-field exploration and satellite developments tied into existing infrastructure. The ban may curb the economic lifespan of existing reservoirs and lead to the earlier decommissioning of existing platforms and pipelines.

2022-2023 Windfall Tax Already Hurt Investment Environment Prior To Labour-Win

Former prime minister Sunak's government had already imposed in May 2022 a windfall tax (called the Energy Profits Levy) on North Sea oil and gas industry, as companies' earnings increased significantly alongside fuel prices following Russia's invasion of Ukraine in early 2022. By late 2022, the levy was at a new 35.0% surcharge on profits made from the oil & gas sector. This was on top of the 40.0% tax already paid by the industry. In order to offset the levy, a new investment allowance was also introduced, with the goal of incentivising re-investment into the UK. This raised the effective tax relief on money invested from GBP46 to GBP91.40 per GBP100 invested.

We had already noted the decision to extend the imposition of the levy from 2025 until March 2028 would be unlikely to instill confidence within the industry, given the ease with which the government has extended the original timeline. The market had originally priced in a one-off windfall tax, but this has transformed into a multi-year proposaln significantly changing the outlook for industry investors. For example, following the proposed push-back in the date, BP stated that because the levy was not a one-off measure, it would need to assess the impact of the levy and tax relief on its North Sea renewable and low carbon investment plans, placing GBP18.0bn of investment at risk. This is unsurprising, given that oil and gas companies plan spending and investments for the long term and desire stability in fiscal regimes.

In addition, we also noted that the effect of the tax to be felt mostly by UK independents, rather than on the majors such as BP and Shell, despite specific restrictions on offsetting previous years' losses against the tax bill. Expensive decommissioning costs have allowed larger majors with ageing asset bases to negate most or all of their tax bill in recent years, often leading to negative tax bills that can be carried over. The windfall tax specifically blocks the use of previous years negative tax bills carried over to offset the tax impact, which most greatly impacts the majors. Due to their diversification, the majors will still be less impacted by the tax than UK independents.

The new Labour government's further extension and further increase of the tax EPL rates will further damage the outlook for the UK's exploration and production sector (*see above*).

UK 33rd Offshore Licensing Round Likely To Have Negligible Effect On Exploration Activity

In 2022, the NSTA announced the first licensing round in almost three years (the 33rd round), in which it was expected to award more than 100 licences in the UK North Sea. As part of the round, it offered 898 blocks and part-blocks that are located predominantly in the West of Shetland, Northern North Sea, Central North Sea, Southern North Sea and East Irish Sea. We believe that this most recent licensing round is likely to have a negligible effect on exploration activity in the UK north sea and therefore fail to reverse the sharp downward trend in exploration that has occurred in recent years. In May 2024, the North Sea Transition Authority completed the final tranche of the licensing round, offering companies 31 permits. That followed 27 licences offered in October 2023 and 24 in January 2024.

Given that the UK North Sea is one of the oldest oil and gas producing basins in the world, the maturity of the basin makes it unlikely that any new large discoveries will be made, thereby disinclining companies from engaging in exploration activity. In this regard, it is important to note that not since the 27th licensing round in 2012 has there been an exploration block that has yielded a significant commercial find.

The recent rise in the Energy Profits Levy from 25.0% to 35.0% in November 2022, bringing the headline tax rate to 75.0%, has also further damaged sentiment in the UK, set to be further impacted by the new Labour government in place since mid-2024. While former prime minister Rishi Sunak has stated his party's commitment to future annual auctions, the party lost the July 2024 general elections, and a Labour led government is now in place, with manifesto promises of higher EPL taxes and an end to new licensing. New Prime Minister Keir Starmer's pledge not to revoke existing drilling permits is set to leave intact the dozens of new oil and gas licences already offered and signed by the former Conservative-led government. However, the future of future licensing is now strongly under doubt.

A Difficult Exploration Scene Going Forward

Despite the more robust price environment, the marginal size of new discoveries and high industry costs have rendered rates of post-tax return in the UK uncompetitive compared to other regions. Symptomatic of these problems, exploration activity has been weak over the past few years, placing increased strain on the UK's long-term production outlook.

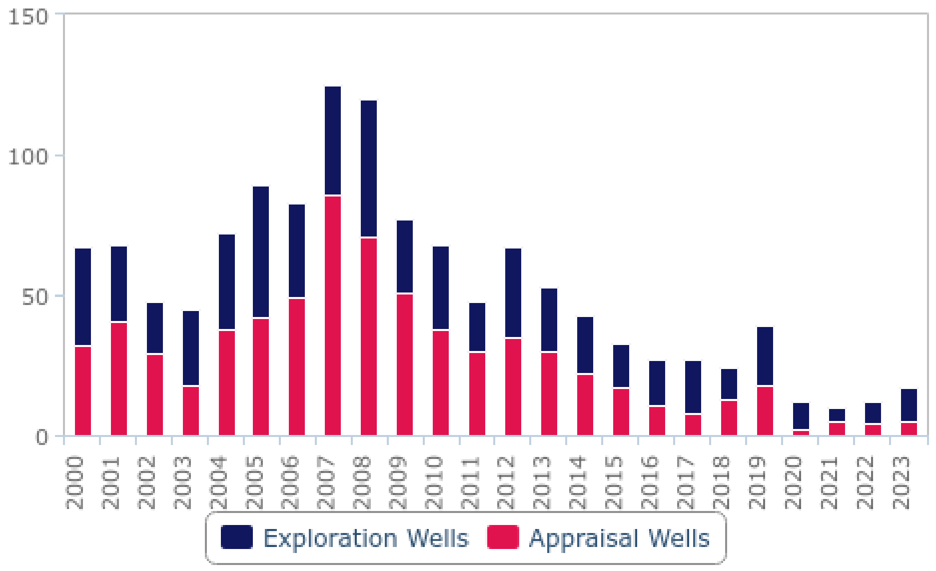
More broadly, oil and gas exploration and appraisal in the UK offshore is still occurring at far lower levels than in previous years, as drillers choose to focus on development rather than on new exploration, or to move out of the North Sea altogether. The outlook on future capex on exploration and appraisal in the UK suggests that this trend could potentially get worse, as forecasts produced by the NSTA suggest that spending on UK exploration and appraisal is set to average around GBP0.36bn per annum between 2023 and 2028. This would be almost a third less than the GBP0.5bn per annum averaged between 2018 and 2022. This supports our view that the licensing round is unlikely to reverse the trend in which we are currently experiencing record low levels of exploration activity.

The North Sea's Last Frontier: West Of Shetland

The West of Shetland area in the UK North Sea remains the least developed and least mature area on the UKCS with few producing fields. Thus, the area offers arguably the largest remaining exploration potential for significant new finds in the UKCS in terms of exploration opportunities. Important recent discoveries by Hurricane Energy and past success by BP and TotalEnergies emphasise the prospectivity of the below-ground resource base. Commitments to develop Hurricane's Greater Lancaster Development and drilling by Equinor, Nexen and BP reflect exploratory interest in the area. However, downside risks remain to the area's potential, as environmental pressure and turning Scottish government sentiment affect investment in the area.

Minimal Exploration Raising Red Flag For Future Growth

UK - Offshore Exploratory Wells Drilled (2000-2023)



Source: Oil & Gas UK, BMI

We believe that exploration interest in the West of Shetland area will be higher than in other areas in the UKCS, as it provides the highest potential of significantly large new discoveries, as proven by Hurricane Energy's notable discoveries across 2016. This is significant due to the requirement of new discovery size to be sufficiently large to offset exploratory risk and ensure favourable project economics for future developments.

Unconventional Gas

Unconventional gas - CBM and shale gas - are an other source for UK's gas reserves. The British Geological Service estimates that, at a yield of 10.0%, the UK's recoverable CBM resources are about 290bcm.

Estimates for recoverable shale gas resources are more volatile. The July 2013 EIA Assessment of Technically Recoverable Shale Oil and Shale Gas Resources estimates recoverable shale gas resources in the UK to be 728bcm, with the vast majority in the Northern carboniferous Bowland-Hodder region. In late June 2013, the British Geological Survey estimated under its central scenario that the Bowland-Hodder shale formation could contain some 37.6tcm of gas-in-place. While it did not provide estimates for recoverable shale gas resources, this would represent some 1,052bcm of recoverable gas at a 10% recovery rate.

The 2010-2016 Conservative-led coalition government under Prime Minister David Cameron was very keen to promote shale gas exploration, putting in place attractive fiscal and community incentives to accelerate exploration and placate local opposition, notably:

- A new onshore tax allowance reducing the effective rate on shale gas production income from 62.0% to 30.0%.
- Substantial corporation tax exemptions to companies that have undertaken exploration and appraisal activities but have not begun production.
- The creation of a reinvestment tax relief that exempts from taxation gains made on the disposal of assets used in the course of oil and gas exploration and appraisal activities in the case where the proceeds of these disposals are then applied for the same purposes.
- Promises to provide communities that host shale gas sites USD150,500 per site and up to 1% of all revenues from production.

- Provisions that local councils can keep 100% of business rates from developed sites to boost local support for fracking.

By the end of 2019, the UK government announced a halt on all hydraulic fracturing activity in the country. The decision follows the publication of a report by the Oil and Gas Authority, which found that it is not currently possible to accurately predict the probability or magnitude of earthquakes linked to fracking operations. In August 2019, an event with a magnitude of 2.9 (which was bigger than the event in 2011 which triggered a seven-year moratorium on fracking) saw operations halted at the site.

In September 2022, the former Truss government announced plans to lift the ban on fracking as part of a broader package of policy measures aimed at raising UK's energy security through investment in home grown energy sources. In mid-October 2022, legislation was passed in Parliament that would have enabled the shale gas drilling for the first time since 2019.

Within a week of becoming the UK Prime Minister on October 25 2022, Rishi Sunak confirmed that he would reverse the action taken by former prime minister Liz Truss and re-introduce the ban on hydraulic fracturing that existed previously. We note that the erratic nature of recent UK government regulatory policy on domestic shale gas extraction, in which the moratorium on shale gas drilling had been lifted and then re-imposed in less than a fortnight, is likely to damage sentiment within the UK shale gas industry. This is due to the fact that a stable and relatively predictable regulatory policy plays an important part in giving confidence to companies and investors within the sector in order to make final investment decisions. The new Labour govenrnment led by Keir Starmer following the July 2024 general elections will maintain the ban on hydraulic fracturing in place.

Upstream Projects

Major Upstream Projects

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Golden Eagle Area Development (GEAD)	Block 20/1S: Golden Eagle, Block 20/1N: Peregrine, Block 14/26a: Solitaire	Oranje Nassau (0.47%), Dyas (4.74%), China National Offshore Oil Corporation (CNOOC) (36.5%), Maersk Oil (31.56%), Suncor (26.69%)	2014	Production	70,000	na
Blocks 205/21a, 205/22a and 205/26b	Lancaster	Hurricane Exploration (100%)	2019	Development	17,000	na
Block 20/02a	Blackbird	CNOOC (90.6%), Atlantic Petroleum (9.4%)	2011	Decommissioned	15,000	na
Greater Stella Area: Licence P.011, Block 30/6a & 29/10a	Stella, Harrier, Hurricane, Twister	Ithaca Energy (54.66%), Dyas (25.34%), Petrofac (20%)	2017	Production	25,000	na
Block 22/14b	Huntington	Premier Oil (65%), Noreco (20%), Iona Energy (15%)	2013	Production	34,500	na
Block 22/25a, Licence P111	Culzean	JX Nippon Oil & Energy Corporation (18.01%), BP (32%), Maersk Oil (49.99%)	2019	Development	90,000	na
PEDL137, Weald Basin	Horse Hill	Magellan Petroleum (35%), Horse Hill Development (65%)	na	Appraisal	na	na
PEDL201, Nottinghamshire	PEDL201	Celtique Energie Petroleum (32.5%), Terrain Energy (12.5%), Egdon Resources (32.5%), Union Jack Oil (10%), Corfe Energy (12.5%)	na	Exploration	na	na
Licence P1430: Block 28/9a & 28/10c	Catcher, Varadero and Burgman	MOL Group (20%), Premier Oil (50%), Cairn Energy (20%), Dyas (10%)	2017	Production	60,000	na
Block 205/26a	Solan	Chrysaor (40%), Premier Oil (60%)	2016	Production	25,000	na
Block 210/29a and 210/30a	Cladhan	MOL Group (33.5%), TAQA (Abu Dhabi National Energy Company) (64.5%), Sterling Energy (2%)	2015	Production	17,000	na
Block 206/7a, 206/12, 206/8, 206/13a, and 206/9	Clair	Chevron (19.4%), ConocoPhillips (24%), Shell (28%), BP (28.6%)	2005	Upgrade/EOR	120,000	1
PEDL 162	PEDL 162	Reach Coal Seam Gas	na	Exploration	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
		(20%), Ineos (80%)				
Block 21/20a	Cook	Ithaca Energy (61.4%)	2000	Production	20,000	na
Block 23/22a and 23/27	Pierce	Shell (92.5%), Ithaca Energy (7.5%)	1999	Production	20,000	na
Wytch Farm	Wytch Farm	Ithaca Energy (7.4%), Perenco (50.1%), Premier Oil (30.1%), Maersk Oil (7.4%), China Petroleum & Chemical Corporation (Sinopec), Repsol	1979	Production	19,000	na
Block 15/21 and 15/22	Scott	CNOOC (41.9%), MOL Group (21.83%), Dana Petroleum (20.65%), Apache Corporation (10.47%), Maersk Oil (5.16%)	1993	Production	na	na
Block 15/22	Telford	CNOOC (80.4%), MOL Group (1.6%), Apache Corporation (15.65%), Maersk Oil (2.36%)	1996	Production	na	na
Block 206/4a, Licence P1453	Edradour	SSE (20%), Orsted A/S (20%), TotalEnergies (60%)	2017	Production	17,000	na
Block 214/30a, Licence P1195	Glenlivet	SSE (20%), TotalEnergies (60%), Orsted A/S (20%)	2017	Production	21,000	na
PL1/10	PL1/10	Tudor Investment Corporation (10%), Petro River (9%), Horizon Oil (16%), Ermine Resources (15%), Brigantes (10%), Terrain Energy (10%), Baron Oil (10%), Infrastrata (20%)	na	Exploration	na	na
PEDL 180	Wressle	Egdon Resources (25%), Europa (33.3%), Celtique Energie Petroleum (33.3%), Union Jack Oil (8.3%)	na	Discovery	na	na
Block 113/27c, 113/26b, PL 1482	Doyle Prospect	Centrica (45%), Zennor Petroleum (35%), Serica Energy (20%)	na	Exploration	na	na
BritSats, Block 15/29b	Callanish	Chevron (16.5%), ConocoPhillips (83.5%)	2008	Production	na	na
BritSats, Block 21/3a	Brodgar	Chevron (25%), ConocoPhillips (75%)	2013	Production	na	na
Block 15/29a, 15/30, 16/26,	Britannia	ConocoPhillips (58.7%), Chevron (32.3%), Mitsui	1998	Production	na	3.8

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
16/27a, and 16/27b		(9%)				
Licence P1242, Block 48/1a	Platypus	First Oil Expro (11%), Parkmead Group (15%), CalEnergy Resources (15%), Dana Petroleum (59%)	na	Appraisal	na	na
Greater Alwyn: Block 3/15	Islay	TotalEnergies (100%)	2012	Production	15,000	na
Greater Alwyn: Block 3/15	Jura	TotalEnergies(100%)	2008	Production	50,000	na
Greater Alwyn: Block 3/15	Forvie North	TotalEnergies(100%)	2005	Production	na	0.7
J Block	Judy/Joanne	Shell (30.5%), ConocoPhillips (36.5%), Eni (33%)	1997	Production	40,000	na
J Block	Jade	Siccar Point Energy (5.57%), Shell (35%), ConocoPhillips (32.5%), Chevron (19.93%), Eni (7%)	2002	Production	20,000	2.1
Licence P2070	Block 28/4a	Nautical (36%), Premier Oil (54%), Dyas (10%)	na	Exploration	na	na
Licence P2040	Block 29/11	Government of UK	na	Suspended	na	na
Licence P2077	Block 28/8a	Nautical Petroleum (36%), Premier Oil (54%), Dyas (10%)	na	Exploration	na	na
Licence P2086	Block 28/9b and 28/14	Government of UK	na	Suspended	na	na
Licence P198, Block 3/29	Rhum	BP (50%), National Iranian Oil Company (NIOC) (50%)	2005	Production	na	3
Block 9/13	Beryl	Apache Corporation (60.6%), Shell (39.4%)	1976	Production	120,000	4.5
Licence P103	Skene	Shell (34%), Apache Corporation (66%)	2002	Production	25,000	1.8
Licence P103	Maclure	Nobel Oil Group (7.59%), Maersk Oil (38.19%), Taqa Bratani (37.04%), Apache (17.18%)	2002	Production	8,000	na
Forties Complex, Block 21/10b	Tonto	Apache Corporation (100%)	2013	Production	20,000	na
Forties Complex, Block 21/10	Maule	Apache Corporation (100%)	2010	Production	11,750	na
Forties Complex, Block 22/6a	Bacchus	Apache Corporation (50%), Zennor Petroleum (20%), Endeavour Energy (30%)	2012	Production	18,000	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Block 23/26a, 23/26b	Erskine	Serica Energy (18%), BG Group (32%), Chevron (50%)	1997	Production	30,650	1.2
P1916 Licence	Isle of Wight	UK Oil & Gas (100%)	na	Exploration	na	na
Licence P1724	Peagasus	Third Energy (45%), Centrica (55%)	na	Appraisal	na	na
PEDL241	PEDL241	Union Jack Oil (20%), Egdon Resources (80%)	na	Exploration	na	na
Licence P1765, Block 30/24c & 30/25c	Alma & Galia	Kuwait Foreign Petroleum Exploration Company (35%), EnQuest (65%)	2015	Production	20,000	na
Licence P241, Block 21/1a	Buchan	First Oil Expro (0.91%)	1981	Production	32,000	na
Block 211/29	Brent	Shell (50%), ExxonMobil (50%)	1976	Decommissioned	500,000	10.6
PEDL 181	PEDL 181	Celtique Energie Petroleum (25%), Egdon Resources (25%), Europa Oil & Gas (50%)	na	Exploration	na	na
PEDL 126 Licence, Weald Basin	Markwells Wood	UKOG (100%)	na	Appraisal	na	na
P1799 Licence	P1799 Licence	Government of UK	na	Suspended	na	na
Licence P2260, Block 48/22c	Hambleton	Independent Oil and Gas (100%)	na	Appraisal	na	na
Block 22/9, 22/10, 22/14	Everest, Everest East	Shell (100%)	1993	Production	16,000	na
Licence P101, Block 23/21a	Lomond	Shell (100%)	1993	Production	6,000	na
Armada Area: Block 22/5	Fleming	Shell (76.4%), Centrica (23.6%)	1997	Production	na	na
Armada Area: Block 22/5b	Drake	Shell (76.4%), Centrica (23.6%)	1997	Production	na	na
Armada Area: Block 22/5	Hawkins	Shell (76.4%), Centrica (23.6%)	2001	Production	na	na
Armada Area: Block 22/5	Seymour	Shell (36%), Centrica (64%)	2003	Production	na	na
Armada Area: Block 16/29	Maria	Shell (57%), Centrica (43%)	2007	Production	na	na
Block 30/2a, 30/2d and 30/3a	Jackdaw	Siccar Point Energy (26%), Shell (74%)	na	Appraisal	na	na
Block 14/20, 15/21a & 15/	Perth-Dolphin-Lowlander (PDL)	Parkmead Group, Faroe Petroleum, Atlantic	2019	Appraisal	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
21c		Petroleum				
Block 44/24b, 44/18d, 44/23f and 44/19f	Wingate	XTO United Kingdom (15.5%), Gas-Union GmbH (15%), Gazprom (20%), Wintershall (49.5%)	2011	Production	na	0.7
P1972	Block 3/9e, 3/10a, 3/15b	Government of UK	na	Suspended	na	na
Thames Complex, P037	Thames, Bure Oscar, Bure West, Thurne, Wensum, and Yare	Centrica (10%), Perenco (23.33%), Tullow Oil (66.67%)	1986	Decommissioned	na	4.2
P037, Block 49/28a	Thurne	Centrica (13.04%), Tullow Oil (86.96%)	na	Decommissioned	na	na
P039, Block 53/04d	Wissey	Faroe Petroleum (18.75%), First Oil Expro (18.75%), Tullow Oil (62.5%)	na	Decommissioned	na	na
Block 53/04b, 53/03c	Horne & Wren	Tullow Oil (50%), Centrica (50%)	na	Decommissioned	na	na
Block 49/24F1, 49/29a	Gawain	Perenco (50%), Tullow Oil (50%)	1995	Decommissioned	na	na
Elgin-Franklin, Block 29/4d, 29/5b	Glenelg	Shell (14.7%), Premier Oil (18.6%), Eni S.p.A (8%), TotalEnergies (58.7%)	2006	Production	30,000	na
Quad 204 and 205	Loyal	Shell (50%), BP (50%)	1998	Upgrade/EOR	25,000	na
P.1889 Licence	P.1889 Licence	Government of UK	na	Suspended	na	na
Licence P1943, Block 13/24c	Bagpuss Prospect	Groliffe (6.63%), Encounter Oil (13.27%), Premier Oil (40.1%), North Sea Energy (15%), Maersk Oil (25%)	na	Discovery	na	na
Block 9/11a & 9/11b	Mariner, Mariner East	JX Nippon Oil & Energy Corporation (20%), Siccar Point Energy (8.9%), Dyas (6%), Equinore (65.11%)	2018	Development	55,000	na
Licence PEDL005 (R), Humber Basin	Keddington	Cairn Energy (10%), Union Jack Oil (10%), Terrain Energy (35%), Egdon Resources (45%)	2007	Production	na	na
Licence PEDL005 (R), Humber Basin	Louth	Cairn Energy (10%), Union Jack Oil (10%), Terrain Energy (15%), Egdon Resources (65%)	na	Exploration	na	na
Licence PEDL005 (R), Humber Basin	North Somercotes	Cairn Energy (10%), Union Jack Oil (10%), Terrain Energy (15%), Egdon Resources (65%)	na	Exploration	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Anasuria Cluster	Teal, Teal South, Guillemot A	Hibiscus (50%), Ping Petroleum (50%)	1996	Production	na	na
Block 204/19	Suilven	Shell (25%), Siccar Point Energy (75%)	na	Appraisal	na	na
Licence P1028 and P1189	Cambo	Siccar Point Energy (70%), Shell (30%)	na	Discovery	na	na
P1190, Block 204/13a	Tornado	Government of UK	na	Suspended	na	na
Licence P967	Licence P967	OMV (17.5%), Orsted A/S (32.5%), TotalEnergies (50%)	na	Discovery	na	na
Jupiter Complex	Ganymede, Sinope, Callisto, Europa and NW Bell	ExxonMobil (50%), Equinor (30%), ConocoPhillips (20%)	1995	Production	na	0.5
Douglas	Douglas	Eni (100%)	1996	Production	40,000	na
Lennox	Lennox	Eni (100%)	1996	Production	na	na
Hamilton	Hamilton	Eni (100%)	1995	Production	na	na
Hamilton North	Hamilton North	Eni (100%)	1995	Production	na	na
Licence P.037, Block 48/29	Hewett	Perenco (10.69%), Eni (89.31%)	1969	Production	na	8.6
Block 15/24b	MacCulloch	Repsol (6%), Noble Energy (14%), Eni (40%), ConocoPhillips (40%)	1997	Decommissioned	60,000	na
Licence P1620	Block 22/19c	Mitsui (20%), Eni (40%), JX Nippon Oil & Energy Corporation (25%), Serica Energy (15%)	na	Exploration	na	na
Licence 2185	Block 22/19e	Mitsui (42.86%), Eni (57.14%)	na	Exploration	na	na
Licence P2191	Block 30/1b	Eni (100%)	na	Exploration	na	na
Licence P312	Utgard (Alfa Sentral)	Kuwait Foreign Petroleum Exploration Company (6.2%), Lotos Exploration and Produkction Norge AS (17.36%), Equinor (76.44%)	2019	Development	na	na
Brae Complex: Block 16/7a, 16/3a and 16/3b	South Brae, North Brae, Central Brae, West Brae, East Brae, Braemar	Marathon Oil, BP, TAQA (Abu Dhabi National Energy Company), Centrica, JX Nippon Oil & Energy Corporation, Engie	1983	Production	115,000	3.5
Block 16/7a	Beinn	JX Nippon Oil & Energy Corporation (6.3%), Centrica (8%), TAQA (Abu Dhabi National Energy Company) (18%), BP	na	Production	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
		(27.7%), Marathon Oil (40%)				
Blocks 21/8a, 21/12c and 21/13a	Scolty/Crathes	MOL Group (50%), EnQuest (50%)	2016	Production	20,000	na
Heather/Broom	Heather/Broom	EnQuest, Wintershall, Ithaca Energy	1978	Production	36,000	na
Block SE72 and SE73, Cleveland Basin	Block SE72 and SE73	Shale Petroleum (50%), Europa Oil & Gas (50%)	na	Exploration	na	na
Block SE46c	Block SE46c	Upland Resources (16.67%), Shale Petroleum (16.66%), Ineos (50%), Europa Oil & Gas (16.66%)	na	Exploration	na	na
Block SE99a and TA09, Cleveland Basin	Block SE99a and TA09	Arenite Petroleum (5%), Petrichor Energy (12.5%), Egdon Resources (17.5%), Third Energy (20%), Shale Petroleum (22.5%), Europa Oil & Gas (22.5%)	na	Exploration	na	na
Block 30/13c and 30/14	Flyndre	Maersk Oil (88.34%), Equinor (6.65%), Petoro (5%)	2017	Production	10,000	na
Block 30/13c and 30/14	Cawdor	Maersk Oil (60.6%)	2017	Development	5,000	na
Block 3/3	Orlando	Atlantic Petroleum (25%), Iona Energy (75%)	2017	Development	11,000	na
Ythan	Ythan	EnQuest (60%), Ithaca Energy (40%)	2015	Production	5,000	na
Block 9/3b, Licence P1078	Bentley	Xcite Energy (100%)	na	Appraisal	40,000	na
Block 110/12	Conwy	EOG Resources (100%)	2016	Production	20,000	na
Block 29/1a, 29/1b	Bittern	Dana Petroleum (32.9%), Shell (39.63%), Endeavour Energy (2.42%), ExxonMobil (25%)	2000	Production	60,000	0.7
Block 21/25a, 30a	Guillemot West	ExxonMobil (10%), Dana Petroleum (90%)	2000	Production	28,000	0.5
Licence P0021, Block 21/24a	Clapham	Dana Petroleum (100%)	2003	Production	15,000	na
Licence P0353, Block 21/23b	Pict	Dana Petroleum (100%)	2005	Production	10,000	na
Licence P0353, Block 21/23b	Saxon	Dana Petroleum (100%)	2007	Production	na	na
Licence P0128,	Anglia	RWE Dea (12.2%), First Oil	1991	Production	na	0.5

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Block 48/18b, 19b		Expro (32.8%), Dana Petroleum (25%), Ithaca Energy (30%)				
Licence P0456, Block 48/2a	Babbage	Bayerngas Norge (13%), Dana Petroleum (40%), Premier Oil (47%)	2010	Production	na	0.7
Licence P0224, P0225	Banff	Dana Petroleum (12.4%), CNR International (87.61%)	1999	Production	60,000	na
Block 29/2c	Kyle	Premier Oil (40%), Dana Petroleum (14.29%), CNR International (45.71%)	2001	Production	20,000	na
Block 30/3a	Blane	Repsol (18%), Faroe Petroleum (30.5%), JX Nippon Oil & Energy Corporation (13.9%), Dana Petroleum (12.5%)	2007	Production	17,000	na
Licence P0324, Block 13/22a	Captain	Dana Petroleum (15%), Chevron (85%)	1997	Upgrade/EOR	85,000	na
Block 43/19a	Cavendish	Dana Petroleum (50%), RWE Group (50%)	2007	Production		0.6
Block 22/2a	Chestnut	Centrica (82.2%), Dana Petroleum (17.8%)	2008	Production	14,000	na
Block 14/19	Claymore	Dana Petroleum (7.52%), Transworld Petroleum (17.7%)	1977	Production	75,000	na
Block 16/13a	Enoch	Aker BP (2%), CapeOmega (4.36%), Equinor (11.78%), Endeavour Energy (8%), Faroe Petroleum (13.86%), First Oil Expro (14%), Dana Petroleum (20.8%)	2007	Production	15,000	na
Block 20/2a & 20/3a	Ettrick	CNOOC (80%), Atlantic Petroleum (8%), Dana Petroleum (12%)	2009	Decommissioned	30,000	na
Licence P0073, Block 21/12a	Goosander	EnQuest (50%), Dana Petroleum (50%)	2006	Production	9,500	na
Licence P0351, Block 21/18a	Kittiwake	EnQuest (50%), Dana Petroleum (50%)	1990	Production	10,000	na
Block 21/19	Mallard	Dana Petroleum (50%), EnQuest (50%)	1998	Production	16,000	na
Block 210/24a	Hudson	TAQA (Abu Dhabi National Energy Company) (26.7%), Cieco (25.7%), Dana Petroleum (47.5%)	1993	Production	12,000	na
Licence P0686, Block 43/27a	Johnston	Dana Petroleum (49.9%), Premier Oil (50.11%)	na	Production	na	0.9

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Block 49/22a & 49/17	Victor	CalEnergy Resources (5%), RWE Group (10%), ExxonMobil (25%), ConocoPhillips (20%), Centrica (30%), Dana Petroleum (10%)	1984	Production	na	na
Block 21/19	Grouse	Dana Petroleum (50%), EnQuest (50%)	2008	Production	10,000	na
Block 21/19	Gadwall	Dana Petroleum (50%), EnQuest (50%)	2005	Production	6,000	na
Block 13/23a	Wester Ross	Atlantic Petroleum (20%), Dana Petroleum (45%)	na	Discovery	na	na
Block 21/17a	Wagtail	Dana Petroleum (50%), EnQuest (50%)	na	Discovery	na	na
Block 21/20f	Morgan	Dana Petroleum (35%)	na	Discovery	na	na
Licence P1726	Block 43/17a,18a	Government of United Kingdom	na	Suspended	na	na
Licence P1742, Block 47/10c & 48/6c	Blackadder	Hansa Hydrocarbons (23.08%), Parkmead Group (30.77%), Dyas (46.15%)	na	Discovery	na	na
Licence 1766, Block 13/22d	Licence 1766, Block 13/22d	Dana Petroleum (50%)	na	Exploration	na	na
Licence 1786, Block 21/12d	Licence 1786, Block 21/12d	Dana Petroleum (50%)	na	Exploration	na	na
Licence P.1330, Block 42/28d, Southern Gas Basin	Mongour, Tolmount	Dana Petroleum (50%), Premier Oil (50%)	2020	Discovery	na	2
Licence P1566, Block 47/4d, 47/5d	Pharos	Parkmead Group (30.77%), Dyas (23.08%), Hansa Hydrocarbons (46.16%)	na	Appraisal	na	na
Licence P1833	Block 204/14d	Government of UK	na	Suspended	na	na
Licence P1849	Block 214/5c, 214/9d, 214/10b	Government of UK	na	Suspended	na	na
Block 14/25a	Block 14/25a	Government of UK	na	Suspended	na	na
Block 16/13e	J1	Endeavour Energy (10%), Dyas (17.5%), Roc Oil (15%), Repsol (31.5%), Dana Petroleum (26%)	na	Appraisal	na	na
Licence P0028	Block 47/5c	Dana Petroleum (81.28%)	na	Exploration	na	na
Block 15/28b	Rubie	Endeavour Energy, Dana Petroleum (20%)	na	Development	na	na
Licence P1896	Block 42/27, 47/2c, 3i	Dana Petroleum (50%), Dyas (50%)	na	Exploration	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Block 13/23d	Liberator	Dana Petroleum (100%)	na	Discovery	na	na
Licence P.2014	Block 208/6 &7	Orsted A/S (60%), Dana Petroleum (40%)	na	Exploration	na	na
Licence P2173	GKA West	Dana Petroleum (50%), EnQuest (50%)	na	Discovery	na	na
Licence P2177	GKA East	Dana Petroleum (50%), EnQuest (50%)	na	Discovery	na	na
Licence P2180, Block 21/29c	GGA Scavaig	Dana Petroleum (100%)	na	Discovery	na	na
Licence P2053	Block 29/17, 29/18a, 29/22a, 29/23a	Repsol, Dana Petroleum (35%)	na	Exploration	na	na
Licence P.2044	Licence P.2044	CNOOC (25%), GDF Suez (25%), Dana Petroleum (15%), Orsted A/S (35%)	na	Exploration	na	na
Block 48/1e	Block 48/1e	Government of United Kingdom	na	Suspended	na	na
Licence P.2105	Block 42/28e	Dana Petroleum (50%), E.ON (50%)	na	Exploration	na	na
PEDL209	Laughton Prospect	Egdon Resources (50%), Park Exploration (28%), Stelinmatvic Industries (12%), Union Jack Oil (10%)	na	Exploration	na	na
Greater Kittiwake Area (GKA)	Eagle	EnQuest (100%)	na	Discovery	na	na
Licence P2013, Block 21/5c	Finlaggan	Zennor Petroleum (100%)	2021	Production	na	na
Licence P1588 (Block 30/1f), Licence P363 (Block 30/1c)	Vorlich	Ithaca Energy, BP	na	Appraisal	na	na
Licence P1823, Block 30/13b	Austen	Ithaca Energy (75%), Premier Oil (25%)	na	Appraisal	na	na
Licence P2248	Block 43/11	Cluff Natural Resources (100%)	na	Exploration	na	na
Block 205/22b, 205/23 and 205/24	Halifax	Hurricane Exploration (100%)	na	Discovery	na	na
Block 27/3, 27/4, 27/5, 27/9, 27/10, 28/1 & 28/6	Block 27/3, 27/4, 27/5, 27/9, 27/10, 28/1 & 28/6	North Sea Natural Resources (100%)	na	Agreement signed	na	na
Block 21/22 (Part), 21/26	Block 21/22 (Part), 21/26 (Part), 21/	The Steam Oil Production Company (100%)	na	Agreement signed	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
(Part), 21/27b (Part) & 21/28b (Part)	27b (Part) & 21/28b (Part)					
Block 16/7e	Block 16/7e	Taqa Bratani (100%)	na	Agreement signed	na	na
Block 16/1c & 16/2a	Block 16/1c & 16/2a	BP, Equinor	na	Agreement signed	na	na
Block 15/9 (Part), 15/10, 15/14, 15/15, 16/6b & 16/11a	Block 15/9 (Part), 15/10, 15/14, 15/15, 16/6b & 16/11a	BP, Equinor	na	Agreement signed	na	na
P2317, Block 14/13a, 14/14b, 14/15b	Bird	AziNor Catalyst (80%), Dyas (20%)	na	Agreement signed	na	na
P2316, Blocks 14/8, 14/9, 14/10, 14/13b, 14/14a, 14/15a, 15/11	Marshall	Dyas (20%), AziNor Catalyst (80%)	na	Agreement signed	na	na
Block 9/26 (Part)	Block 9/26 (Part)	BP, Equinor	na	Agreement signed	na	na
Block 9/17b (Part) & 9/22 (Part)	Block 9/17b (Part) & 9/22 (Part)	BP, Equinor	na	Agreement signed	na	na
Block 8/27, 8/28b, 15/2, 15/3, 15/7 & 15/8	Block 8/27, 8/28b, 15/2, 15/3, 15/7 & 15/8	BP, Equinor	na	Agreement signed	na	na
Block 3/16 (Part) & 3/17 (Part)	Block 3/16 (Part) & 3/17 (Part)	Nautical Petroleum (100%)	na	Agreement signed	na	na
Block 3/7c (Part), 3/8c (Part) & 3/12 (Part)	Block 3/7c (Part), 3/8c (Part) & 3/12 (Part)	Decipher Energy (100%)	na	Agreement signed	na	na
Block 3/6 (Part)	Block 3/6 (Part)	Alpha Petroleum (100%)	na	Agreement signed	na	na
Block 2/5b	Block 2/5b	Zennor Petroleum (100%)	na	Agreement signed	na	na
Block 29/22b, 29/23b, 29/27, 29/28	Block 29/22b, 29/23b, 29/27, 29/28	Simwell Resources (100%)	na	Agreement signed	na	na
Block 35/24, 35/28, 35/29, 35/30, 36/21, 36/26, 36/27, 36/28, 36/29 & 42/2a	Block 35/24, 35/28, 35/29, 35/30, 36/21, 36/26, 36/27, 36/28, 36/29 & 42/2a	Centrica (100%)	na	Agreement signed	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Block 36/15 (Part), 36/20, 37/11 (Part) & 37/16	Block 36/15 (Part), 36/20, 37/11 (Part) & 37/16	Horizon Energy Partners, Ardent Oil	na	Agreement signed	na	na
Block 36/24, 36/25, 37/21, 37/22 (Split), 37/23 (Split), 37/28b & 37/29b	Block 36/24, 36/25, 37/21, 37/22 (Split), 37/23 (Split), 37/28b & 37/29b	Horizon Energy Partners, Simwell Resources, Ardent Oil	na	Agreement signed	na	na
Block 37/17, 37/18, 37/19, 37/22 (Split), 37/23 (Split) & 37/24	Block 37/17, 37/18, 37/19, 37/22 (Split), 37/23 (Split) & 37/24	Chrysaor (100%)	na	Agreement signed	na	na
Block 38/27, 38/28, 44/2 & 44/3 (Part)	Block 38/27, 38/28, 44/2 & 44/3 (Part)	Draupner Energy (100%)	na	Agreement signed	na	na
Block 41/3, 41/4 & 41/9	Block 41/3, 41/4 & 41/9	Simwell Resources (100%)	na	Agreement signed	na	na
Block 132/3b, 132/4, 132/5 (Part), 132/9, 132/10, 132/13b, 132/14, 132/15, 132/18, 132/19, 132/20 (Part), 133/11 (Part), 142/28 (Part) & 142/29 (Part)	Block 132/3b, 132/4, 132/5 (Part), 132/9, 132/10, 132/13b, 132/14, 132/15, 132/18, 132/19, 132/20 (Part), 133/11 (Part), 142/28 (Part) & 142/29 (Part)	Equinor, ExxonMobil	na	Agreement signed	na	na
Block 202/2, 202/3, 204/17, 204/21, 204/22b, 204/26, 204/27, 204/28a, 204/28b & 204/29b	Block 202/2, 202/3, 204/17, 204/21, 204/22b, 204/26, 204/27, 204/28a, 204/28b & 204/29b	Shell (100%)	na	Agreement signed	na	na
Block 204/18 (Part), 204/19c & 204/20c	Block 204/18 (Part), 204/19c & 204/20c	BP, Shell	na	Agreement signed	na	na
Block 210/4a, 210/5a, 210/5b, 210/9a & 210/10	Block 210/4a, 210/5a, 210/5b, 210/9a & 210/10	Bayerngas Norge, BP	na	Agreement signed	na	na
Morecambe Bay Project	North Morecambe, South Morecambe, Rhyl, Millom,	ConocoPhillips, Centrica	1985	Production	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
	Dalton, Rivers and Bain					
P1830	P1830	Siccar Point Energy (75%), Orsted A/S (25%)	na	Exploration	na	na
Block 204/25a	Amos	Siccar Point Energy (35.3%), Shell (64.7%)	na	Discovery	na	na
Tobermory and Bunnehaven	Tobermory and Bunnehaven	Siccar Point Energy (17.5%), Orsted A/S (32.5%), TotalEnergies (30%), SSE (20%)	na	Discovery	na	na
P1854, P1935	P1854, P1935	Siccar Point Energy (100%)	na	Exploration	na	na
P2138	Benbecula	Orsted A/S (10%), Equinor (30%), Siccar Point Energy (60%)	na	Discovery	na	na
P2139, P2307	P2139, P2307	Siccar Point Energy (100%)	na	Exploration	na	na
P2062 South	P2062 South	BP (30%), Nexen (45%), Siccar Point Energy (25%)	na	Exploration	na	na
P2170	Verbier	Cieco (12%), Jersey Oil and Gas (18%), Equinor (70%)	na	Discovery	na	na
P2097, P2275	Jock Scott	Equinor (75%), BP (25%)	na	Exploration	na	na
P2163	P2163	BP (40%)	na	Exploration	na	na
P2147	P2147	BP (40%)	na	Exploration	na	na
P2062	Craster	CNOOC, BP (30%)	na	Exploration	na	na
Blocks 48/22b & 48/23a (Blythe Hub)	Blythe, Elgood	Independent Oil and Gas (100%)	2019	Appraisal	na	na
Block 49/21a, 49/21d, 48/25b, 49/21c	Vulcan North West, Vulcan East, Vulcan South (Vulcan Satellites)	Independent Oil and Gas (100%)	2019	Discovery	na	na
Block 48/23c & 48/24b (P2085)	Harvey	Independent Oil and Gas (100%)	na	Discovery	na	na
Block 9/21a	Skipper	Independent Oil and Gas (100%)	na	Appraisal	na	na
Block 211/8	Block 211/8	Shell	na	Agreement signed	na	na
Block 211/19a	Block 211/19a	EnQuest	na	Agreement signed	na	
Block 9/18e (split)	Block 9/18e	Apache Corporation	na	Agreement signed	na	na
Block 9/18e (split)	Block 9/18e	Maersk	na	Agreement signed	na	na
Block 10/1b	Block 10/1b	Equinor	na	Agreement	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
				signed		
Block 12/28	Block 12/28	Jetex Petroleum	na	Agreement signed	na	na
Block 16/18c	Block 16/18c	Apache Corporation	na	Agreement signed	na	na
Block 21/30e	Block 21/30e	Actis Oil and Gas	na	Agreement signed	na	na
Block 43/21b	Block 43/21b	Speedwell Energy	na	Agreement signed	na	na
Block 44/16b	Block 44/16b	Speedwell Energy	na	Agreement signed	na	na
Block 48/1d	Block 48/1d	BP	na	Agreement signed	na	na
Block 48/25a	Block 48/25a	Independent Oil & Gas	na	Agreement signed	na	na
P1989, Block 14/11a, 14/12a, 14/16a	Partridge	AziNor Catalyst (100%)	na	Exploration	na	na
P1763, Block 9/9d & 9/14a	Agar/Plantain	AziNor Catalyst (50%), Apache Corporation (50%)	na	Discovery	na	na
P2150, Blocks 9/16 & 9/11e	Irresistible	AziNor Catalyst (100%)	na	Discovery	na	na
P2162, Block 15/29e	Five Star	AziNor Catalyst (100%)	na	Exploration	na	na
P2165, Block 16/8c	Boaz	AziNor Catalyst (100%)	na	Exploration	na	na
P2169, Block 16/24c	Burnt Island	AziNor Catalyst (100%)	na	Exploration	na	na
P2172, Blocks 20/8c & 9a	Inner Pear	AziNor Catalyst (100%)	na	Discovery	na	na
P2179, Block 21/25c	Hinson	AziNor Catalyst (49%), MOL Group (51%)	na	Exploration	na	na
P2243, Block 14/17a	Oberon	AziNor Catalyst (50%), Zennor Petroleum (50%)	na	Exploration	na	na
P2278, Blocks 13/16b and 13/17	Churchward	AziNor Catalyst (100%)	na	Exploration	na	na
P2280, Blocks 15/25d and 15/30b	Five Star Upside	AziNor Catalyst (100%)	na	Exploration	na	na
Block 16/23 (Andrew Area)	Arundel	BP	2017	Production	9,000	na
Block 16/28 (Andrew Area)	Cyrus	BP	1990	Production	na	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
Block 16/28 (Andrew Area)	Farragon	CNOOC (20%), Eni (30%), BP (50%)	2005	Production	18,000	na
J Block	Jasmine	Shell (30.5%), ConocoPhillips (36.5%), Eni (33%)	2013	Production	140,000	na
P1575: Block 9/2b & 9/2c	Kraken	Cairn Energy (29.5%), EnQuest (70.5%)	2017	Production	na	na
Block 206/1a, 205/4b and 205/5a	Laggan, Tormore	SSE (20%), TotalEnergies (60%), Orsted A/S (20%)	2016	Production	90,000	na
East Rochelle (Block 15/27), West Rochelle (Blocks 15/26b, 15/26c)	East Rochelle, West Rochelle	CNOOC (41%), Endeavour Energy (44%), Premier Oil (15%)	2013	Production	10,000	na
Block 22/30b	Shearwater	Atlantic Richfield Company (27.5%), Shell (28%), ExxonMobil (44.5%)	2000	Upgrade/EOR	90,000	4.1
Block 42/12a and 42/13a	Breagh	Ineos (70%), Sterling Energy (30%)	2013	Production	na	1.1
Block 16/26	Alba	Centrica (12.65%), EnQuest (8%), Chevron (23.37%), Endeavour Energy (25.68%), Equinor (17%), Mitsui (13.3%)	1994	Upgrade/EOR	390,000	na
Licence P.986 (Block 19/10 and 20/6) and Licence P.928(S) (Block 19/5a and 20/1S)	Buzzard	Oranje Nassau (0.46%), Dyas (4.7%), Chrysaor (21.73%), CNOOC (43.21%), Suncor (29.89%)	2007	Production	220,000	na
Caister Murdoch System: Block 44/22a, 44/23a	Caister, Boulton, Munro, Murdoch, Kelvin, Katy (Harrison), CMS III	ConocoPhillips, Tullow Oil, Engie	1993	Production	na	na
Eastern Trough Area Project (ETAP)	Marnock, Mungo, Machar, Monan, Mirren, Madoes, Heron, Egret, Skua	BP, Eni, Shell, ExxonMobil, Nippon Oil, TotalEnergies	1998	Production	210,000	3.6
Elgin-Franklin	Elgin, Franklin, West Franklin and Glenelg	Shell (14.1%), Eni (21.9%), Premier Oil (5.2%), Dyas (2.2%), Summit Petroleum (2.2%), TotalEnergies (46.2%), ExxonMobil (4.4%), Chevron (3.9%)	2001	Production	220,000	na
Block 204/19a,	Foinaven, Foinaven	Marathon Oil, BP, Faroe	1997	Production	130,000	1.2

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
204/24a and 204/25b	East	Petroleum				
Penguins	Penguins	ExxonMobil (50%), Shell (50%)		Production	na	na
Forties Complex, Block 21/10	Forties	ExxonMobil (2.61%), Apache Corporation (97.14%), Shell (0.25%)	1975	Production	520,000	na
Block 21/25, 21/30, 22/21 and 22/26a	Gannet	ExxonMobil (50%), Shell (50%)	na	Production	na	na
Block 29/4e	Capercaillie	BP (100%)	na	Discovery	na	na
Block 206/9b	Achmelvich	Chevron (19.4%), Shell (28%), BP (52.6%)	na	Discovery	na	na
Block 14/29a	Goldeneye	Repsol (7.5%), Shell (49%), ExxonMobil (39%), Centrica (4.5%)	2004	Decommissioned	10,000	1.1
Block 9/23	Harding	TAQA (Abu Dhabi National Energy Company) (70%), Maersk Oil (30%)	1996	Production	20,000	na
Block 211/12a	Magnus	BP (100%)	1983	Upgrade/EOR	156,000	0.6
Quad 204	Schiehallion	BP (33%), Siccar Point Energy (12%), Shell (55%)	1998	Upgrade/EOR	117,000	na
Block 9/18a	Garten	Apache Corporation (100%)	na	Discovery	na	na
Licence P614, Block 47/14b	Juliet	Engie (51.56%), First Oil Expro (29.44%), Hansa Hydrocarbons (19%)	2014	Production	na	0.8
Block 213/26 and 213/27	Rosebank	Siccar Point Energy (20%), Suncor (30%), Chevron (40%), Orsted A/S (10%)	na	Appraisal	100,000	0.8
Block 44/12a and 44/11a	Cygnus	Engie (38.75%), Bayerngas Norge (12.5%), Centrica (48.75%)	2016	Production	na	2.5
Block 29/3c	Fram	ExxonMobil (68%), Shell (32%)	2018	Development	35,000	na
Block 9/24b and 9/29a	Devenick	TAQA (Abu Dhabi National Energy Company) (88.7%), RWE Group (11.3%)	2012	Production	na	1
Block 22/17, 22/18, 22/22, 22/23 [Montrose Area Redevelopment (MAR)]	Montrose, Arbroath, Brechin, Arkwright, Carnoustie, Wood, Cayley, Shaw, Godwin	Marubeni Corporation, China Petroleum & Chemical Corporation (Sinopec), Repsol	1976	Upgrade/EOR	40,000	na
Block 15/20a,	Balloch	Maersk Oil (100%)	2013	Production	8,000	na

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
15/20b						
Block 23/11, 23/16b and 23/16c	Arran (Barbara-Phyllis)	Dana Petroleum	2021	Production	na	na
Licence P077, Block 21/28a	Fyne	Government of United Kingdom	na	Suspended	na	na
Licence P.103, Block 21/05a	Enochdhu	Chevron (50%), ConocoPhillips (50%)	2015	Production	10,000	na
Western Isles Development (WID), Block 210/24a	Barra (Formerly Melville), Harris (Formerly East Rinnes)	Cieco (23%), Dana Petroleum (77%)	2017	Production	44,000	na
Block 3/28a	Bressay	Equinor (81.6%), Shell (18.4%)	na	Appraisal	65,000	na
Elgin-Franklin, Block 22/30b, 22/30c, 29/5b	Elgin	Shell (14.1%), Eni (21.9%), Premier Oil (5.2%), Summit Petroleum (2.2%), TotalEnergies (46.2%), Chevron (3.9%), ExxonMobil (4.4%), Dyas (2.2%)	2001	Production	140,000	5.2
Elgin-Franklin, Block 29/5b	Franklin	Shell (14.1%), Eni (21.9%), Premier Oil (5.2%), Summit Petroleum (2.2%), TotalEnergies (46.2%), Chevron (3.9%), ExxonMobil (4.4%), Dyas (2.2%)	2001	Production	41,000	2.7
Elgin-Franklin, Block 29/4d, 29/5b	West Franklin	Shell (14.1%), Premier Oil (5.2%), Eni (21.9%), Summit Petroleum (2.2%), TotalEnergies (46.2%), Chevron (3.9%), ExxonMobil (4.4%), Dyas (2.2%)	2007	Production	45,000	na
Greater Alwyn: Block 3/4A, 3/9A and 3/10B	Alwyn North	TotalEnergies (100%)	1987	Production	140,000	na
Greater Alwyn: Block 3/14A, 3/13A, 3/8A, 3/9B, 3/14B	Dunbar	TotalEnergies (100%)	1994	Production	70,000	na
Greater Alwyn: Block 3/15, 3/14A	Ellon	TotalEnergies (100%)	1994	Production	17,000	na
Greater Alwyn: Block 3/14a, 3/	Grant	TotalEnergies (100%)	1998	Production	na	0.6

Name	Field Name	Companies	Completion Date	Status Select	Est. Peak Oil/Liquids Range (b/d)	Est. Peak Gas Output (bcm)
14d						
Greater Alwyn: Block 3/19a, 3/20a, 3/24a, 3/25a, 3/18, 3/19b, 3/24c	Nuggets	TotalEnergies (100%)	2001	Production	36,000	na
Block 13/28a & 13/29a	Ross	China Petroleum & Chemical Corporation (Sinopec), Repsol, Idemitsu Petroleum (30.82%)	1999	Production	40,000	na
Block 13/24, 13/29b	Blake, Blake Flank	Idemitsu Kosan (30.82%), China Petroleum & Chemical Corporation (Sinopec), Repsol	2001	Production	85,000	na
Block 16/23 (Andrew Area)	Kinnoull	JX Nippon Oil & Energy Corporation (22.94%), BP (77.06%)	2014	Production	50,000	na
Block 2/10b, 2/15a and 3/11b	Cheviot (formerly Emerald)	Alpha Petroleum (100%)	na	Upgrade/EOR	25,000	0.5
Block 15/29A	Alder	Chevron (73.68%), ConocoPhillips (26.32%)	2016	Production	14,000	1.1

na = not available/applicable. Source: BMI

Upstream Oil Production

Key View: *In the short term, we still expect a weak return of oil production growth thanks to new production from the Penguin, Seagull, and Talbot fields. A mid-term boost to the UK's mid-term oil production prospects also came from the recent North Sea Transition Authority approval of the Rosebank oil project, which stands as the largest untapped oil reserve in the country. However, the ongoing court case against Rosebank poses a significant risk that could lead to delays and further uncertainty. New Labour government proposed policy directions could catalyse divestment from the UK upstream sector while warding off potential new buyers of legacy assets, creating a double negative impact on the UK's long-term hydrocarbons production outlook and accelerating the ageing basin's decline. Proposed higher and longer Energy Profit Levy taxes, and the scrapping of investment capital allowances will likely significantly reduce investments. We therefore believe the new government creates long-term downside risks to our already bearish oil production outlook. The long-term trend for UK oil production is therefore increasingly bearish, with highly mature fields, a lack of investment, and insufficient greenfield developments seeing production continue on a general downward trend.*

Latest Updates

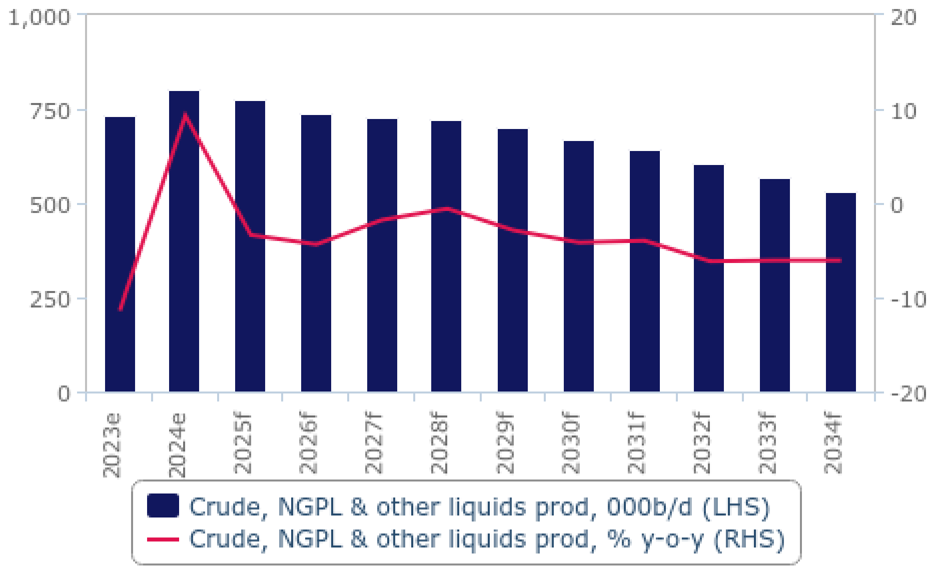
- On January 30, it was announced that the court has ruled that consent for the Rosebank and Jackdaw oil and gas fields in Scotland was granted unlawfully, requiring a new environmental impact assessment that includes downstream emissions, with fresh approval from the UK government needed before production can begin, amidst ongoing debates on climate implications and energy security. This development creates significant downside risks to our oil production outlook potentially creating project delays.
- On December 5, it was announced that Shell U.K. Limited and Equinor UK Ltd announced plans to merge their UK offshore oil and gas assets to form the UK's largest independent oil producer, equally owned by both companies, with expected completion by the end of 2025, aiming to boost production to 200,000-220,000boe/d within five years from over 140,000boe/d in 2025.
- In August 2024, Sevan SSP completed the installation of a circular FPSO for Shell UK's Penguins field redevelopment in the North Sea, with a Sevan 400 design platform featuring a processing capacity of 45,000boe/d and storage of 400,000bbl. It was built in China and commissioned in Norway under a partnership between Shell and NEO Energy.
- Recent years have seen heavy declines in the UK's oil production, which on average declined by around 11.0% y-o-y from 2020-2023, with crude and condensates production falling from 1.0mn b/d in 2019 to an estimated 646,000b/d in 2023. We see these declines being stemmed in the short term. We forecast the UK's crude production to come in slightly higher in 2024 and 2025 to 801,700b/d and 774,800b/d respectively, due to the ramp up of production at the new Seagull fields, the Penguins redevelopment field and the Talbot redevelopment project.
- Rosebank has faced legal challenges from environmental groups this quarter, and the confirmed EPL increase presents downside risks to our mid-term oil production outlook, which heavily relies on Rosebank. While we believe the initial USD3.8bn first phase will likely proceed in 2027, there is a risk that the planned second phase could be reconsidered if the EPL increases are deemed unfavorable for investors. T
- We note strong long-term downside risks to our oil production forecasts in the context of the recent Labour victory at the July 2024 general elections. The new UK Labour government has proposed in July 2024 a series of additional changes to the fiscal regime covering production in the UK and the UK Continental Shelf. They plan to raise the Energy Profits Levy by 3% and increasing taxes to 78%, on par with Norway's marginal tax rate. The end-date would also be pushed back to 2030. Moreover, there are plans to scrap the levy's 29% investment allowance, which allowed companies to offset tax from capital that is re-invested. This would therefore likely strongly de-incentivise new investments.
- Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors. On average, UK oil and gas projects are relatively costly and will become more so under a Labour government. There are wide-ranging opportunities for investment abroad, both amongst legacy producers – such as North America, Brazil and the GCC – and in new and emerging plays – such as Guyana and, potentially, east and south-western Africa. Compared to this, a compelling investment case for the UK becomes increasingly difficult to make.

- Proposed Labour policy will likely catalyse divestment from the UK upstream sector while warding off potential new buyers of legacy assets, creating a double negative impact on the UK's long-term hydrocarbons production outlook. We therefore believe the new government will result in long-term downside risks to our already bearish oil production outlook. We have not yet downgraded our forecasts, waiting for final policies to be decided/implemented, in order to gage company reactions and possible project delays/cancellations. At the time of writing, we forecast the long-term outlook to remain on a general downtrend, despite the short-term boost from individual developments over the coming years. By 2034, we forecast oil production levels of 533,000b/d, down from expected levels of 801,000b/d in 2024. Risks are now increasingly tilted to the downside given likely Labour policies on the sector.
- According to 2024 updates, BP is working on plans for Phase 3 of the Clair Ridge project West of the Shetlands. The project would target Clair South, one of the UK's largest remaining undeveloped offshore accumulations.
- In early 2024, Jersey Oil & Gas submitted the Buchan redevelopment project's environmental statement to the UK regulator. Located 115km offshore Aberdeen, this is the UK's third-largest undeveloped offshore oil resource. The environmental approval would be for a project with an electrification-ready floating production, storage and offloading vessel. In February 2024, Serica Energy purchased a 30.0% non-operated stake from Jersey Oil & Gas in the licences containing the Buchan field and the neighbouring J2 and Verbier discoveries.

Structural Trends

Oil Industry Faces Decline Amid Tax Changes

UK - Oil Production Forecast (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The UK oil industry is very mature, and decline rates over the past years have been heavy, with crude oil and condensates production declining at an average 3.0% y-o-y over the 2013-2023 period, despite the temporary boost in output over 2015-2019. The production boost over 2015-2019 was incentivised by the high oil price environment at the time and field allowances and tax incentives introduced in 2012 by the government which boosted project approvals over 2012-2013 and led to these coming online over the 2016-2019 period.

However, production has since returned to a strong downtrend - the result of limited exploration and development activity, weak project sanctioning and a changeable policy and fiscal environment. Recent production fell from a high of 1.03mn b/d of crude oil and condensates in 2019 to an estimated 0.65mn b/d in 2023. The extent of the decline is even more telling when considering production was at levels of about 2.7mn b/d in 1999.

2023 saw a particularly strong decline rate of 11.4% y-o-y decline in output. The industry was particularly impacted in 2023 by a 35.0% increase in headline taxation under the 2022 Energy Profits Levy (extended by new Labour government mid-2024 to 2030, and increased rate of another 3%). The UK business environment has been particularly variable over the past years, as have oil prices, leading several companies to decide against investing further in some fields' redevelopment, rather allowing for a progressive decline in production at mature fields, or what we can call a 'managed decline' leading to continued decline rates.

A Significant Fiscal Upheaval

	Ring-Fence Corporation Tax*	Supplementary Charge	Petroleum Revenue Tax**	Energy Profits Levy	Total Marginal Tax Rates
Description	Tax on ring-fenced profits.	Additional tax on profit introduced in 2011 in context of high oil prices.	Field-based tax charged on profits arising from oil and gas production from field given development consent before 1993.	na	na
Previous fiscal regime	30%	20%	35%	na	65% on profits from PRT-paying fields
					50% for other fields
New fiscal regime	30%	10%	0%	35% (set to be 38% from November 2024 onwards under new Labour government manifesto).	75% for all fields (78% after proposed new rate increase end-2024).

*Note: *Profits from oil and gas exploration and production are subject to the ring-fence rate; refining and marketing subject to non-ring-fence rate. **For fields that received development consent before 16 March 1993; na = not applicable/available. Source: BMI*

The introduction of the 35.0% windfall tax raised the tax burden on UK oil & gas producers to 75.0%, which is one of the highest in the world. However, the greatest impact has been on sentiment. In order to try to minimise the effect of the tax on investment, a new investment allowance has been introduced. Under the current investment allowance, total tax relief is equivalent to GBP46 for every GBP100 spent; however, the new allowance will enable GBP91 to be relieved for every GBP100 spent. The actual tax generated could thus vary wildly depending on the action that companies take in response with regard to UK investments. The outcome will likely be negative, based on concerns over the implementation of additional future windfall taxes and the sharp change to fiscal terms to an industry that is cyclical in nature, rather than as a result of higher taxes themselves.

Our Medium-Term Oil Production Outlook Hinges On Rosebank

The recent court ruling against the Rosebank project significantly impacts its development outlook, highlighting growing uncertainties and challenges for upstream operators in the UK. Located 130 kilometers northwest of Shetland, the Rosebank field holds approximately 300mn bbl of untapped oil reserves. Lead operator Equinor now faces the task of addressing the legal and environmental challenges resulting from this decision.

Greenpeace and Uplift argued that regulators unlawfully ignored the emissions impact of burning the extracted oil and gas. Consequently, operators must resubmit environmental assessments before drilling can proceed. This ruling aligns with a prior Supreme Court decision requiring consideration of the total environmental impact of new projects. In August, the UK government's choice not to contest any Rosebank cases underscored a policy shift.

Further complicating matters is the UK government's October 2024 decision to increase the windfall tax on North Sea Oil and Gas Producers from 35% to 38% and extend the levy by one year, raising the headline tax rate to 78%, comparable to Norway. This fiscal pressure adds to the challenges facing the industry.

Our medium-term oil production outlook for the UK is closely tied to the Rosebank field's development. The court ruling introduces significant downside risks to our forecast, as the field could have contributed 70,000 b/d of oil, or 8% of the UK's average output between 2026 and 2030. The ruling is likely to delay the project, and potential amendments to the EPL may discourage future investments.

Initially, the project was planned in two phases, with a USD3.8bn first phase likely to proceed within our forecast period. However, the second phase now faces uncertainty and might be reconsidered due to the court ruling and fiscal changes. Philippe Francios Mathieu of Equinor has expressed concerns about the impact of fiscal regime changes on the project's viability.

Equinor's schedule included subsea installation from 2024 to 2026, with drilling from 2025 to Q3 2026. The Floating Production Storage and Offloading vessel (FPSO) was expected to arrive in Q2 2026 for hook-up and commissioning, with first oil anticipated by Q4 2026 and peak production of 70,000 b/d starting in 2027. This timeline is now subject to reassessment due to the ruling. The initial phase involved drilling production and water injection wells, with infrastructure developments connecting to a redeployed FPSO, exporting gas via a new pipeline, and offloading oil using tankers. The court ruling and EPL increase raise the possibility of delays or a reassessment of the project's second phase, as Equinor considers the investment climate in light of these changes.

Long-Term Oil Production Outlook Further Impacted By 2024 Labour Win

As noted earlier in this report *(see 'Exploration' section for further details)*, the outlook for exploration and production in the mature UK market has further worsened this quarter in the context of the recent Labour victory at the July 2024 general elections. The new UK Labour government has proposed in July 2024 a series of additional changes to the fiscal regime covering production in the UK and the UK Continental Shelf. Notably, they plan to raise the Energy Profits Levy by 3% and increasing taxes to 78%, on par with Norway's marginal tax rate. The level of government take is already among the highest in the world and arguably at odds with the country's mature asset base and declining output. In addition, the manifesto had also called to end licensing for the exploration of new oil and gas fields. Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-running declines in UK exploration and production.

UK-focused players are already voicing concerns that under Labour's new fiscal regime the capital costs of new projects may be impossible to recoup. While the new policies will align the UK with Norway's marginal tax rate, it should be noted that Norway also offers tax rebates set at 100% of a company's capital expenditures, which Labour seemingly will not. This dramatically alters the calculus for investment. Future exploration has also posed upside risk to our outlook, but Labour's licensing ban will have put paid to this. Admittedly, mature acreage tends not to yield major new discoveries. However, production can often be supported via near-field exploration and satellite developments tied into existing infrastructure. The ban may curb the economic lifespan of existing reservoirs and lead to the earlier decommissioning of existing platforms and pipelines.

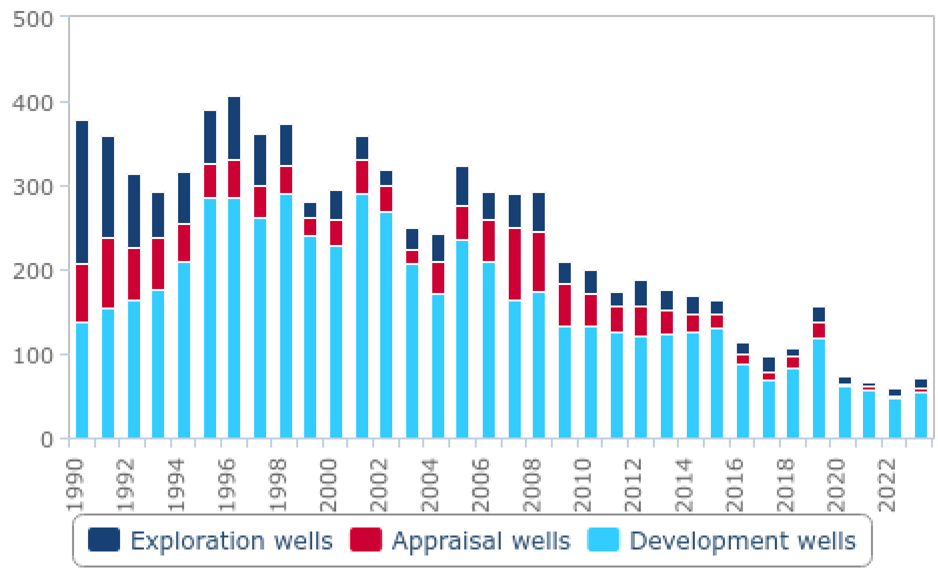
The UK was already struggling to compete for capital on a global scale. Against the backdrop of the broader energy transition, the capital allocation process is highly competitive, and companies are keeping a laser-like focus on commercial breakevens. On average, UK O&G projects are relatively costly and will become more so under a Labour government. There are wide-ranging opportunities for investment abroad, both amongst legacy producers – such as North America, Brazil and the GCC – and in new and emerging plays – such as Guyana and, potentially, east and south-western Africa. Compared to this, a compelling investment case for the UK becomes increasingly difficult to make.

Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will therefore likely deter investors:

- Jersey Oil and Gas, Serica Energy and Neo Energy had previously announced a delay to their Buchan project and explicitly linked the delay to the election. Should the manifesto promises be applied, investment on this key long-term project will likely be reconsidered.
- In August 2024, Equinor said it would reconsider investing in Britain if the Labour government changes the industry's tax regime. This is crucial given it is responsible for the development of the key Rosebank oil field in the Shetlands along with Ithaca Energy. This is the largest upcoming oil project in the UK. While the USD3.8bn first phase will likely continue to go forward, a planned second phase of development could be cancelled or reconsidered.
- Ithaca and Harbour Energy have also stated they plan on increasing their focus oversees. Harbour is a key oil producer in the UK, and Ithaca operates the Cambo oil project, which remains the second largest undeveloped oil and gas discovery in the North Sea. Labour had previously stated it would not greenlight the project, although this remains to be seen in practice (project still needs to demand and obtain a development licence).
- Ineos Energy recently said it intends to prioritise expansion in the US and Denmark rather than the UK due to the difficult fiscal context.
- Several other projects are also reportedly at risk, including Glendronach and Avalon.

UK Drilling In Strong Decline, Compromising Long-Term Production

Offshore UKCS Wellbores Spudded By Well Type (1990-2022)



Source: North Sea Transition Authority, BMI

Outlook

In the short term, we expect some limited production growth over 2024 and 2025 thanks to the ramping up of production at the Seagulls field which came online end-2023, and the coming online of the Penguins field later in 2024/early 2025.

However, the long-term outlook for the UK's oil production is mostly bearish, after years of heavy declines and lack of sufficient investment/developments to durably reverse the production decline over the long term. For example, the NSTA expects for its baseline assumptions for 60 development wells to be drilled per year in order to slow the ongoing decline in production (not even considering a reversal in production decline). However, the past four years have seen development wells drilling levels of 62, 56, 47 and 54 in 2020, 2021, 2022 and 2023 respectively. This shows that ongoing development works are insufficient to significantly reverse the outlook at the time of writing.

As seen earlier, Labour policy will likely catalyse divestment from the UK upstream sector while warding off potential new buyers of legacy assets, creating a double negative impact on the UK's long-term hydrocarbons production outlook. We therefore believe the new government will result in long-term downside risks to our already bearish oil production outlook. We have not yet downgraded our forecasts, waiting for final policies to be decided/implemented, in order to gage company reactions and possible project delays/cancellations. At the time of writing, we forecast the long-term outlook to remain on a general downtrend, despite the short-term boost from individual developments over the coming years. By 2034, we forecast oil production levels of 533,000b/d, down from estimated levels of 801,700b/d in 2024. Risks are now increasingly tilted to the downside given likely Labour policies on the sector.

The North Sea is a mature region and faces increasing challenges that threaten its long-term production potential. The long-term outlook remains bearish, and this for several reasons:

- **Relatively High-Cost Environment:** The North Sea remains a high-cost environment relative to its global peers. Shortages of key equipment, infrastructure in need of repair, insufficiently skilled oil and gas engineers, and cost escalation in the supply chain on a relative basis continue to be more predominant than in comparable basins. This disincentivises new exploration and development projects in the region.
- **Smaller Size Of Remaining Opportunities:** The UK is a mature basin by international standards. While earlier production came from large fields, much of the remaining resources and new discoveries are small in size. Increasingly, the small size of these discoveries does not justify stand-alone development.
- **Chronically Low Exploratory Drilling Levels:** Symptomatic of the previous two problems, exploration activity has been very weak over the past years, which has placed increased strain on the UK's long-term production. Smaller near-field and stranded asset tiebacks will help to mitigate against some of the declines seen in the wider capacity. However, it will be unable to fully prevent a fall in production. Exploratory drilling, which is instrumental in adding reserves and production growth, has fallen considerably in the UK in the past years. Between 2013 to 2019, the number of exploratory wells drilled per year averaged 12, while only seven wells were drilled in 2020, five in 2021, seven in 2022 and 12 in 2023.
- **Introduction Of Climate Compatibility Checkpoint:** In 2020, the UK paused licensing rounds to carry out a review of the licensing process and to ensure that future licensing rounds were compatible with the UK's 2050 net-zero pledge. In March 2021, the UK announced the North Sea Transition Deal, which would include the introduction of a 'Climate Compatibility Checkpoint' for future licensing rounds. In theory, the checkpoint would balance the need for future licences awarded to be aligned with net-zero emissions by 2050 and ensuring the UK's diverse energy supply. The most recently launched UK 33rd offshore licensing round was approved by the Climate Compatibility Checkpoint in September 2022. The checkpoint opened the door for future legal challenges on the decision-making process to award licences. It also posed downside risks to the UK upstream and increases costs.
- **Policy/Fiscal Environment Uncertainty:** This has been a particular problem over the past years, and is not favourable for large-scale investments towards maintaining oil production. The changeable policy environment does not provide certainty required for investments. Most illustrative of this over recent quarters has been the Energy Profits Levy windfall tax (*see above*), in addition to the weakening oil prices, which is not encouraging of future investments. The new Labour government as of 2024 has further increased the EPL tax rate from 35% to 38%, and pushed back the end date by another year, resulting in even more

concerns over the high taxation rate and the unstable nature of fiscal terms.

- **Renewable Energy Transition:** On a more general long-term structural level, the progressive transitioning toward renewables energy sources is leading to a progressive decrease in investment in fossil fuel extraction productions.

Our current long-term forecasts assume strong decline rates at existing producing fields, and integrates the following major developments with the forecast (*see below*). The mid-term outlook has recently slightly improved thanks to the agreement reached to develop the major Rosebank oil field. Major oil projects which have been approved and will contributed to UK oil production over the forecast period include:

- **Talbot Field**: Operated by Harbour Energy, this involved a thee well programme subsea tie-back to the Judy platform, with first oil expected late 2024.
- **Penguins Field:** This is the redevelopment of a hub that once served the giant Brent Charlie platform. A new FPSO was installed mid-2024, and first production at the oil and gas field is expected in H224 or early 2025. Shell also intends to take associated gas and export it through a new pipeline to the St Fergus terminal. The redevelopment is expected to unlock some 80mn barrels of oil that otherwise would have been left stranded as Brent Charlie shut down. Peak output is expected at 45,000boe/d at peak.
- **Murlach Redevelopmen**t: In late 2023, the UK government approved the Murlach oil and gas field redevelopment project, headed by BP. The redevelopment will recover around 26.0mn bbls of oil and 602.0mcm of gas. It will consist of two production wells and a subsea tieback to the Eastern Trough Area Projects installations. Peak production would be of 20,000b/d of oil and 0.2bcm of associated gas per year.
- **Rosebank Oil Field:** A major heavy oil field located West of the Shetlands which was approved in September 2023. It stands as stands as the largest untapped oil reserve in the country. It is operated by Equinor, with partners Suncor Energy and Siccar Point Energy. Production at the field is slated to begin in late 2026 or early 2027, with the bulk of oil extracted in the first two years (around 70,000b/d), after which output will plateau.
- **Cambo Oil Field**: Located northwest of the Shetland islands, it is operated by Ithaca Energy. It received approval in 2023 and will provide a significant boost to output given the field has an estimated 800mn barrels of oil. Development is planned in two phases, with production to start in 2028 and peak output expected in 2032. Peak production is expected at 50,000b/d of oil, and 0.3bcm of gas annually.

That being said, there is some upside risks to these forecasts from the following projects, which some will likely proceed to FID over the coming quarters and years. These include:

- **Clair Ridge Three Extension:** This project is an extension of the Clair oil field, also located West of the Shetlands. BP operated the project, along with partners Shell, Chevron and ConocoPhillips. The aim is to extend field life and boost output at the field. Production began in 2018, and the aim is to extend productive life of the field into the 2050s. According to media reports, BP is aiming to make an FID on its Clair Phase Three project in 2024. The company is considering developing the field through a bridge-linked platform that would be tied it to the current Clair Ridge facility. Alternatively, it is considering the development of an all-subsea development platform. Projected recovery rates from the project are estimated to be in the region of 292mn boe.
- **Buchan Redevelopment:** Operated by Jersey Oil & Gas, this is a 100mn boe field. This project's FDP approved in 2023. In early 2024, submitted the Buchan redevelopment project's environmental statement to the UK regulator. Located 115km offshore Aberdeen, this is the UK's third-largest undeveloped offshore oil resource. The environmental approval would be for a project with an electrification-ready floating production, storage and offloading vessel. In February 2024, Serica Energy purchased a 30.0% non-operated stake from Jersey Oil & Gas in the licences containing the Buchan field and the neighbouring J2 and Verbier discoveries. First oil production could be achieved end-2026.
- **Pilot:** operated by independent Orcadian Energy, this 79mn bbls of heavy oil field could see its development plan submitted for approval in 2024.
- **Cheviot Redevelopment:** A redevelopment of the Emerald field which ceased production in 1996. Owned by Waldorf, this project is uncertain at the time of writing, and the company has not specified whether it is likely to go through with this project.

However, again we note that with the arrival of the new Labour-led government and the new fiscal terms and policies regarding reduced investment allowances, many of these projects are at risk. We will wait to see industry reactions and final policies before updating our forecasts.

Decommissioning Important For Late-Life Recovery

An important catalyst for end-of-life asset transfers, and subsequently the maximisation of oil recovery from legacy assets, will be reforms to decommissioning tax liabilities for North Sea fields. A successful change in government legislation would allow a buyer of an asset to be able to access the same, or benefit from similar, tax relief on decommissioning costs, potentially through the transferal of tax history. We believe that the introduction of legislation through which both the seller and the buyer of a late-life asset are incentivised to achieve a deal will be a key catalyst for the development of decommissioning in the UK North Sea.

Incentivising the transfer of late-life assets will be a crucial dynamic in both the UK government's interest as well as companies operating in the North Sea. Smaller companies with a specific focus on maximising the production lifetime and profit from an ageing field will benefit from tax relief while maximising economic recovery for the UK government. Larger legacy operators in the North Sea have far less focus on extracting the very last barrels from ageing assets and the subsequent decommissioning process, which often lies outside of the key competencies of the larger oil and gas companies.

Oil Production (United Kingdom 2023-2028)

Indicator	2023e	2024e	2025f	2026f	2027f	2028f
Crude, NGPL & other liquids prod, 000b/d	733.8	801.7	774.8	740.6	727.2	723.2
Crude, NGPL & other liquids prod, % y-o-y	-11.4	9.3	-3.4	-4.4	-1.8	-0.6

e/f = BMI estimate/forecast. Source: EIA, BMI

Oil Production (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Crude, NGPL & other liquids prod, 000b/d	701.9	672.1	644.9	604.9	567.7	533.1
Crude, NGPL & other liquids prod, % y-o-y	-2.9	-4.2	-4.0	-6.2	-6.1	-6.1

f = BMI forecast. Source: EIA, BMI

Upstream Gas Production

Key View: *We hold a very bearish outlook for the UK's gas production outlook, with key North Sea mature fields continuing to see heavy decline rates, insufficient projects to boost output at these mature fields, and an insufficient amount of exploration to counter these decline rates. Gas production could decline from 30.8bcm in 2024 to 15.1bcm by 2034 (compared to levels of 42.1bcm as recently as 2017 and 73.5bcm in 2008), with some limited upside risks should some specific projects be pushed through in the context of higher gas prices. However, risks to our outlook now lie increasingly to the downside, given the new Labour government policy directions could catalyse further divestment from the UK upstream sector while warding off potential new buyers of legacy assets. This could further accelerate the decline of the country's offshore gas production sector.*

Latest Updates

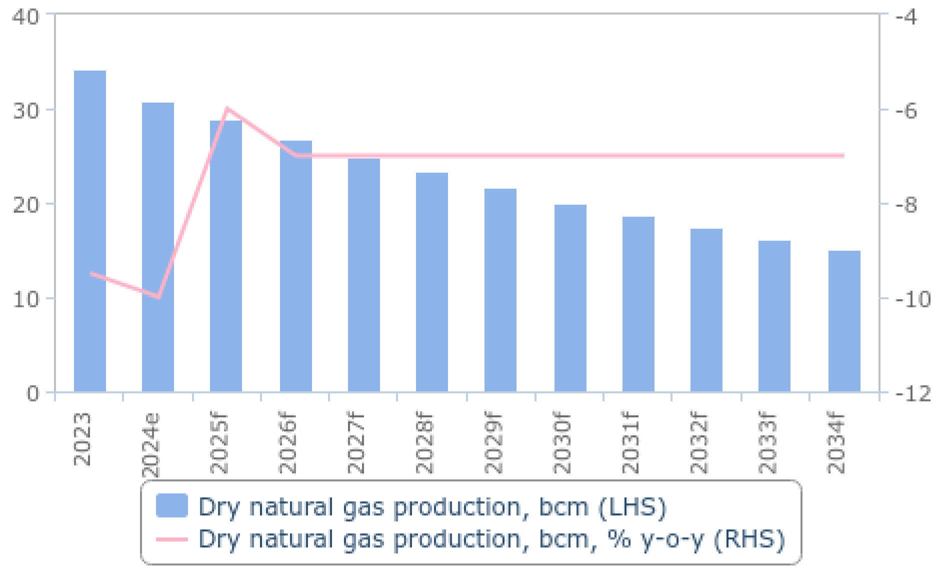
- We expect UK gas production to continue the recent trend of heavy declines, as we forecast the country's annual gas production to decline by 10.0% y-o-y in 2024 to an annual output of 30.8bcm, with another planned 6.0% y-o-y contraction in 2025. Provisional January-November 2024 gas production data show an impressive 10% y-o-y decline to date on the corresponding period of 2023, showing further downside risks to our 2024 and 2025 gas production outlook. The UK's annual gas production in 2023 already declined by a 9.0% y-o-y to 34.0bcm of gas output.
- Over the long term (2025-2034), we forecast UK gas production to decline at 6.9% y-o-y due to low exploratory drilling levels and high natural decline rates. By 2034, we expect production of 15.1bcm of gas. However, it is likely that some new field FIDs or brownfield and/or expansion projects could temper the decline rates.
- Similar to the oil production outlook, however, the outlook for gas exploration and production in the mature UK market has been further impacted this quarter in the context of the recent Labour victory at the July 2024 general elections (*see 'Exploration' and 'Oil Production' sections of this report for more informatio*n). Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-running declines in UK exploration and production. We therefore believe the new government will result in long-term downside risks to our already bearish gas production outlook. We have not yet revised down our forecasts, however, waiting for final policies to be decided/implemented, in order to gage company reactions and possible project delays/cancellations.
- In early 2024, Shell took an FID on the long-awaited Victory gas project in the UK's West of Shetland waters. This comes 47 years after the field was originally discovered by Texaco. The development will use a single subsea well that will be tied back to existing infrastructure at the Greater Laggan Area system (TotalEnergies). The field will produce 1.5bcm peak. Victory's gas will be processed onshore at TotalEnergies' Shetland gas plant.
- In March 2024, Perenco announced the successful start up of gas production from its C06 well, a near-field discovery within the Ravenspurn South area. Combined with the recent start-ups of new wells D15 and D16, the three wells will bring about 0.4bcm of production at peak.

Structural Trends

The largest concentration of natural gas production in the UK is the Shearwater-Elgin area in the Southern Gas Basin, which contains five major gas fields: Shearwater, Scoter, Halley, Franklin and Elgin. However, the country's gas production sector is very mature, and production has fallen substantially since its peak days. Production has fallen from highs of over 100.0bcm of production in the early 2000 to 37.3bcm by 2013. Production declines stabilised around the 40.0bcm level over the 2015-2020 period due to several near field and new field redevelopments, after 13 years of strong production decline rates. Production then returned to a downtrend past 2020 due to a drilling rate decline in the context of the low capex environment and high decline rates at mature North Sea fields, ending 2023 production levels of 34.2bcm in 2023.

Bearish Gas Production Outlook

UK - Gas Production Forecast (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The gas production decline rate in the UK in recent years reflects our view that the UK upstream will continue in a state of managed decline; however, the high energy price environment and Russia-Ukraine conflict could stimulate a brighter capex outlook in the near term, which will mitigate high natural decline rates. The Russia-Ukraine conflict has brought into the spotlight the reliance of Europe on Russian natural gas. The UK and EU are seeking ways to reduce reliance on Russian gas, due to concerns over security of supply.

Over the long term, we forecast UK gas production to decline at an average 6.9% y-o-y due to low exploratory drilling levels and high natural decline rates. By 2033, we expect production of 15.1bcm of gas; however, it is likely that some new fields FIDs or brownfield and/or expansion projects could temper the decline rates. Exploratory drilling, which is instrumental in adding reserves and production growth, has fallen in the UK in the last five years. Between 2013 to 2019, the number of exploratory wells drilled per year averaged 12. This level of exploration was enough to see UK gas production experience a small resurgence in production, from 37.3bcm in 2013 to 39.2bcm in 2019. If we take the 2013 production number of 37.31bcm and assume 9.0% natural decline rate y-o-y, then production would have been 17.5bcm by 2020, with no new fields brought online. Actual UK production reached 39.3bcm in 2020, which indicates that at least 21.8bcm of production growth must have come online. Our new project pipeline indicates that around 23bcm of production came online in the same time frame, confirming the approximate decline rate. While not all new projects could be considered as a result of exploration well drilling, and not all of the wells drilled were targeting gas or condensate, it shows that, on average, each exploration well added around 0.6bcm to UK production in a best-case scenario.

The past four years have seen among the lowest rates of exploration per annum since exploration began in the UK North Sea in the 1960s: 10, 5, 8 and 12 exploration wells drilled in 2020, 2021, 2022 and 2023 respectively. Allowing for a time lag, this would only represent a maximum upside of 9.6bcm of production growth to our forecast. Production decline in the UK may reach a natural decline rate in 2025 and 2026, without further exploratory drilling. We expect exploration activity to potentially decline further, given that the North Sea Transition Authority is expecting that spending on UK exploration and appraisal is set to average GBP0.32bn between 2023 and 2027. This is more than a third less than the GBP0.5bn averaged between 2018-2022.

Similar to the oil production outlook, however, the outlook for gas exploration and production in the mature UK market has further worsened in the context of the recent Labour victory at the July 2024 general elections. The new UK Labour government has announced in July 2024 a series of additional changes to the fiscal regime covering production in the UK and the UK Continental Shelf. Notably, they plan to raise the Energy Profits Levy by 3% and increasing taxes to 78%, on par with Norway's marginal tax rate. In addition, the manifesto had also called to end licensing for the exploration of new oil and gas fields. Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-running declines in UK exploration and production. We therefore believe the new government will result in long-term downside risks to our already bearish gas production outlook. We have not yet downgraded our forecasts however, waiting for final policies to be decided/implemented, in order to gage company reactions and possible project delays/cancellations.

Gas Production (United Kingdom 2023-2028)

Indicator	2023	2024e	2025f	2026f	2027f	2028f
Dry natural gas production, bcm	34.2	30.8	28.9	26.9	25.0	23.3
Dry natural gas production, bcm, % y-o-y	-9.5	-10.0	-6.0	-7.0	-7.0	-7.0
Dry natural gas production, % of domestic consumption	54.1	50.5	48.4	45.9	43.6	41.4

e/f = BMI estimate/forecast. Source: EIA, BMI

Gas Production (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Dry natural gas production, bcm	21.6	20.1	18.7	17.4	16.2	15.1
Dry natural gas production, bcm, % y-o-y	-7.0	-7.0	-7.0	-7.0	-7.0	-7.0
Dry natural gas production, % of domestic consumption	39.3	37.3	33.6	30.3	29.2	26.2

f = BMI forecast. Source: EIA, BMI

Refining

***Key View:** We forecast the UK's annual refining output will continue to contract over 2024 and 2025, weighed down by a weak domestic and regional fuel demand outlook. We also maintain a bearish outlook to 2033, as the decline in domestic and regional fuel demand is structural in nature. Coupled with growing competition from more efficient refiners in the Middle East and Asia, these factors will continue to weigh on the UK's refining output, with output of 933,000b/d by 2033, down from forecasted 1.10mn b/d in 2024. Risks lie further to the downside in the case of further refining capacity closures.*

Latest Updates

- We expect the UK's refined fuels production to continue its decline in 2024 and 2025, contracting by 1.0% y-o-y in 2024 and 8.0% in 2025 (following the closure of the Grangemouth refinery in 2025). Output will be weighed down by continued weakness in domestic and regional demand for fuels in the UK and Europe as a result of a bearish near-term macro outlook.
- Scotland's only oil refinery at Grangemouth will close in 2025 due to inefficiency and declining demand, leading to the loss of around 400 jobs. Petroineos plans to convert the site into an import terminal and explore low-carbon fuel options through Project Willow, supported by GBP20mn in funding from the UK and Scottish governments. Meanwhile, the Stanlow oil refinery in northern England is preparing to increase fuel sales by investing in infrastructure and adding storage capacity in response to Grangemouth's closure. Stanlow will become one of five remaining UK refineries and is part of the Hynet decarbonisation cluster, with plans to produce blue hydrogen supported by GBP20mn in government funding to meet long-term conventional oil product needs.
- We note that the Labour Party victory in the July 2024 general election could result in long-term stronger declines in domestic oil production, and could lead to even less investment targeted at the country's oil infrastructure. In this regard, we see the UK's crude oil and condensates production declining to 2034. Risks to our oil production forecasts being tilted to the downside given dissuasive policies being put in place by the new Labour government as regarding oil exploration and production. This will see net imports of crude oil from abroad increasingly necessary for the refining sector, with net crude imports rising from 287,000b/d in 2024 to 373,000b/d by 2034, further impacting the profitability of the UK refining sector. There is thus a strong risk of further refinery closures in the UK over our forecast period.
- We recently revised down our refined fuels production and refining capacity outlook from 2025 onwards on the back of announcements end-2023 by Petroineos and PetroChina that the Grangemouth refinery (150,000b/d) will be closed down by mid-2025. The unit is due to be converted into a fuel import terminal capable of importing refined fuels such as diesel, gasoline and jet fuel. We have adjusted our forecast accordingly.
- In 2024, Essar Oil announced a USD1.2bn investment plan to transform the Stanlow refinery into the world's first low-carbon refinery, with several projects, including the installation of a EET industrial carbon capture facility at Stanlow to be operational by 2028, and the shift to hydrogen fuel, replacing natural gas and other refinery fuels. The target would be to reduce approximately 2.0mn tonnes (95%) of carbon dioxide (CO_2) emissions at the refinery.
- In 2023, Prax Group announced a GBP300.0mn carbon capture and storage project for their Lindsey refinery. By 2028, the project aims to capture 1.0mn tonnes of CO_2 from the refinery per annum. This is equivalent to more than 85% of all CO_2 emissions associated with the facility.

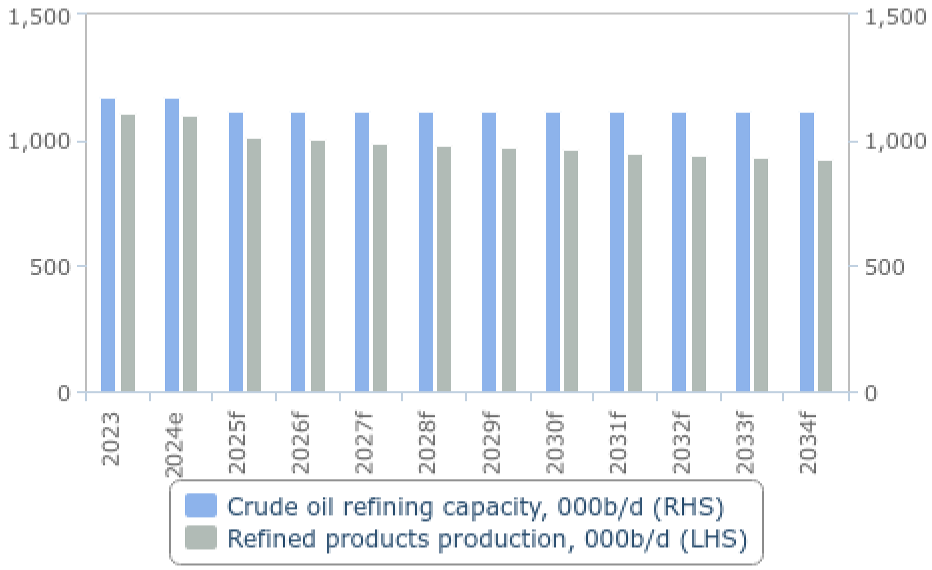
Structural Trends

The UK's production of refined oil products has fallen significantly since 1997, when production hit highs of 2.10mn b/d. The downward trend in production was especially notable in recent years, as refined oil output fell from 1.73mn b/d in 2007 to an estimated 1.11mn b/d in 2023. Output has ranged between 1.0mn-1.30mn b/d over the last five years.

The drop off in production since the mid-1990s is a logical result of UK refining capacity reductions caused by a poor business environment, as weaker demand, combined with high production costs - including for feedstock and labour - squeezed operating margins and saw frequent change in refinery ownership. The increase of more efficient and modern refineries being built and coming online in Asia and the Middle East have also created an increasingly difficult competitive context for older UK refineries, as is the case for most of European refiners. This has seen a significant reduction in refining capacity, falling from highs of nearly 2.0mn b/d of capacity prior to 2008, to current levels of 1.17mn b/d, and by extension, a strong decline in refined fuels production.

Grangemouth Closure To Cause Drop In Refining Capacity In 2025

UK - Refining Capacity Forecast (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The UK's refineries are traditionally geared towards gasoline production for transportation and fuel oil for electricity generation. With a higher percentage of diesel for transportation and the switch from fuel oil to other fuels for electricity generation, UK domestic refined fuels production is no longer fully aligned with domestic or regional fuels demand. This has resulted in the UK becoming a large gasoline and fuel oil net exporter, while becoming an increasing importer of jet fuel, kerosene and, within the last 10 years, diesel fuel.

While a decade ago the UK addressed this problem by exporting its oversupply of gasoline, for example to the US, European gasoline is increasingly uncompetitive. In the case of the US, the situation has reversed, with the shale gas and shale oil revolution. Not only have gasoline exports to the US fallen sharply but European gasoline producers are losing share in their traditional gasoline export markets to more competitive US gasoline producers that benefit from cheaper feedstock and lower energy costs. In addition, new Middle Eastern and Asian mega refineries that refine products significantly more efficiently than the older European refining fleet are also increasingly displacing European gasoline. Moreover, the changing nature of fuels demand, an an overall decline in refined fuels demand in Europe notably, partly a result of more efficient motorisations and the rise of the EV fleet, also continue to pose structural headwinds for UK refiners by reducing the domestic and regional market further for its fuels.

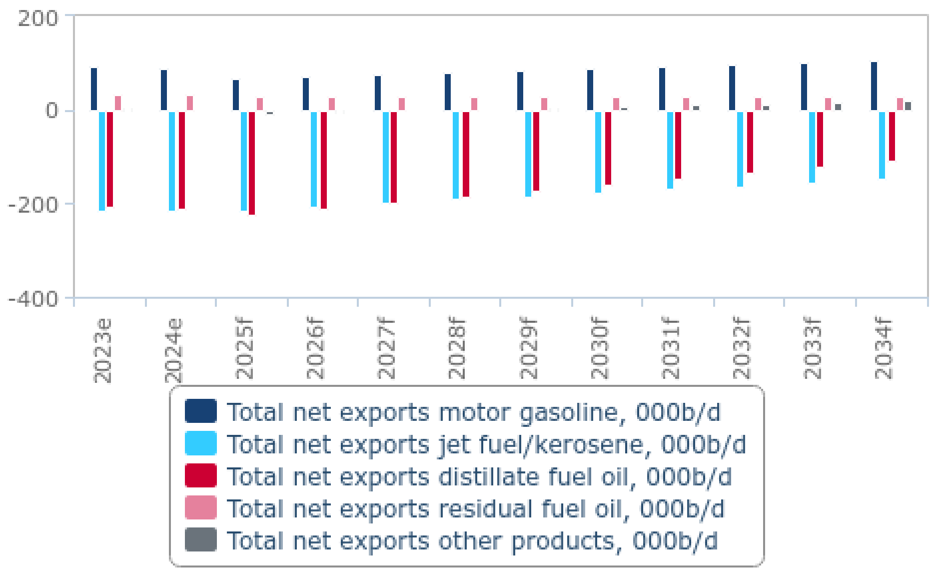
Grangemouth Refinery Closure Indicative Of Increasing Risks For UK Refining Sector

There is a continued downside risk to the UK's refining capacity, given the cheaper alternative of refined product imports. In the UK market, as with many of its European peers, supply and demand of refined products are no longer matched on a product-by-product basis, as highlighted in our refined fuels data.

In late 2023, Grangemouth refinery (150,000b/d) owners Petroineos and PetroChina announced that the facility will be permanently closed down by as early as the spring of 2025. The unit is due to be converted into a fuel import terminal capable of importing refined fuels such as diesel, gasoline and jet fuel. The closure of the refinery based in Scotland will reduce the total number of refineries in the UK to just five.

Mismatch In Fuels Production And Consumption

UK - Refined Fuels Net Trade Breakdown, '000b/d (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The closure of the refinery is set see the UK's total refining capacity decline by just over 10% by the middle of the present forecast period, to 1.12mn b/d. Refining output will be expected to fall by a similar margin. The closure highlights the increasing risks that threaten the profitability and thus feasibility of the remaining refineries in the UK, which are coming under intensifying pressure from increasingly stringent environmental norms, emissions targets, in addition to newly built and more efficient refineries in regions such as Asia and the Middle East. These developments stand in contrast to the highly aged refining infrastructure of the UK, in which the region's five remaining refineries are now, on average, 62 years old. Further headwinds that threaten the competitiveness of the UK's refining sector are the dwindling domestic availability of crude supplies.

We also note that the significant Labour Party victory in the July 2024 general election could further see long-term stronger declines in domestic oil production('see 'Oil Production' section of this report), and could lead to even less investment targeted at the country's oil infrastructure. In this regard, we see the UK's crude oil and condensates production declining to about 492,000b/d by 2033, from a forecasted 723,000b/d in 2024. Risks to production lie further to the downside given dissuasive policies being put in place by the new Labour government as regarding oil exploration and production. This will see net imports of crude oil from abroad increasingly necessary for the refining sector, with net crude imports rising from 297,800b/d in 2024 to 391,000b/d by 2034, further impacting the profitability of the UK refining sector. There is thus a strong risk of further refinery closures in the UK over our forecast period.

Latest Large Investments In Refining Sector

- In 2024, Essar Oil announced a USD1.2bn investment plan to transform the Stanlow refinery into the world's first low-carbon refinery, with several projects, including the installation of a EET industrial carbon capture facility at Stanlow to be operational by 2028, and the shift to hydrogen fuel, replacing natural gas and other refinery fuels. The target would be to reduce approximately

2.0mn tonnes (95%) of CO2 emissions at the refinery.

- In 2023, Prax Group announced a GBP300.0mn carbon capture and storage project for their Lindsey refinery. By 2028, the project aims to capture 1.0mn tonnes of CO2 from the refinery per annum. This is equivalent to more than 85% of all CO2 emissions associated with the facility.
- ExxonMobil took a final investment decision in April 2019 to move ahead with an expansion project at the Fawley refinery. The company aims to increase production of ultra-low sulphur diesel by 38,000b/d. The plans include building a hydrotreater unit to remove sulphur from diesel, which will be supported by a hydrogen plant. The programme was reportedly shelved at the start of 2020, due to the poor refining market. However, in 2022, Exxon has resumed the plans and will invest more than USD1.0bn in the project.
- In 2022, Phillips 66 announced a EUR500mn investment to evaluate the feasibility of using low-carbon hydrogen as a means of powering the industrial heaters at the Humber refinery. The study seeks to address concerns relating to the fact that the Humber region stands as the most carbon-intensive industrial region in the UK, approximated to emit roughly 12.4mn tonnes of carbon dioxide per annum.
- In 2022, Essar Oil announced plans for the construction of a new hydrogen generation plant at the refinery, in addition to other initiatives, in order to improve energy efficiency and reduce emissions. This USD54.0mn project was completed in 2023.

Refining Capacity And Refined Products Production (United Kingdom 2023-2028)

Indicator	2023	2024e	2025f	2026f	2027f	2028f
Crude oil refining capacity, 000b/d	1,170.0	1,170.0	1,119.0	1,119.0	1,119.0	1,119.0
Crude oil refining capacity, % y-o-y	-0.1	0.0	-4.4	0.0	0.0	0.0
Crude oil refining capacity, utilisation, %	94.9	94.0	90.4	89.5	88.6	87.7
Refined products production, 000b/d	1,110.6	1,099.5	1,011.5	1,001.4	991.4	981.5
Refined products production, % y-o-y	-6.7	-1.0	-8.0	-1.0	-1.0	-1.0
Refined products production & ethanol, 000b/d	1,127.8	1,116.9	1,029.1	1,019.2	1,009.3	999.6
Refined products production & ethanol, % y-o-y	-6.6	-1.0	-7.9	-1.0	-1.0	-1.0

e/f = BMI estimate/forecast. Source: EIA, BMI

Refining Capacity And Refined Products Production (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Crude oil refining capacity, 000b/d	1,119.0	1,119.0	1,119.0	1,119.0	1,119.0	1,119.0
Crude oil refining capacity, % y-o-y	0.0	0.0	0.0	0.0	0.0	0.0
Crude oil refining capacity, utilisation, %	86.8	86.0	85.1	84.3	83.4	82.6
Refined products production, 000b/d	971.7	962.0	952.3	942.8	933.4	924.1
Refined products production, % y-o-y	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
Refined products production & ethanol, 000b/d	990.0	980.4	971.0	961.6	952.4	943.3
Refined products production & ethanol, % y-o-y	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0

f = BMI forecast. Source: EIA, BMI

Refined Fuels Consumption

Key View: *We maintain our bearish long-term view for refined fuels consumption in the UK. An increasingly electrified vehicle fleet and falling demand for fuels in the industrial and residential sectors will result in a continued decline in demand, which we expect will fall from 1.43mn b/d in 2024 to 1.03mn b/d in 2034.*

Latest Updates

- Our Country Risk team has revised the GDP growth forecast downward in response to broad-based US tariffs. The projections are now 1.2% for 2025 and 1.3% for 2026, down from 1.4% and 1.8% respectively. While this decline is notable, it remains relatively marginal compared to other regions. As a result, we correspondingly revised down our fuel consumption outlook by a 0.2% downward revision in 2025 and 0.5% in 2025
- The UK government is easing EV sales targets to support the car industry amid a new 25% US tariff on car imports, impacting the UK as a major exporter. While the ban on new petrol and diesel car sales remains set for 2030, manufacturers now have more flexibility in meeting annual EV sales targets. This includes the ability to make up shortfalls in subsequent years and a reduction in fines for not meeting emissions standards. However, our Autos team does not anticipate this development having any significant implications on EV penetration in the market as a result we have made no adjustments to our fuel consumption outlook in leu of these news.
- The UK's Zero Emission Vehicle mandate, which requires 80% of new cars and 70% of new vans to be zero-emission by 2030 and 100% by 2035, informs our bearish outlook on refined fuels consumption. However, EV penetration is expected to fall short of the 2030 target by 9.85%, according to our Autos team.
- Over the long-term forecast period to 2034, we forecast a long term average decline. This will be driven in large part by the switch from internal combustion engines to EVs, given the large role currently played by the transport sector in the country's total oil demand. The UK's oil consumption is set to decrease over the long term, falling from an estimated 1.43mn b/d in 2024 to 1.03mn b/d in 2034. This can be compared to the peak of 1.80mn b/d of fuels demand in 2005.
- In the long term, growing societal awareness of inner city air pollution will accelerate plans and schemes for tougher vehicle emission standards across the country. This will temper distillate fuel consumption in particular.

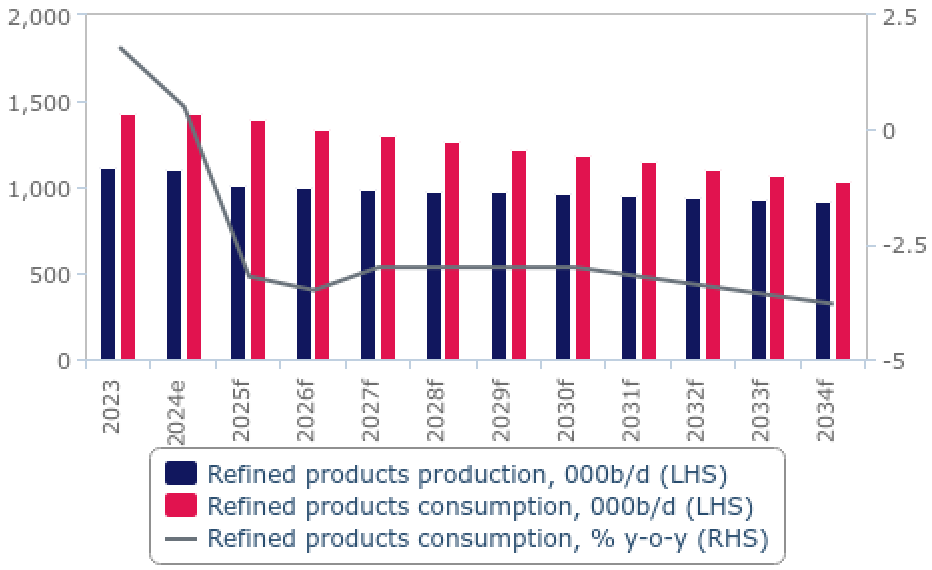
Structural Trends

The transport sector accounts for over three quarters of the UK's final oil consumption. The three main transport fuels (gasoline, jet fuel and diesel) account for over 70% of the UK's total demand for petroleum. The rest is spread across generation, industry use and residential heating. Around 6% of oil is used by industry with the remainder used for refinery fuel, heating homes and non-energy use (mostly petrochemical feedstock).

Distillate fuel is the largest fuel consumed in the UK. Up until the early 2000s, gasoline consumption exceeded diesel consumption; however, a large portion of the UK vehicle fleet has now switched to diesel and gasoline consumption has fallen consistently over the past two decades. We highlight risks to this trend coming from more stringent emissions standards in the form of Euro VI regulations. The increasing politicisation of the issue of inner city air pollution will accelerate plans to introduce more stringent emission controls at the expense of diesel vehicles.

Oil Consumption Set To Decrease Over The Long Term

UK - Refined Products Production & Consumption Forecast (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The UK's oil consumption is set to decrease over the long term, falling from an expected 1.40mn b/d in 2024 to 1.06mn b/d in 2033. This is down from a peak of 1.80mn b/d of fuels demand in 2005. Refined fuels consumption has fallen slowly since 2005 as a result of weaker economic performance, growing energy efficiency and the closure of oil-based power generation. Consumption also fell sharply in 2020 as a result of the Covid-19 pandemic, declining by 20.0% y-o-y. The full removal of Covid-19 measures resulted in a strong rebound in refined fuel consumption, which we estimate to have grown by 9.0% y-o-y in 2022 to 1.40mn b/d, and by another 2.0% in 2023 to an estimated 1.43mn b/d (notably supported by strong demand for air travel, which has seen demand for jet fuel increase by over 15.0% y-o-y in 2023.)

However, 2023 fuel demand remained around 10% below the pre-Covid demand of 1.56mn b/d that was registered in 2019. We do not see refined fuels demand returning to pre-pandemic levels over our forecast period, as increasing efficiency in new thermic based vehicles, and the increasing electrification of the UK's vehicle fleet will weigh down on demand for diesel and gasoline. Our Autos team expects that EVs to make up 5.4% of the entire vehicle fleet in 2024, a proportion which they forecast will rise to 27.5% by 2033. This will lead to a continued structural decline in fuels demand over the forecast period.

Refined Products Consumption (United Kingdom 2023-2028)

Indicator	2023	2024e	2025f	2026f	2027f	2028f
Refined products consumption, 000b/d	1,428.8	1,436.0	1,392.9	1,351.1	1,310.6	1,271.3
Refined products consumption, % y-o-y	1.8	0.5	-3.0	-3.0	-3.0	-3.0

e/f = BMI estimate/forecast. Source: EIA, BMI

Refined Products Consumption (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Refined products consumption, 000b/d	1,233.1	1,196.1	1,157.9	1,118.5	1,078.2	1,037.2
Refined products consumption, % y-o-y	-3.0	-3.0	-3.2	-3.4	-3.6	-3.8

f = BMI forecast. Source: EIA, BMI

Gas Consumption

Key View: *After the significant declines in annual gas demand seen over the last two years, we expect decreases in the UK's near-term gas consumption to continue on a downwards, although slower decline trend over both 2024 and 2025. This is notably on the back of our expectations for gas prices to remain elevated in the near term relative to historical averages. We are bearish on the prospects of natural gas consumption in the UK in the long term, due to competition from renewables in the power sector and the move away from gas boilers in UK newbuilds. We thus maintain our forecast of a structural decline for consumption over 2025-2034.*

Latest Updates

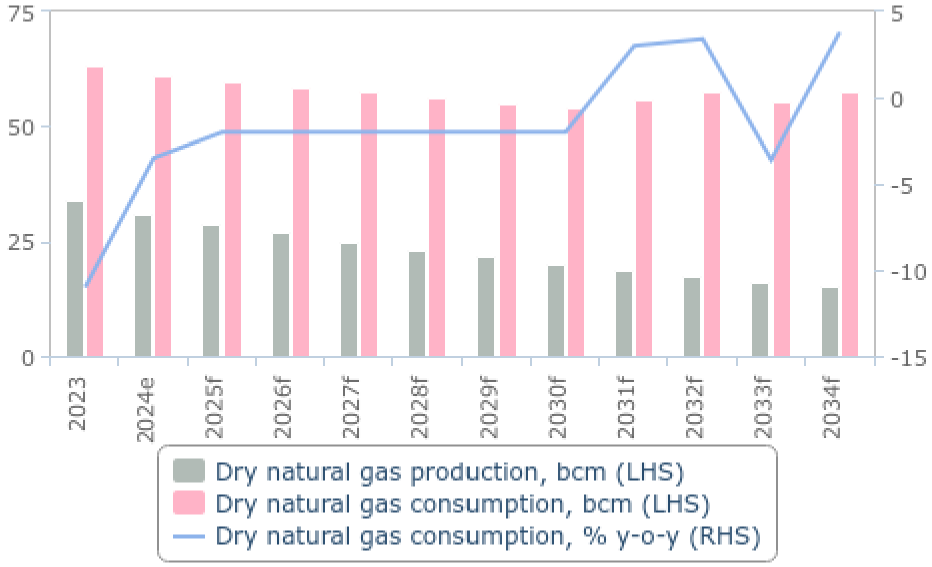
- Dutch TTF natural gas prices closed at EUR31.75/MWh on April 29, driven by a combination of potential economic strain from tariffs and reduced heating demand at the start of the shoulder season. While prices are currently steady, storage pressures are expected to elevate prices from Q2 to Q4 due to a significant gap in EU gas inventories, approximately 58bcm, needed for replenishment by the end of the year. The forecast for 2025 remains at EUR40/MWh, accounting for the impact of refilling inventories. For 2026, a more bearish outlook is anticipated, with prices averaging EUR32/MWh. As Dutch TTF natural gas prices remain steady with pressures expected to push them higher due to EU inventory gaps, UK gas consumers may face increased energy costs, particularly if these trends reflect on local markets. This could create upside pressures on heating and electricity costs.
- As of January 2025, The UK is facing critically low gas storage levels, with storage dropping from 57.4% on January 1 2025 to 32.9% by January 20 2025, compared to 82.0% during the same period in 2024. This limited capacity is leading to higher gas prices for households and increased competition for LNG. Additionally, natural gas's share in electricity generation is expected to decline from 32.7% in 2024 to 6.7% by 2033 as the UK shifts towards decarbonisation and renewable energy sources.
- We see UK gas demand continuing to contract in 2024 and 2025, although at a much lower extent than the declines seen in the previous two years. We forecast total gas consumption in the country to decline by 3.5% y-o-y in 2024 and 2.0% in 2025. This will partly be driven by the strong base effects of the consecutive heavy declines seen in both 2022 and 2023. To date, provisional January-June 2024 data show gas demand contracted by 4.6% on the corresponding 2023 period. The continuation of elevated gas prices in the country in the near term, which has been a key driver of reductions in gas demand in recent years, will continue to weigh on gas demand over the remainder of 2024 and into 2025.
- We forecast gas demand to come in at 61.0bcm in 2024 and 59.8bcm in 2025, down from estimated levels of 63.2bcm in 2023 and 71.1bcm in 2022.
- The UK's total annual gas consumption in 2023 declined by around 10.0% y-o-y. Strong declines were seen across all sectors, with continued elevated gas prices weighing on residential gas demand. Gas to power generation was also down across the year, due to record high prices for imports of electricity and consequent electricity demand reduction in the target.
- In June 2023, Centrica announced the completion of expansion work at the Rough gas storage facility, almost doubling its total storage capacity from 0.8bcm previously to 1.5bcm. Although the expansion is intended to strengthen the UK's energy security, it will do little in this regard, given that the UK's total gas storage capacity still remains scarce, especially relative to regional peers such as Germany and Italy.
- We are increasingly bearish on the prospects of natural gas consumption in the UK in the long term, due to competition from renewables in the power sector and the move away from gas boilers in UK newbuilds. We thus maintain our forecast of 2.0% y-o-y decline for consumption over 2025-2034, in which annual gas consumption is forecasted to decline to 57.6bcm by 2034.

Structural Trends

Domestic end-users (particularly for residential heating purposes) and the power sector make up about 66% of the UK's total gas demand. This is followed by industry use (13.0%), other final users (11.0%) and energy industry use (7.0%).

Gas Demand To Enter A Long-Term Decline

UK - Gas Production & Consumption Forecast (2023-2034)

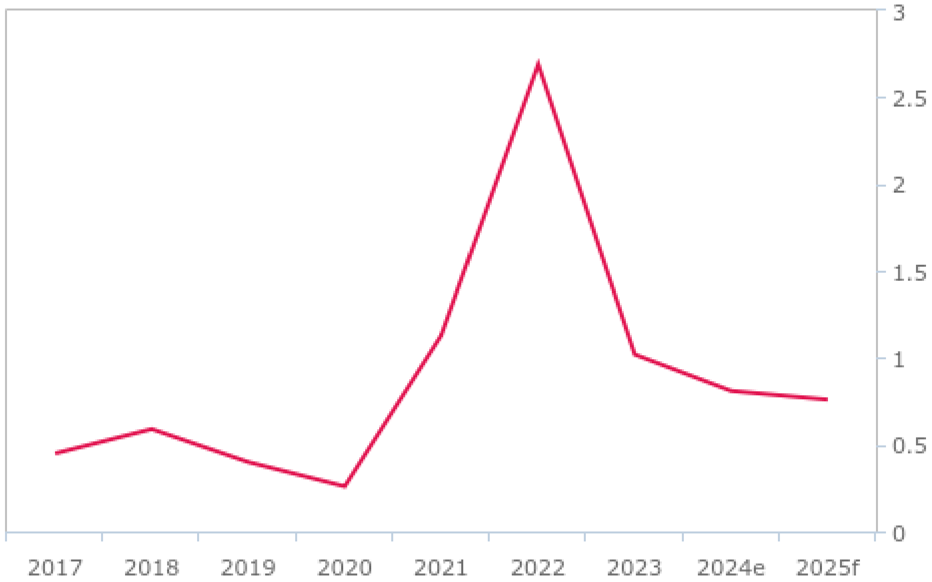


e/f = BMI estimate/forecast. Source: EIA, BMI

After two years of strong gas demand reduction in 2022 and 2023 (7.0% and 11.0% y-o-y reductions respectively), we expect demand contractions to continue in 2024 and 2025 with a forecasted 3.5% y-o-y decline in 2024 and 2.0% y-o-y in 2025. We forecast gas demand to come in at 61.0bcm in 2024 and 59.8bcm in 2025, down from estimated levels of 63.2bcm in 2023 and 71.1bcm in 2022. In the near term, we expect the price of natural gas to remain elevated in the UK, averaging GBP1.0/thermal unit (therm) in 2024 and GBP0.9/therm in 2025, after high levels GBP1.03/therm in 2023. This would be more than double the price averaged from 2014-2020 (GBP0.4/therm average over the 2014-2020 period). As a result, we expect further demand destruction to occur in industrial and residential settings.

UK Gas Prices To Remain Elevated

UK Gas Price, NBP GBP/thermal unit

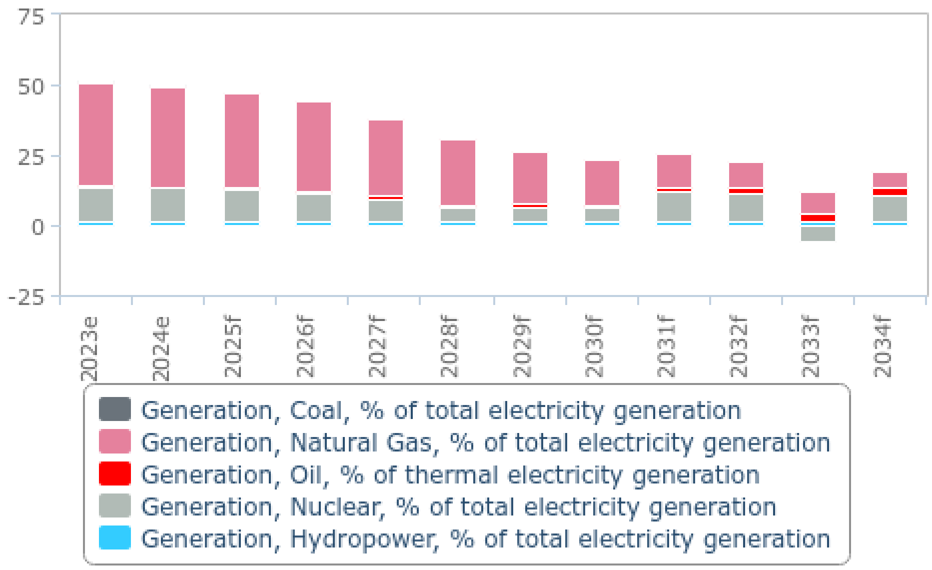


e/f = BMI estimate/forecast. Source: EIA, BMI

We are increasingly bearish on the prospects of natural gas consumption in the UK in the long term, as increasing competition from renewables in the power sector is expected to diminish the role of natural gas in electricity generation. Our Power & Renewables team forecasts that natural gas will account for just 6.7% of total electricity generation by 2034, declining significantly from the estimated 32.7% of electricity generation expected in 2024. Gas generation will decline at an average yearly rate of 12.9% over the 2024-2033 forecast period. Despite the successive changes in UK government leadership over the past years, we expect that low carbon energy supply will continue to be a primary focus of future governments. The extent of renewable penetration in the UK will be further enhanced by an increase in the amount of power storage projects in the country.

Increasing Role Of Renewables To Diminish Role Of Natural Gas In Electricity Generation

UK - Electricity Generation By Type (2023-2034)



e/f = BMI estimate/forecast. Source: National sources, BMI

Gas Consumption (United Kingdom 2023-2028)

Indicator	2023	2024e	2025f	2026f	2027f	2028f
Dry natural gas consumption, bcm	63.2	61.0	59.8	58.6	57.4	56.3
Dry natural gas consumption, % y-o-y	-11.0	-3.5	-2.0	-2.0	-2.0	-2.0

e/f = BMI estimate/forecast. Source: EIA, BMI

Gas Consumption (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Dry natural gas consumption, bcm	55.1	54.0	55.7	57.6	55.5	57.6
Dry natural gas consumption, % y-o-y	-2.0	-2.0	3.0	3.4	-3.6	3.8

f = BMI forecast. Source: EIA, BMI

Oil Trade

Key View: *A declining domestic crude production sector will result in progressively higher crude oil net import requirements throughout the forecast period, assuming relatively stable refining utilisation rates. The country's imports of refined fuel are set to reduce slowly over the forecast period, in line with declining domestic fuel demand.*

Crude Oil

Latest Updates

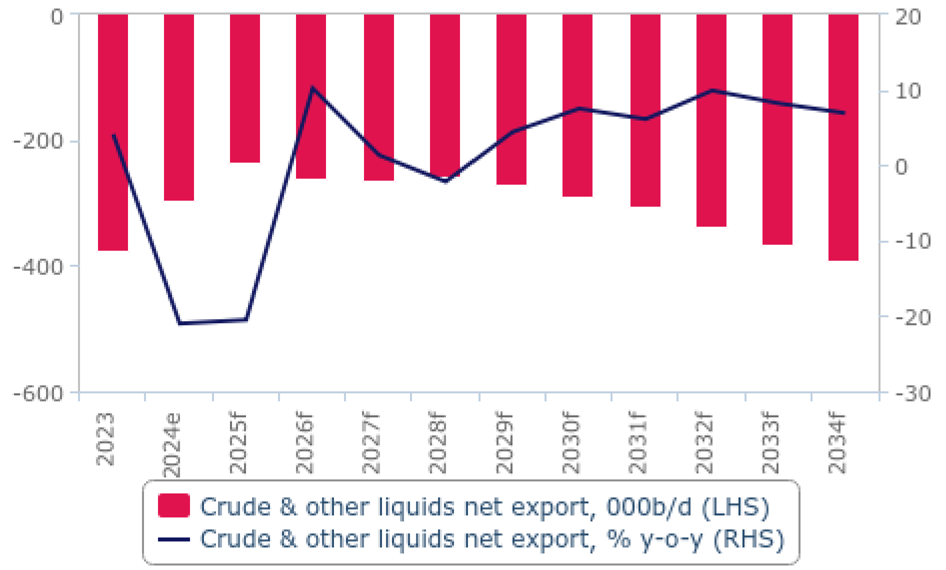
- We see the UK's annual imports of crude oil declining slightly, from an estimated 377,000b/d in 2023 to 237,000b/d in 2025, as a minor improvement in the country's near-term domestic crude production is set to reduce the country's crude import dependency.
- We expect UK production of crude oil to decline and crude imports to rise over the long term. This is because we expect exploratory drilling activity to remain subdued, which will consequently ensure that UK production continues to decline. This will see increased crude oil requirements through to 2034, to feed refineries.
- This quarter, we note the new Labour government could pose upside risks to crude oil import requirements. As noted in the 'Exploration' section of this report, deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-running declines in UK production and increasing the country's reliance on imported crude. However, in the long term, an accelerated shift to low-carbon energy could soften the UK's import dependence, improving its energy trade balance. This will be critical in ensuring domestic declines in oil and gas production and consumption translate into net reductions in GHG emissions on a global scale.
- The UK no longer imports any Russian crude oil (since 2022 and 2023), following Russia's invasion of Ukraine in 2022. The UK's oil imports are now being mostly provided by Saudi Arabia, Belgium, UAE, South Korea and the Netherlands.

Structural Trends

The UK became a net crude importer in 2005, as crude oil and condensates production from the maturing North Sea fell at startling rates. Output fell from a peak of 2.7mn b/d in 1999 to 0.93mn b/d in 2021. The UK's net crude imports increased accordingly, rising to an estimated 377,000b/d in 2023.

Oil Imports On The Decline

UK - Crude Oil Net Exports Forecast (2023-2034)



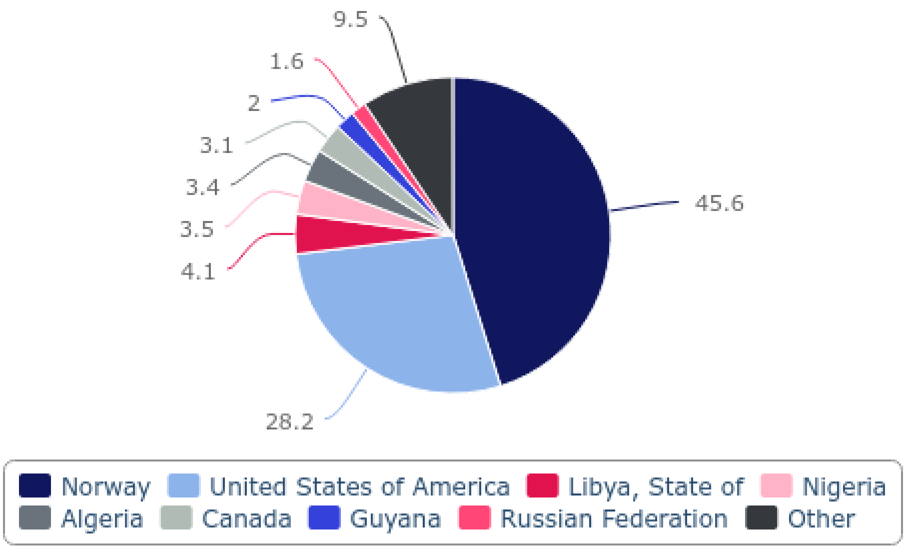
Note: Negative implies imports; e/f = BMI estimate/forecast. Source: EIA, BMI

While the UK's crude oil production could be sufficient to meet about two-thirds of refinery demand, there is an active trade in oil, which sees crude oil imported and exported to meet global and UK demand. Given its falling crude production, the UK is a significant crude net importer position, and is expected to import around 298,000b/d in 2024 and 237,000b/d in 2025. This is slightly lower than 2023 figures, due to lower refining utilisation rates and a temporary increase in domestic oil production over 2024 and 2025.

The UK's key crude export markets are the Netherlands, Mainland China, Germany, France and Poland, which collectively account for about 74% of exports. The principal source of the UK's crude oil imports is Norway, which accounts for about half of all imports in the UK due not only to its geographical proximity but to the similarity of its crude types. More recently, imports from the US have increased significantly, as the UK is cutting off Russian oil imports entirely, making up around 28% of total supply, compared with levels of 14.0% in 2021.

Norway Dominates UK Supply, US Growing Share

UK - Crude Imports By Source Country, % of supply



Source: Trade Map, BMI

The UK's falling refining capacity and refinery throughput will result in lower demand for crude oil over the long term. Due to record refining margins, UK refiners have maximised output; however, we now expect refined fuels production to start falling back in the near term, declining to 1.09mn b/d in 2024. The UK refining sector has undergone a significant capacity reduction, falling from 1.85mn b/d in 2007 to 1.17mn b/d in 2023. We expect another capacity contraction in 2025, with the closure of the Grangemouth refinery in 2025. This will see capacity fall further, to 1.12mn b/d from 2025 onwards. Over the long term, we expect that the UK will continue to rely on imported crude oil as imports will balance the drop in domestic production of crude.

We also note that the arrival of a new Labour government following the General Elections held in July 2024, could pose upside risks to crude oil import requirements. As noted in the 'Exploration' section of this report, deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors, exacerbating long-running declines in UK production and increasing the country's reliance on imported crude. However, in the long term, an accelerated shift to low-carbon energy could soften the UK's import dependence, improving its energy trade balance. This will be critical in ensuring domestic declines in oil and gas production and consumption translate into net reductions in GHG emissions on a global scale.

Crude Oil Net Exports (United Kingdom 2023-2028)

Indicator	2023	2024e	2025f	2026f	2027f	2028f
Crude & other liquids net export, 000b/d	-376.8	-297.8	-236.8	-260.8	-264.2	-258.3
Crude & other liquids net export, % y-o-y	4.1	-21.0	-20.5	10.2	1.3	-2.2

e/f = BMI estimate/forecast. Source: EIA, BMI

Crude Oil Net Exports (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Crude & other liquids net export, 000b/d	-269.7	-289.8	-307.4	-337.9	-365.7	-391.0
Crude & other liquids net export, % y-o-y	4.4	7.5	6.1	9.9	8.2	6.9

f = BMI forecast. Source: EIA, BMI

Refined Fuels

Latest Updates

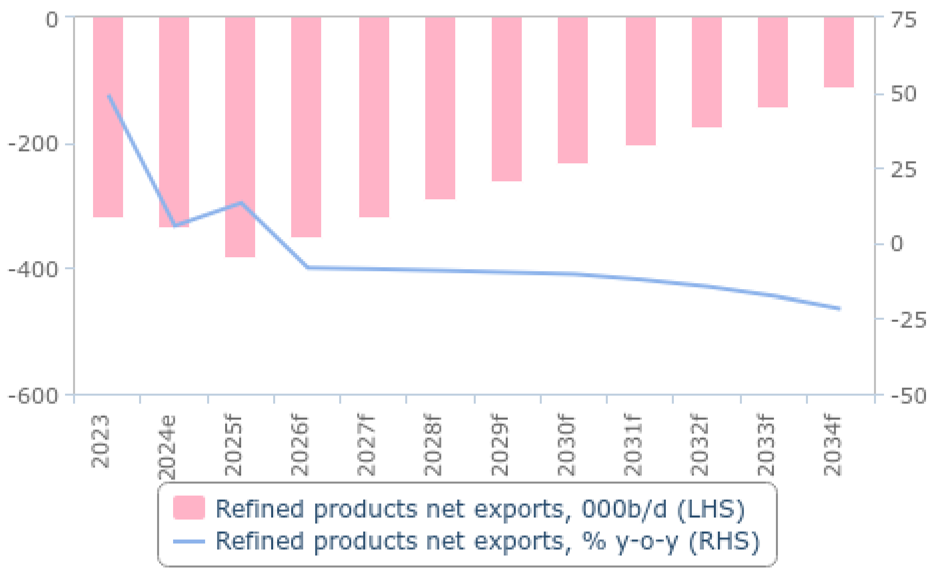
- We expect the UK's imports of refined fuels to marginally decline to 337,000b/d in 2024 before reaching 113,200b/d by 2034, as the country's refined fuels demand weakens faster than refined fuels output. Over the long term, we expect imports to continue declining as domestic demand to continue falling as a result of the increasing electrification of the UK's vehicle fleet.
- Prior to Russia's invasion of Ukraine, Russia accounted for about 8% of the UK's diesel imports. The continued strengthening of sanctions may cause disruption, which will impact prices. June 2022 represented the first year on record when the UK imported no refined products from Russia.

Structural Trends

In 2013, the UK became a net importer of refined products due to its shrinking refining capacity. The closure of the Milford Haven refinery in 2014 accentuated this trend, with initial refined fuels imports of 73,080b/d in 2013 rising to 156,000b/d in 2014. We forecast that the UK will import around 301,000b/d in 2024, after an estimated high of 318,000b/d in 2023.

Fuel Imports To Drop

UK - Refined Products Net Exports Forecast (2023-2034)



Note: Negative implies imports; f = BMI forecast. Source: EIA, DECC, BMI

Demand and supply are not matched on a product-by-product basis. The UK's refineries are traditionally geared towards gasoline production for transportation and fuel oil for electricity generation. With the recent increase in the use of diesel for transportation and the switch from fuel oil to other fuels for electricity generation, UK domestic refined fuels production is no longer aligned with domestic fuels demand. This has resulted in the UK becoming a large gasoline and fuel oil exporter, while becoming an increasingly large importer of jet fuel, kerosene and diesel fuel. The instigation of IMO 2020 will affect fuel oil production in the UK, with an expected drop in demand for heavy fuel oil from the shipping sector. This could place UK refiners under further squeeze.

In terms of refined product imports, the largest sources of refined product imports into the UK originate from Sweden, Belgium and the Netherlands. The US, Kuwait, Saudi Arabia, India, Korea and Finland are other important refined fuel exporters to the UK. Traditionally, refined fuel exports from the UK go to the US. The other major markets for UK refined fuel exports are Ireland, the Netherlands, Belgium and Canada.

The UK will continue to be a net importer of fuels over the medium term. However, we believe that the volume of refined products imports will decline, as the UK will see growing efficiency gains in the transport sector. The sector represents about 70% of total UK refined fuel consumption. We expect this trend to continue.

Refined Fuels Net Exports (United Kingdom 2023-2028)

Indicator	2023	2024e	2025f	2026f	2027f	2028f
Refined products net exports, 000b/d	-318.2	-336.5	-381.4	-349.7	-319.2	-289.8
Refined products net exports, % y-o-y	49.3	5.7	13.3	-8.3	-8.7	-9.2
Refined products net exports, USDbn	-13.6	-12.7	-14.3	-12.4	-10.9	-9.8

e/f = BMI estimate/forecast. Source: EIA, BMI

Refined Fuels Net Exports (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Refined products net exports, 000b/d	-261.4	-234.2	-205.5	-175.7	-144.8	-113.2
Refined products net exports, % y-o-y	-9.8	-10.4	-12.2	-14.5	-17.6	-21.8
Refined products net exports, USDbn	-9.0	-8.1	-7.2	-6.2	-5.2	-4.2

f = BMI forecast. Source: EIA, BMI

Gas Trade

***Key View:** Gas imports are expected to increase very slightly to 29.0bcm in 2024 and 30.2bcm in 2025. This is due to strong declines in domestic production, despite lowering domestic demand for gas. The UK's imports of LNG are set to continue to decline in the near term, as the significant build out of LNG import capacity in neighbouring European countries is expected to diminish the recent role played by the UK as an important entry point for LNG into the European continent. Over the long term, we expected a slow increase in gas import net requirements given strong decline rates in gas production in the North Sea, and this despite falling demand for gas throughout the forecast period to 2034.*

Latest Updates

- The UK is increasingly relying on LNG imports due to critically low gas storage levels and increased regional competition. In 2024, US LNG imports accounted for 70.2% of the UK's total LNG imports, displacing Russian LNG. LNG imports are expected to rise by 7.1% in 2025, while pipeline gas imports are forecasted to decrease by 2.1%. The competition for LNG cargos is expected to intensify as Europe seeks to replace lost Russian gas imports, potentially driving prices higher.
- Gas imports are expected to increase very slightly to 30.2bcm in 2024 and 30.8bcm in 2025. This is due to strong declines in domestic production, despite lowering domestic demand for gas. This reflects an increase in net exports by 4.2% in 2024 and 2.1% in 2025.
- We expect the UK's annual imports of LNG to continue declining moderately in the near term, from 19.4bcm of imports in 2023 to 14.0bcm of imports in 2024 and 15.0bcm in 2025. The UK's annual imports of LNG reached a record high 25.6bcm in 2022, driven by the UK's role as an entry point for LNG imports into Europe due to the lack of LNG import capacity in countries such as Germany at the time. However, neighboring countries, particularly Germany, are bringing online larger LNG import capacity, reducing the need for LNG imports into the UK. The LNG net exports for the UK are expected to be -14.0bcm in 2024 and -15.0bcm in 2025, with LNG making up 46.3% of total gas exports in 2024 and 48.6% in 2025.
- Pipeline gas net exports are projected to be -14.0bcm in 2024 and -15.0bcm in 2025, accounting for 46.3% and 48.6% of total gas exports respectively. This reflects a significant increase of 68.6% in 2024, followed by a decrease of 2.3% in 2025.
- Looking ahead, the trend in gas exports continues with dry natural gas net exports expected to be -31.7bcm in 2026, -32.4bcm in 2027, and -33.0bcm in 2028, with pipeline gas net exports increasing to -19.0bcm by 2028. LNG net exports are forecasted to remain at -14.0bcm from 2026 to 2028.
- In early 2024, Grain LNG signed a 10-year deal with Sonatrach to extend the Algerian company's long-term storage and redelivery capacity at the Grain LNG import terminal beyond January 2029. The deal is for 3.0mtpa of LNG import capacity and it is the first to be announced under Grain LNG's competitive auction process which launched in September 2023 for 9.0mtpa of capacity. The terminal (located in Kent) is currently being expanded to store and deliver enough gas to meet up to 33% of British gas demand.
- In 2023, Centrica reached an USD8.0bn agreement with US company Delfin Midstream to import 1.0mtpa of LNG on a 15-year Free on Board basis. First delivery of LNG is expected in 2027, depending on the successful completion of the Deepwater Port project.
- The US emerged as the largest LNG supplier to the UK in 2022, constituting around half of the UK's total LNG imports. LNG imports from the US more than trebled relative to 2021. In 2022, Qatar accounted for 30.0% of the UK's total LNG imports, down from 39.0% in 2021. Initial estimates for full-year 2023 data shows the breakdown to be similar, with the US still representing over half of the UK's LNG imports.

Structural Trends

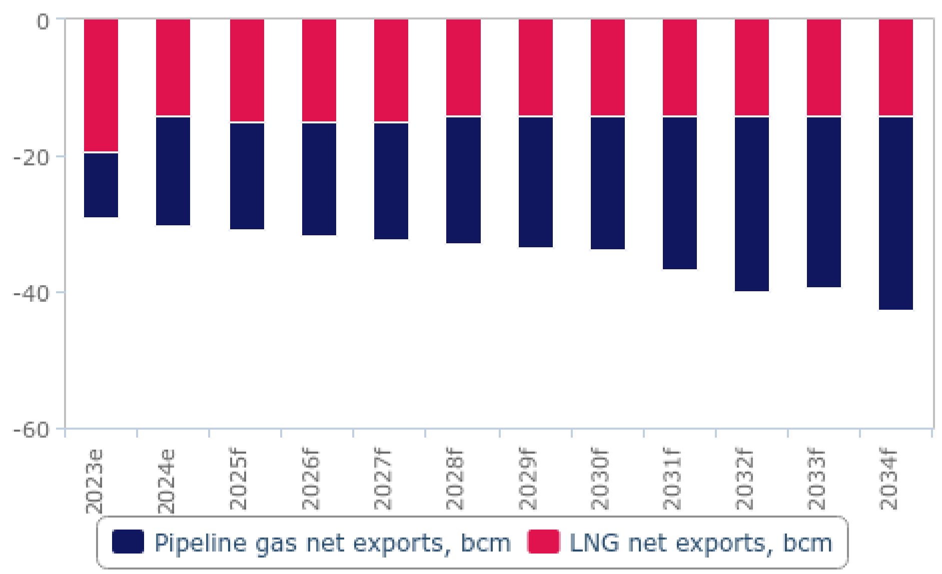
The UK is a large net gas importer, with net gas imports of about 29.0bcm in 2023. However, this is a significant decline on net import requirements of 43.6bcm in 2021, given the extent of gas consumption contractions witnessed over 2022 and 2023. Gas imports are expected to increase very slightly to 29.5bcm in 2024 and 30.2bcm in 2025. This is due to strong declines in domestic production, despite lowering domestic demand for gas. Over the long term, we expect the UK's reliance on imports to increase due to declining domestic production, with net gas imports expected to reach 42.5bcm by 2034.

Growing Role For LNG

The UK will remain an important destination for LNG cargoes over our forecast period to 2034, with Qatar and the US supplying the majority of imports. Qatar announced plans to expand the LNG import capacity at the Milford Haven terminal, which it owns, in South Wales by up to 25.0%. Qatar currently holds six of the seven LNG supply contracts. While Qatar will remain a key supplier over the next 10 years, we expect this dominant position to be increasingly challenged by volumes from the US. We expect the UK, and more broadly Europe, to be one of the main recipients of US LNG cargoes, with the major portfolio players selling into the continent's underused import terminals.

LNG Imports To Deepen In Near Term

UK - Gas Net Exports Forecast, bcm (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

UK's Gas Supply Network

The UK has six major gas import pipelines with a combined capacity of about 100.0bcm: Bacton-Zeebrugge (Belgium, 27.0bcm), BBL (Netherlands, 19bcm), Vesterled (Norway, 13.0bcm), Tampen (Norway, 9.0bcm), Gjoa (Norway, 6.0bcm) and Langeled (Norway, 25.0bcm).

The UK currently has four operating LNG terminals with a combined import capacity of about 55.0bcm: Grain LNG on the Isle of Grain in Kent (20.0bcm); GasPort LNG in Teesside, north-eastern England (6.0bcm); and South Hook (22.0bcm) and Dragon (7.0bcm), both located at Milford Haven in Wales. In practice, no LNG has been imported via Teeside GasPort over the past years. The vast majority (86.0%) of LNG is imported through the South Hook terminal.

Trafigura confirmed that it is looking to re-open its Teeside LNG facility, which it closed in 2012 due to a lack of activity. The plans to re-open the facility signals the growing appetite for gas imports in the UK, with LNG cargoes becoming increasingly competitive with pipeline imports, as hub-linked exports from the US grow in availability.

In November 2022, Qatar also announced plans to invest several hundred million pounds in the South Hook LNG terminal in order to to increase the capacity of the terminal to 20.0mtpa from 15.6mtpa currently. However, plans are still preliminary, with the expansion is expected to be completed by H2 2025.

Gas Net Exports (United Kingdom 2023-2028)

Indicator	2023e	2024e	2025f	2026f	2027f	2028f
Dry natural gas net exports, bcm	-29.0	-30.2	-30.8	-31.7	-32.4	-33.0
Dry natural gas net exports, % y-o-y	-12.8	4.2	2.1	2.7	2.2	1.9
Dry natural gas net exports, USDbn	-12.0	-12.0	-11.5	-11.7	-11.9	-12.1
Pipeline gas net exports, bcm	-9.6	-16.2	-15.8	-16.7	-17.4	-19.0
Pipeline gas net exports, % y-o-y	25.9	68.6	-2.3	5.2	4.3	9.2
Pipeline gas net exports, % of total	33.2	53.7	51.4	52.7	53.7	57.6
LNG net exports, bcm	-19.4	-14.0	-15.0	-15.0	-15.0	-14.0
LNG net exports, % y-o-y	-24.3	-27.8	7.1	0.0	0.0	-6.7
LNG net exports, % of total gas exports	66.8	46.3	48.6	47.3	46.3	42.4

e/f = BMI estimate/forecast. Source: EIA, BMI

Gas Net Exports (United Kingdom 2029-2034)

Indicator	2029f	2030f	2031f	2032f	2033f	2034f
Dry natural gas net exports, bcm	-33.5	-33.9	-36.9	-40.1	-39.3	-42.5
Dry natural gas net exports, % y-o-y	1.5	1.2	8.9	8.7	-2.1	8.3
Dry natural gas net exports, USDbn	-12.3	-12.5	-13.6	-14.8	-14.5	-15.7
Pipeline gas net exports, bcm	-19.5	-19.9	-22.9	-26.1	-25.3	-28.5
Pipeline gas net exports, % y-o-y	2.7	2.1	15.2	14.0	-3.3	12.8
Pipeline gas net exports, % of total	58.2	58.7	62.1	65.1	64.4	67.1
LNG net exports, bcm	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0
LNG net exports, % y-o-y	0.0	0.0	0.0	0.0	0.0	0.0
LNG net exports, % of total gas exports	41.8	41.3	37.9	34.9	35.6	32.9

f = BMI forecast. Source: EIA, BMI

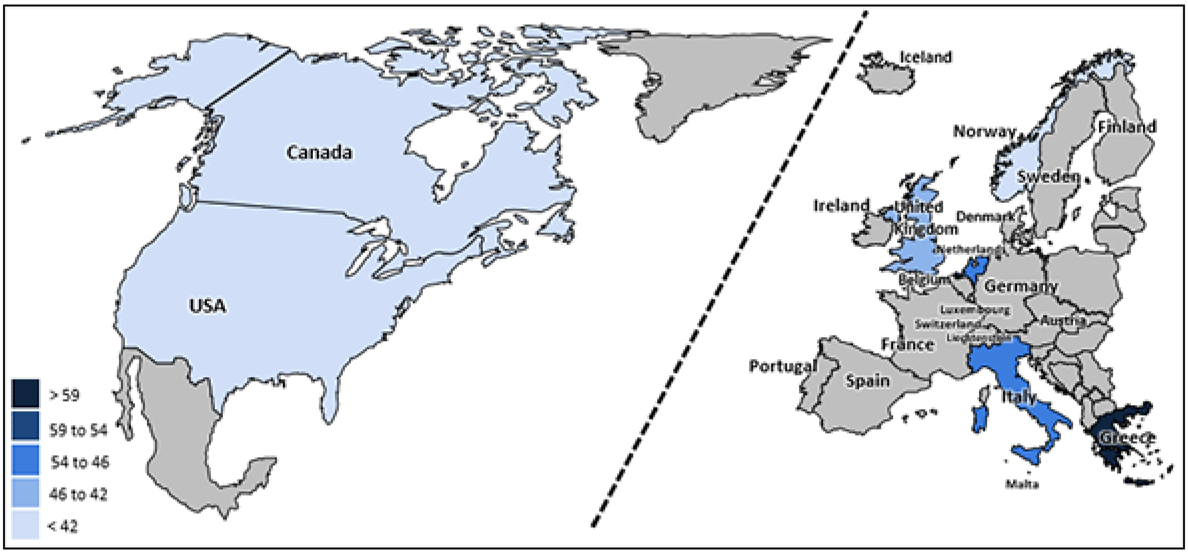
Industry Risk Reward Index

North America And West Europe Upstream Oil & Gas Risk/Reward Index

Key View: *The NAWE region houses some of the largest oil and gas producers, which offer favourable above and below-ground rewards. That said, we recognise a distinction between the North American upstream markets, for which we hold relatively bullish outlook, and the European markets, which in most part are behind their peak in producing.*

Canada And US Outperform Region

NAWE - Upstream Risk/Reward Index Heatmap



Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

Main Regional Features & Latest Updates

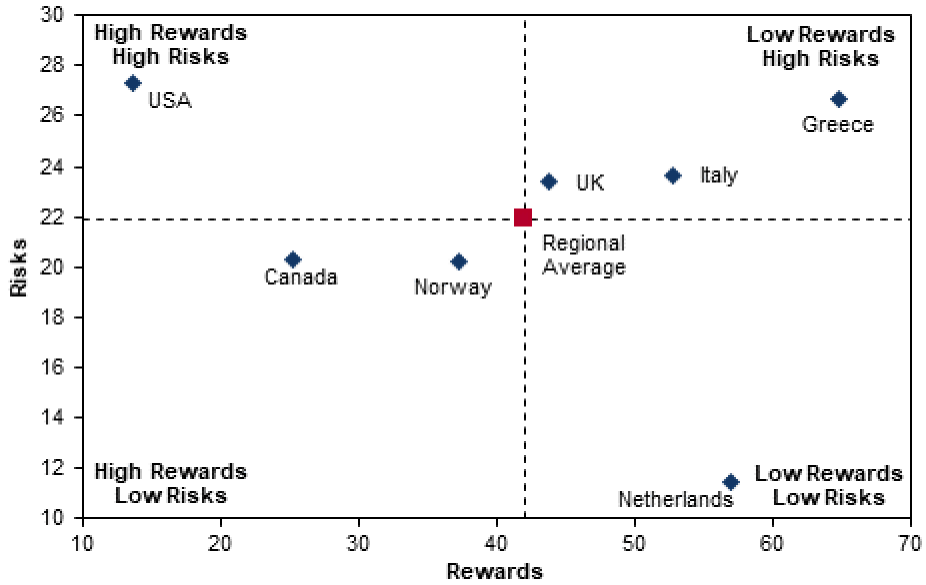
- The NAWE Region dominates in the Global Upstream Oil & Gas Risk/Reward Index (RRI), housing the US and Canada, which sit respectively at the first and third position globally.
- The region's Upstream RRI sits at 40.1, outperforming the global average and holding the pole position among all regions.
- Despite the attractiveness of the North American producers, the region underperforms the global average in Industry Rewards, being weakened by the scores for the Netherlands and Greece. NAWE Industry Rewards sit at 51.5, slightly above the global average of 50.0.
- While the region is relatively attractive with regards to oil reserves and hydrocarbon production, it underperforms in the Hydrocarbon Production Growth category.
- That said, the region outperforms the global average in all other index categories. Starting with Country Rewards, the region scores 27.9, substantially below global average. The NAWE region is attractive in Country Rewards amid very limited state asset ownership, scored at 21.0, coupled with high infrastructure integrity and healthy competitive landscape.
- The NAWE region also offers relatively low risks. The Industry Risk score for the region sits at 24.2, substantially below the global average. The low score is supported by favourable license type and low risks related to bureaucratic and legal environment. However, the region sees less favourable royalties and fiscal regimes, which weigh on the regional score.
- NAWE's score in the Country Risks category outperforms all other categories, with the score of 12.3. The region sees very limited Political Risk (9.9), Operational Risk (9.3). Economic risk scores are also favourable with Short- and Long-Term Risk score at respectively 20.4 and 14.7.
- The US sits comfortably at the pole position in the region, with Upstream RRI score of 15.0. The US sees vast below-ground

advantages which boost the Industry Rewards score of 13.9. However, the country performs well across all categories with the weakest performance in Industry Risks, scoring at 30.4.

- Canada follows the US in the regional ranking. In Europe, Norway and the UK, dominate the ranking, and outperform the global average. Greece, the Netherlands and Italy offer lower rewards which weigh on the overall score for these markets.

Clear Divide Between North American and Western European Markets

NAWE - Upstream RRI Snapshot



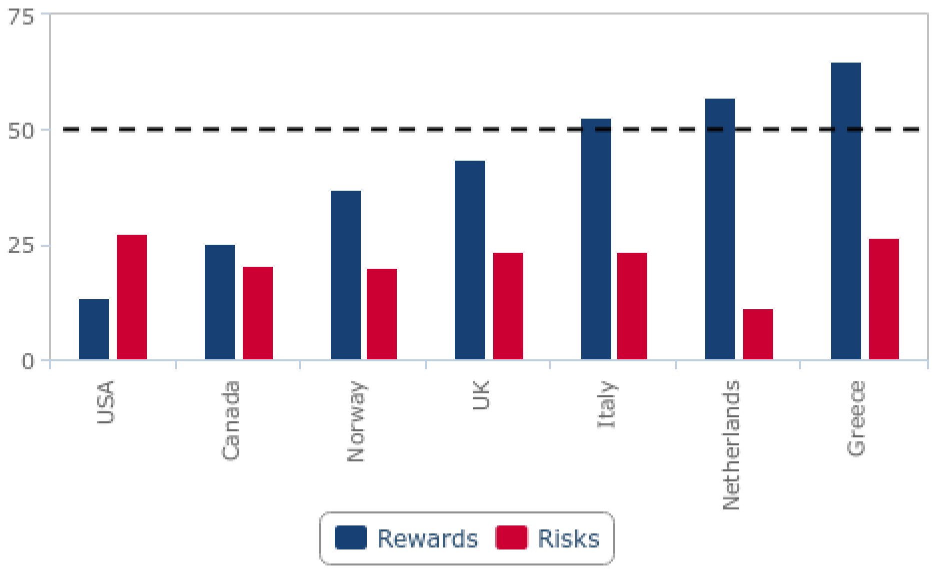
Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

US Remains Leader Supported By Robust Below-Ground Rewards

The US remains at the top of the regional RRI as well as the overall global RRI. The US market substantially outperforms the global average across every indicator in the Industry Rewards and Country Rewards indices. The country's Industry Rewards score of 13.0 is substantially above Canada's score of 22.7; however, sits below scores of a several countries in MENA (UAE - 7.6, Saudi Arabia - 8.7, Iran - 8.2). The US tops the global ranking in the Hydrocarbons Production and see strong oil and gas reserves. However, in the Industry Risks category, it underperforms significantly in royalty rates and to a lesser extent income tax. Fiscal terms are set to deteriorate, as the increased royalty rate was introduced for the leasing on federal lands and waters.

NAWE Strong Performance In Both Rewards In Risks

NAWE - Upstream Country Risk & Reward Score

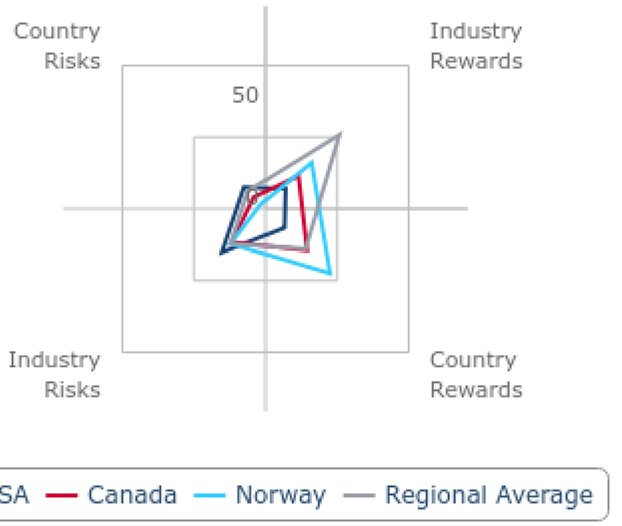


Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

Overall, the outlook for the US upstream is strongly bullish, led by ongoing growth in the US shale sector. While the market has the largest oil and gas production base globally, we forecast weakening oil and gas output growth. We anticipate crude oil and lease condensates to grow by 2.4% y-o-y in 2025, which marks a slowdown from the robust growth of 8.0% and 3.0% y-o-y seen in 2023 and 2024, as companies reach diminishing returns on technological advancements. The drilling activity weakness will also limit upstream growth potential. However, the risks to our forecast are tilted to the upside, given companies' above-expectation performance in 2023, which indicates growing operational efficiencies, and allowed for robust growth in production, in particular across the shale patch, despite weakening new wells drilling. Compared to 2024, we are more bullish in our outlook for natural gas production in the US, on the back of higher Henry Hub prices (currently forecast at USD3.4mnbtu in 2025), and regulatory environment under the Trump administration.

The US Outperforms Regional Averages Except In Industry Risks

US, Canada & NAWE Average - Upstream Country & Industry Risks/Rewards



Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

Strong Production Base Supports Canada And Norway

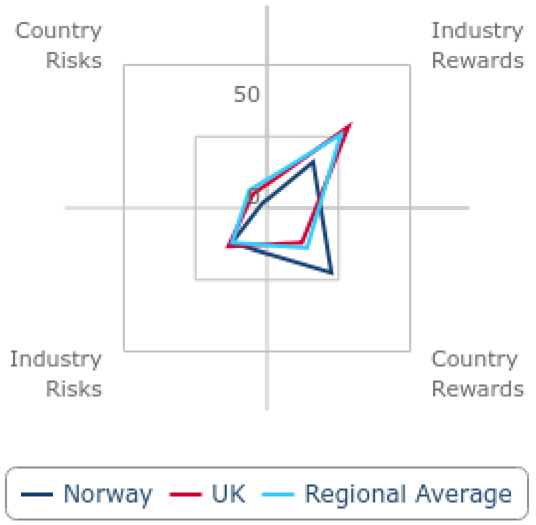
Unchanged from 2024, in second, third and fourth place respectively are Canada, Norway and the UK, the region's other major oil and gas producers. Canada - which ranks second both regionally and globally - shares many of the same characteristics as the US, including long-run political and economic stability, low bureaucratic and legal risks, a secure operating environment and a liberalised market with limited state participation. It also has vast hydrocarbons reserves, particularly of oil, although its discoveries rate is lower than the US, reflecting more limited exploration activities. We have become increasingly bullish in our outlook for Canada's oil production growth over the near term on the back of the completion and the commencement of operations of the TMX pipeline. We expect Canada to increased their oil production by 4.8% y-o-y in 2024 and will see further growth of by 3.1% y-o-y in 2025, which would raise the average crude oil output from to 4.96mn b/d. The role for oil sands has come under increased scrutiny in recent years, due to its high carbon intensity, triggering a number of high profile divestments. That said, emissions intensity is trending downwards and companies are continuing to invest in maximising the lifespan and efficiency of the existing production base. The advent of LNG exports is also supporting stronger prospects for gas production growth, although only one venture - LNG Canada - is currently under development, scheduled for completion in mid-2025. As with the US, the policy and regulatory environment is evolving in line with the country's climate commitments. Notably, Canada has one of the most robust carbon pricing frameworks globally, pledging to increase the price level by CAD15 per year, to reach CAD170/tCO2e by 2030. Canada's position in the index could migrate over time, depending on the evolution of domestic policies and regulations.

Norway ranks third regionally and seventh globally. The market enjoys a large oil and gas reserves base and a high level of legacy production. In 2025, we forecast modest growth in Norway's oil production driven by the ramp up of production at the 220,000b/d Johan Castberg project. We expect total liquids production to reach 2.06mn b/d in 2025, a 3.6% y-o-y increase. Ongoing exploration activities continue to yield new discoveries and production growth prospects are relatively robust, supported by greenfield project additions, improved recovery rates and field tie-ins. The market scores relatively poorly for the state ownership of assets and the diversity of its competitive landscape, due to the dominance of state-owned Equinor in the upstream sector. On the upside, Equinor's decarbonisation strategy is among the most advanced of any globally. Comparatively low carbon intensity and unit cost reductions on new projects render the market well-placed to compete in the future. Norway also benefits from attractive additions above ground, including developed infrastructure and services sectors, a business-friendly investment climate and stable economic and political landscapes.

The UK, which sits in fourth place regionally and 24th place globally, benefits from low state participation and a competitive upstream sector, scoring significantly above Norway on both indicators. However, the UK is disadvantaged by its smaller reserves base, particularly for gas, a lower discoveries rate and forecast production declines over our 10-year forecast period, reflecting a lack of adequate greenfield additions to offset legacy decline rates. Recent years have seen heavy declines in the UK's oil production, which on average declined by around 8.0% y-o-y from 2020-2024, with crude and condensates production falling from 1,029,000b/d in 2019 to an estimated 716,000b/d in 2024. We see these declines being stemmed in the near term, as we forecast the UK's crude production to decline by a much lesser extent of 3.0% y-o-y in 2025. The investment climate in the country has been hampered by increased regulation on the sector introduced by the new Labour administration. The investment environment had already deteriorated since 2022 following the introduction and subsequent increase in windfall tax, which stood at 35% by 2023. This brought the UK’s headline tax rate for the oil and gas sector to 75% - among the highest levels in the world. This has seen its score for Income Tax increase to 98.6.

Norway Outperforming Region Except In Country Rewards

NAWE - Upstream Country & Industry Risks/Rewards



Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

Despite Business-Friendly Environment And Liberalised Market, Italy Sees Low investment

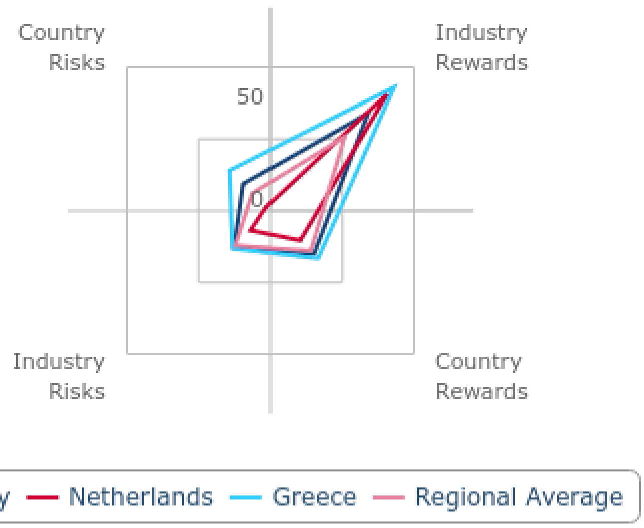
Most markets in Western Europe share some common characteristics, notably low levels of investment risk, undermined by weaker scores for Industry Rewards. Italy and the Netherlands performance is weakened by limited oil and gas reserves, the volume of new discoveries being made, and the size of the hydrocarbons production base. Italy now holds at fifth position in the region and 35th globally, while the Netherlands sit at the respectively sixth and 39th rank. We do not expect these countries to improve their performance significantly given limited ongoing exploration efforts and upstream project pipeline will keep Industry Rewards score relatively low. However, both markets have well-established upstream sectors and profit from comparatively favourable fiscal and licensing terms and attractive operating conditions above ground.

Greece Remains A Regional Outlier

Greece remains at the bottom of the regional index and has remained at 58th place globally. Greece's Industry Rewards score sits at 83.0, which reflects a limited reserves base and very low level of hydrocarbon output, only partially offset by healthy prospects for production growth. That said, new exploration licences offered both onshore and offshore could help to improve the country's position in the index over time. Its competitive landscape is diverse, with only a minor role for the state, but the sector is somewhat underdeveloped, which caps its Country Rewards score. The country's score for Country Risk sits at 28.2, substantially above regional average of 12.3 however below global average of 50.0, making Greece more risky location in the region, but an attractive market in global perspective.

Italy, Netherlands and Greece All Underperform Region In Industry Rewards

NAWE - Upstream Country & Industry Risks/Rewards



Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

NAWE Upstream Risk/Reward Index

	Industry Rewards	Country Rewards	Rewards	Industry Risks	Country Risks	Risks	RRI	Regional Rank	Global Rank
US	13.9	13.2	13.6	30.4	15.0	27.3	15.0	1	1
Canada	22.9	28.9	25.3	23.3	8.1	20.3	24.8	2	3
Norway	32.1	44.9	37.2	24.4	3.2	20.2	35.5	3	10
UK	56.8	24.3	43.8	26.8	9.7	23.4	41.8	4	21
Italy	67.9	30.1	52.8	24.9	18.8	23.6	49.9	5	35
Netherlands	81.3	20.6	57.0	13.6	2.8	11.4	52.4	6	39
Greece	86.0	33.1	64.8	26.3	28.2	26.6	61.0	7	58
Global Average	50.0	50.0	50.0	50.0	50.0	50.0	50.0	~	~
Regional Average	51.5	27.9	42.1	24.2	12.3	21.9	40.1	~	~

Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

NAWE Upstream Industry Rewards

	Oil Reserves	Gas Reserves	Discoveries Rate	Hydrocarbon Production	Hydrocarbon Production Growth	Industry Rewards
US	11.1	4.2	15.3	0.0	38.9	13.9
Canada	4.2	25.0	38.2	5.6	41.7	22.9
Norway	25.0	30.6	25.7	13.9	65.3	32.1
UK	38.9	62.5	50.7	38.9	93.1	56.8
Italy	70.8	79.2	67.4	68.1	54.2	67.9
Netherlands	81.9	75.0	85.4	72.2	91.7	81.3
Greece	88.9	93.1	85.4	94.4	68.1	86.0
Global Average	50.0	50.0	50.0	50.0	50.0	50.0
Regional Average	45.8	52.8	52.6	41.9	64.7	51.5

Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

NAWE Upstream Country Rewards

	State Asset Ownership	Competitive Landscape	Infrastructure Integrity	Country Rewards	Rewards
US	4.9	30.6	4.2	13.2	13.6
Canada	4.9	72.2	9.7	28.9	25.3
Norway	68.1	62.5	4.2	44.9	37.2
UK	4.9	40.3	27.8	24.3	43.8
Italy	21.5	26.4	42.4	30.1	52.8
Netherlands	21.5	12.5	27.8	20.6	57.0
Greece	21.5	9.7	68.1	33.1	64.8
Global Average	50.0	50.0	50.0	50.0	50.0
Regional Average	21.0	36.3	26.3	27.9	42.1

Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

NAWE Upstream Industry Risks

	Royalties	Income Tax	Licence Type	Bureaucratic Environment	Legal Environment Risk	Industry Risks
USA	87.5	54.2	3.5	0.0	6.9	30.4
Canada	94.4	9.0	3.5	4.2	5.6	23.3
Norway	9.0	100.0	3.5	6.9	2.8	24.4
UK	9.0	98.6	15.3	2.8	8.3	26.8
Italy	40.3	45.1	8.3	11.1	19.4	24.9
Netherlands	28.5	33.3	3.5	1.4	1.4	13.6
Greece	54.9	18.1	15.3	16.7	26.4	26.3
Global Average	50.0	50.0	50.0	50.0	50.0	50.0
Regional Average	46.2	51.2	7.5	6.2	10.1	24.2

Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

NAWE Upstream Country Risks

	Long-Term Economic Risk Index	Short-Term Economic Risk Index	Political Risk Index	Operational Risk Index	Country Risks	Risks
US	5.6	23.6	27.8	2.8	15.0	27.3
Canada	11.1	20.8	6.9	1.4	8.1	20.3
Norway	0.0	2.8	0.0	8.3	3.2	20.2
UK	13.9	13.9	11.1	4.2	9.7	23.4
Italy	30.6	37.5	5.6	16.7	18.8	23.6
Netherlands	4.2	4.2	4.2	0.0	2.8	11.4
Greece	37.5	40.3	13.9	31.9	28.2	26.6
Global Average	50.0	50.0	50.0	50.0	50.0	50.0
Regional Average	14.7	20.4	9.9	9.3	12.3	21.9

Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Oil & Gas Risk/Reward Index

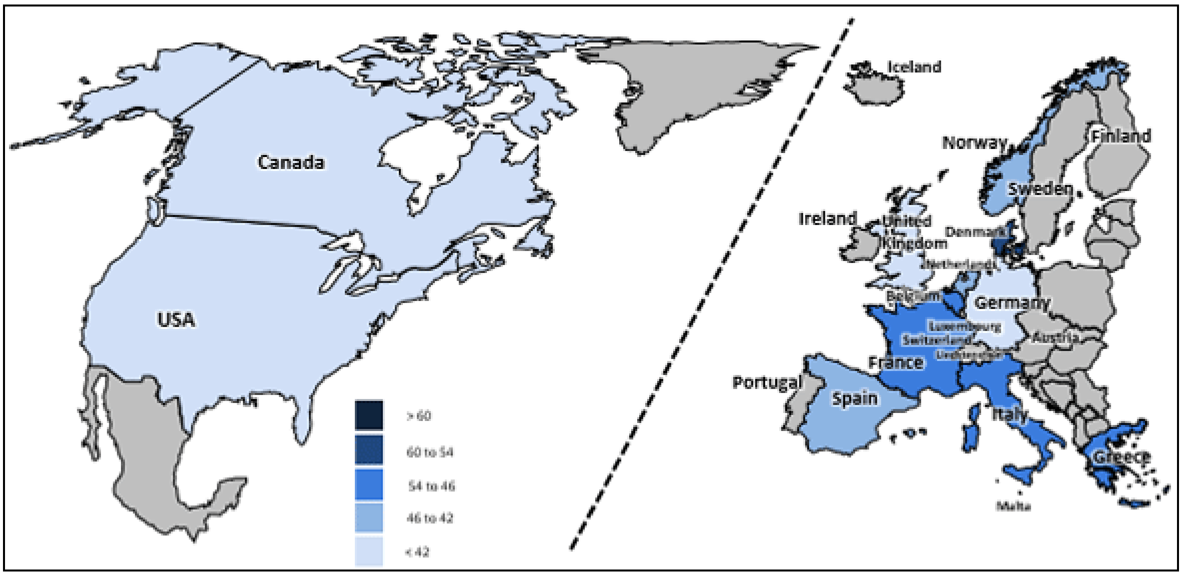
Please Note: *Our Risk/Reward Indices are updated frequently; as a result, scores in this section may not match scores in the rest of the report.*

North American And Western Europe Downstream Oil & Gas Risk/Reward Index

Key View: *The NAWE region performs well in the Downstream Risk/Reward Index, housing top two global markets - the US and Canada. However, the European counterparts vastly underperform the North American peers amid their strong push to electrify their transportation sector. The whole region benefits from low industry and country risks.*

NAWE Houses Largest Fuel Consumers

NAWE - Downstream Risk/Reward Index Heatmap



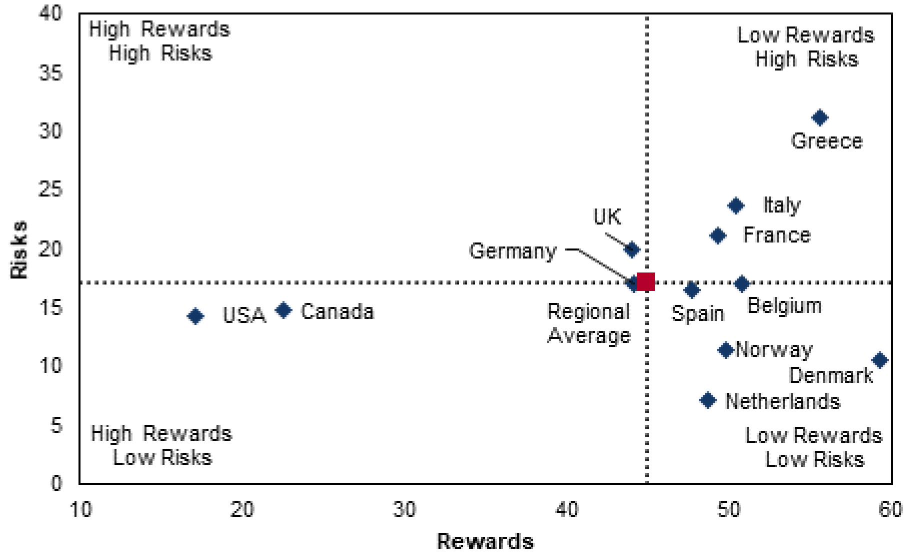
Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

Main Regional Features And Latest Updates

- The NAWE region tops the Downstream Risk/Reward Index (RRI) with the US and Canada holding respectively first and second positions. The NAWE Downstream RRI score sits at 42.1 out of 100, outperforming the global average of 50.0.
- In terms of risks, the region performs well, with Industry Risks sitting at 17.4 and Country Risks at 16.8. The Industry Risk scores are low as the region sees limited logistics risks, scored at 14.1, with only limited fuel subsidies present in the region (score of 20.6).
- The country risks are also very limited for the region, which benefits from good operational standards and limited political risk. The Short-Term Economic Risk is scored at 25.3, weakened by the slowing real GDP growth for the developed economies. At the same time, the Long-Term Economic Risk scores at 18.7, substantially better than the global average.
- The region outperforms the global average in Industry Rewards, benefitting from robust refining base, high utilisation rate and new infrastructure. However, this category score is weakened by the fuel demand growth component, as we expect developed markets across North America and Europe to continue phasing out internal combustion engines, while switching to the alternatives like electric vehicles.
- The Country Rewards score for the region sits at 47.5, supported by attractive market composition framework with limited state asset ownership. The score is weakened by population growth, which is now scored at 74.3.
- The US and Canada sit at the top of the Downstream RRI ranking, scoring respectively 16.9 and 21.8. They are followed by European countries, led by the UK and Germany, with the scores of respectively 41.4 and 41.6.
- Denmark (54.4) and Greece (53.2) close the list, scoring above the global average of 50.0, which indicates heightened risks, mostly down to low populations and crude production prospects.

North American Score Eclipse European Markets

NAWE - Downstream RRI Snapshot



Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

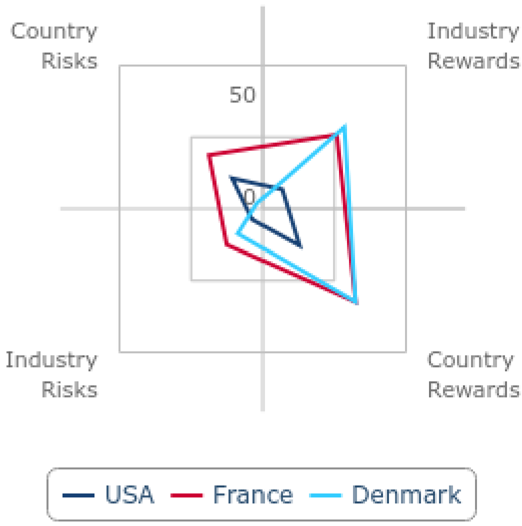
NAWE Slightly Outperforms Global Average In Industry Rewards Owing To US And Canada

The NAWE downstream market houses some of the largest consumers and producers of fuels in the world. Both the US and Canada benefit from robust refining capacity, high utilisation rates and healthy domestic and regional demand. Their refining fleet is relatively new and both countries are large exporters of crude oil. However, both markets are expected to accelerate their transition to electrification of transport, with growing share of electric vehicles in the total fleet and constrains on use of internal combustion engines. Nevertheless, the US and Canada remain the most attractive downstream markets in the NAWE region and globally. scoring respectively 16.9 and 21.8.

European counterparts see substantially lower scores for domestic fuel demand, which is weakened by the deployment of EVs and tightening standards for motor fuels in a number of countries in Europe. As a result, the region scores poorly in the Fuel Demand Growth category. The UK, Germany, the Netherlands and Norway see Industry Rewards scores ranging 40.0 to 50.0, while the rest of European markets on the list score above global average which indicates limited benefits. Their scores are also weakened by their theoretical dependence on fuel imports, except for Norway.

Northern American Markets Outperform European Counterparts

NAWE - Downstream RRI, By Component



Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

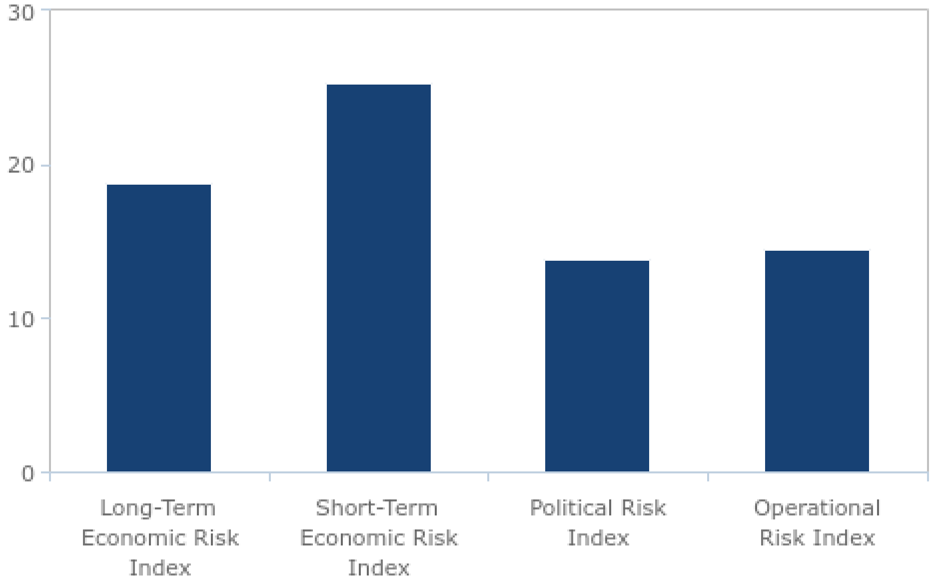
Relatively smaller population bases in European countries weigh on the Country Rewards scores, coupled with a bleak outlook for population growth. Greece's score of 92.3 is weakened by our bleak outlook for the market's population growth. The whole region underperforms in population growth, scoring 74.3, substantially above the global average of 50.0. However, the region performs well in the State Asset Ownership category, given the dominance of private facilities. Overall, the Rewards score for NAWE sits at 44.9 supported by Industry Rewards score of 43.8.

Strong Performance In Industry Risks Supports High Global Ranks

The NAWE region sees only limited Industry Risks, which are scored at 17.4 for the whole region. Markets in both North America and Europe see little logistics risk, with a very low regional score of 14.1 for this category. With a score of 35.2, Greece sees the weakest score in this category; however, it still manages to substantially outperform the global average. In addition, all markets in NAWE operate in the market price regime and the governments refrain from intervening in the fuel price market. This elevates the regional score for the Industry Risks.

Strong Performance In Country Risks

NAWE - Downstream Country Risk By Component



Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

The NAWE region outperforms the other regions very strongly in the Country Risks category as the region contains some of the largest economies and most stable political systems in the world. The Country Risks category performs best from all index components, scoring 16.8. While the NAWE region sees somewhat heightened Short-Term Economic Risks, at 25.3, they remain well below the global average. At the same time, the score for Political Risk is low for the region, sitting at 13.8.

NAWE Downstream Risk/Reward Index

	Industry Rewards	Country Rewards	Rewards	Industry Risks	Country Risks	Risks	RRI	Regional Rank	Global Rank
US	13.5	25.6	17.1	7.4	21.2	14.3	16.9	1	1
Canada	18.6	31.9	22.6	15.7	13.9	14.8	21.8	2	2
Germany	45.4	41.0	44.1	22.3	11.6	16.9	41.4	3	20
UK	48.3	34.1	44.0	23.9	16.0	20.0	41.6	4	22
Netherlands	46.0	54.9	48.7	8.5	5.7	7.1	44.5	5	29
Spain	49.5	43.2	47.6	14.0	19.1	16.6	44.5	6	30
Norway	41.1	70.1	49.8	17.9	4.9	11.4	45.9	7	35
France	52.8	40.8	49.2	25.0	17.4	21.2	46.4	8	36
Belgium	51.1	49.8	50.7	11.8	22.3	17.0	47.3	9	42
Italy	50.9	49.1	50.4	19.5	27.8	23.7	47.7	10	44
Greece	51.6	64.8	55.6	25.0	37.4	31.2	53.2	11	51
Denmark	56.9	64.7	59.2	17.3	3.9	10.6	54.4	12	53
Global Average	50.0	50.0	50.0	50.0	50.0	50.0	50.0	~	~
Regional Average	43.8	47.5	44.9	17.4	16.8	17.1	42.1	~	~

Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

NAWE Downstream Industry Rewards

	Refining Capacity	Utilisation Rates	Domestic Fuel Demand	Fuel Demand Growth	Regional Fuel Demand	Life Span Of Infrastructure	Theoretical Net Crude Exports	Industry Rewards
US	1.1	2.2	0.0	83.5	0.5	2.7	4.4	13.5
Canada	11.0	8.8	8.8	92.3	0.5	6.6	2.2	18.6
UK	12.1	13.2	9.9	89.0	48.9	49.5	95.6	45.4
Germany	27.5	31.9	16.5	98.9	48.9	34.1	80.2	48.3
Netherlands	19.8	44.0	25.3	71.4	48.9	20.3	92.3	46.0
Spain	14.3	36.3	17.6	86.8	48.9	49.5	93.4	49.5
France	51.6	24.2	57.1	95.1	48.9	2.7	7.7	41.1
Norway	25.3	48.4	15.4	93.4	48.9	49.5	89.0	52.8
Italy	33.0	15.4	35.2	91.2	48.9	49.5	84.6	51.1
Belgium	13.2	46.2	22.0	97.8	48.9	34.1	94.5	50.9
Greece	39.6	1.1	44.0	76.9	48.9	65.4	85.7	51.6
Denmark	60.4	39.6	60.4	85.7	48.9	38.5	64.8	56.9
Global Average	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Regional Average	25.7	25.9	26.0	88.5	40.8	33.5	66.2	43.8

Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

NAWE Downstream Country Rewards

	State Asset Ownership	Population	Population Growth	Country Rewards	Rewards
US	8.8	2.2	65.9	25.6	17.1
Canada	8.8	37.4	49.5	31.9	22.6
UK	22.0	17.6	83.5	41.0	44.1
Germany	8.8	20.9	72.5	34.1	44.0
Netherlands	30.8	60.4	73.6	54.9	48.7
Spain	8.8	34.1	86.8	43.2	47.6
France	73.1	82.4	54.9	70.1	49.8
Norway	23.6	22.0	76.9	40.8	49.2
Italy	8.8	65.9	74.7	49.8	50.7
Belgium	30.8	25.3	91.2	49.1	50.4
Greece	30.8	71.4	92.3	64.8	55.6
Denmark	43.4	81.3	69.2	64.7	59.2
Global Average	50.0	50.0	50.0	50.0	50.0
Regional Average	24.9	43.4	74.3	47.5	44.9

Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

NAWE Downstream Industry Risk

	Logistics Risk	Fuel Subsidies	Industry Risks
US	0.0	14.8	7.4
Canada	16.5	14.8	15.7
UK	6.6	37.9	22.3
Germany	9.9	37.9	23.9
Netherlands	2.2	14.8	8.5
Spain	13.2	14.8	14.0
France	20.9	14.8	17.9
Norway	12.1	37.9	25.0
Italy	8.8	14.8	11.8
Belgium	24.2	14.8	19.5
Greece	35.2	14.8	25.0
Denmark	19.8	14.8	17.3
Global Average	50.0	50.0	50.0
Regional Average	14.1	20.6	17.4

Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

NAWE Downstream Country Risks

	Long-Term Economic Risk Index	Short-Term Economic Risk Index	Political Risk Index	Operational Risk Index	Country Risks	Risks
US	9.9	31.9	38.5	4.4	21.2	14.3
Canada	18.7	29.7	14.3	3.3	13.9	14.8
UK	4.4	15.9	9.9	14.8	11.6	16.9
Germany	20.9	20.3	19.8	7.7	16.0	20.0
Netherlands	8.8	5.5	8.8	1.1	5.7	7.1
Spain	35.2	22.5	12.1	16.5	19.1	16.6
France	0.0	3.3	1.1	12.1	4.9	11.4
Norway	14.3	28.6	11.0	19.8	17.4	21.2
Italy	23.6	44.0	15.4	17.6	22.3	17.0
Belgium	39.6	46.2	13.2	27.5	27.8	23.7
Greece	46.2	48.4	22.0	42.9	37.4	31.2
Denmark	3.3	7.1	0.0	6.6	3.9	10.6
Global average	50.0	50.0	50.0	50.0	50.0	50.0
Regional average	18.7	25.3	13.8	14.5	16.8	17.1

Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Oil & Gas Risk/Reward Index

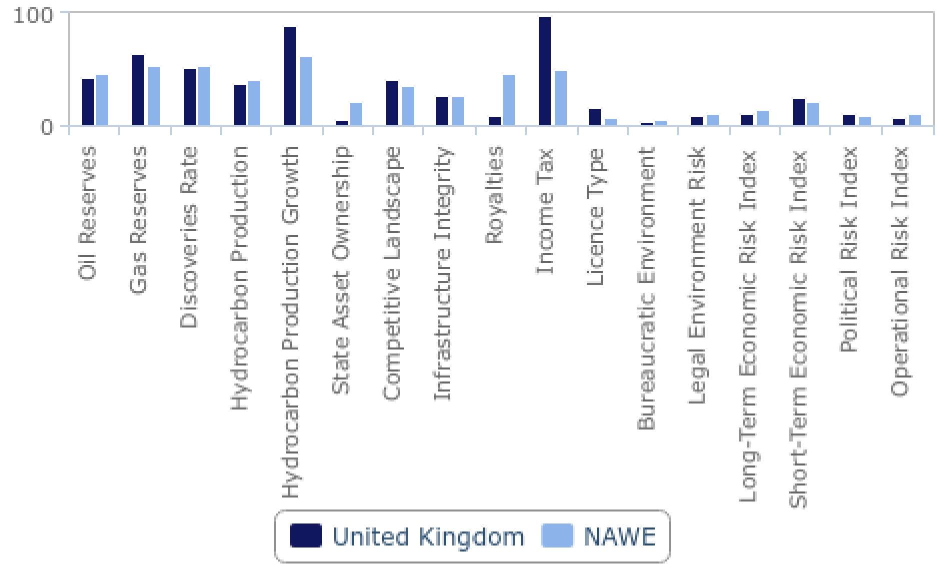
Please Note: *Our Risk/Reward Indices are updated frequently; as a result, scores in this section may not match scores in the rest of the report.*

United Kingdom Upstream Risk/Reward Index

Key View: *The UK has seen its ranking recently decline in our Upstream Risk/Reward Index. This has been driven by recent tax increases impacting the country's hydrocarbon production and hydrocarbon production outlook. Mature North Sea assets, a low discoveries rate and limited potential for maintaining production levels weigh on the UK's overall score. We also note that the Labour Party victory in the July 2024 General Elections will likely further impact the country's Industry and Country Rewards scores, due to proposed tax increases and a possible end to new exploration and production licences.*

RRI Matrix Breakdown

UK & NAWE - Upstream Risk/Reward Index By Component



Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Risk/Reward Index

Global And Regional Ranks

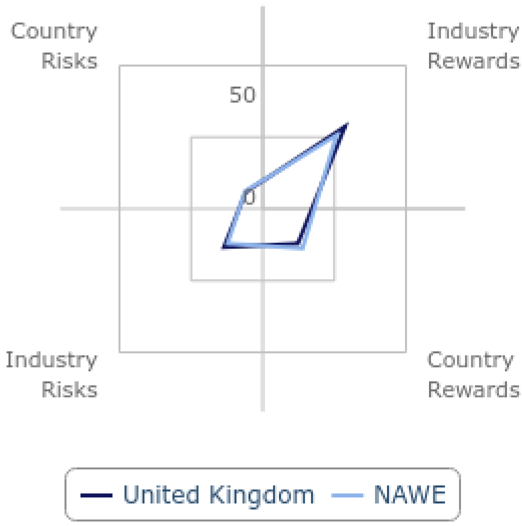
- Regional rank (out of 7): 4th
- Global rank (out of 72): 22nd

Key Features And Latest Updates

- This quarter, the UK's global and regional position remains stable, scoring fourth regionally and 22nd globally in our Upstream Risk/Reward Index rankings.
- Recent downward revisions were a result of the recent tax increases impacting the country's hydrocarbon production and hydrocarbon production outlook. Moreover, we also note that the Labour Party victory in the July 2024 General Elections will likely further impact the country's Industry and Country Rewards scores, due to proposed tax increases and a possible end to new exploration and production licences.
- The UK's score for income tax has been further revised down in light of the government's decision to raise the Energy Profits Levy from 25% to 35% as part of the latest autumn budget. This has raised the headline tax rate for the country's oil and gas industry to 75% - among the highest levels in the world. This could rise to 78% should a further increase on the EPL go through, as proposed by the new government.
- Mature North Sea assets, a low discoveries rate and limited potential for maintaining production levels weigh on the UK's overall score.

A Strong Regional And Global Performer

UK & NAWE - Upstream Country & Industry Risks/Rewards



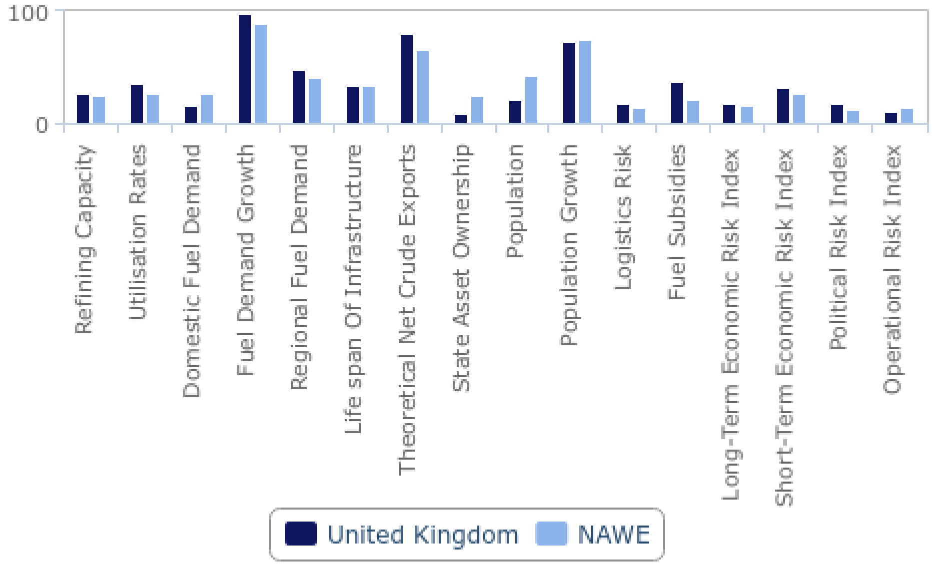
Note: Scores out of 100; lower score = more attractive market. Source: BMI Upstream Risk/Reward Index

United Kingdom Downstream Risk/Reward Index

Key View: *The UK has retained the same position both globally and regionally in our Downstream Risk/Reward Index. The UK's outlook is boosted by capacity and utilisation rates. However, as in many other European markets, an unfavourable demographics, and regional declines in demand for fuels impact its overall Downstream RRI scores.*

RRI Matrix Breakdown

UK & NAWE - Downstream Risk/Reward Index By Component



Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Risk/Reward Index

Global And Regional Ranks

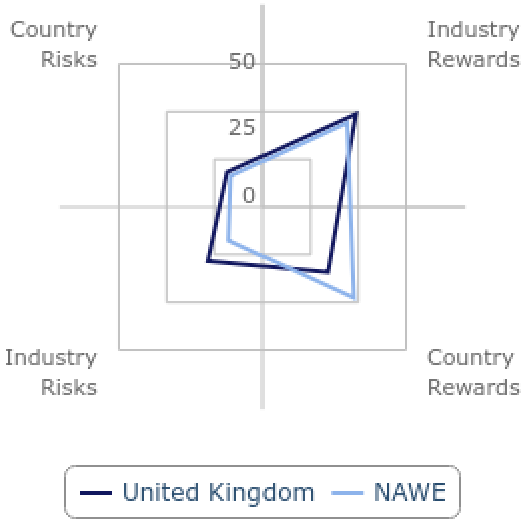
- Regional rank (out of 12): 3rd
- Global rank (out of 92): 24th

Key Features And Latest Updates

- This quarter, the UK has retained the same position both regionally (third) and globally (24th) in our Downstream Risk/Reward Index.
- The country's score for utilisation rates has improved slightly over the last quarter, as elevated refining margins have seen an increase in output.
- The UK continues to benefit from high refining capacity and utilisation rates that are above the regional average.
- Despite a healthy-sized domestic demand market, the UK, like several other regional peers, suffers from a particularly weak demand growth outlook for refined fuels. This is primarily due to increasing vehicle efficiency, a rising EV fleet, in addition to a weak economic outlook for the British economy in the medium term.

Favourable Risk Metrics Outweigh Weaker Industry Rewards

UK & NAWE - Downstream Country & Industry Risks/Rewards



Note: Scores out of 100; lower score = more attractive market. Source: BMI Downstream Risk/Reward Index

Market Overview

Oil & Gas Market Overview

Regulatory Structure

- **Key Legislation:** The key legislation governing the oil and gas upstream sector is the Petroleum Act 1998. Under the Petroleum Act, all rights to petroleum are vested in the Crown.
- **Relevant Government Ministries:** The Secretary of State for Energy and Climate Change and the Department for Business, Energy and Industrial Strategy (BEIS) are the main agencies for the regulation of the development of the UK's oil and gas resources. Under the Petroleum Act, BEIS issues offshore production licences of different contract lengths with the following requirements: exploration, appraisal and development and production. These licences are given out during licensing rounds. The Health and Safety Executive is responsible for offshore safety.
- **Regulatory Bodies:** As of March 21 2022, the independent regulator (previously known as the Oil and Gas Authority) has officially been renamed as the North Sea Transition Authority (NSTA). This change of name is intended to reflect the evolution of the organisation's role in which it is playing an important part in ensuring the energy transition of the UK North Sea. The NSTA is still responsible for the licensing and regulatory oversight functions which had been performed by the Department of Energy and Climate Change until 2015. However, its responsibilities have been expanded to include the monitoring of emissions and the licensing of carbon storage facilities.
- **NOC:** The UK no longer has an NOC. Developments are carried out entirely by private companies and foreign state-owned companies under licences granted by the secretary of state.

Fiscal Regime

New Labour Policies Set To Further Negatively Impact UK O&G Sector

The new UK Labour government has proposed a series of additional changes to the fiscal regime covering production in the UK and the UK Continental Shelf. The government of Prime Minister Keir Starmer will present its first budget in October 2024. However, as per its election manifesto, these include:

- Extend the Energy Profits Levy (EPL) from March 2028 to March 2030;
- Increase the EPL by 3% from November 2024 onwards, bringing the marginal tax rate to 78%, in line with Norway;
- 'Close the loopholes' in the EPL and remove 'generous investment allowances';
- Maintain the Energy Security Investment Mechanism (ESIM);
- And end licensing for the exploration of new oil and gas fields.

These changes apply specifically to the profits earned on the production of oil and gas either onshore UK or in the UK Continental Shelf (UKCS) and so the new legislation will not affect the international operations of firms operating in the UK. Nevertheless, it will likely significantly impact on company cash flows, while further increasing fiscal uncertainties.

The current fiscal regime comprises a 30% corporation tax, a 10% supplementary charge and a 35% EPL. The profits these apply to are ringfenced and so the various taxes cannot be offset by losses elsewhere in the business. Labour policies will increase the fiscal burden on companies operating in the UK, straining profitability in the O&G sector. The level of government take is already amongst the highest in the world and arguably at odds with the country's mature asset base and declining output.

Furthermore, in its manifesto, Labour also pledged to close the 'loopholes' in the EPL. Although it is not entirely clear what this entails, it seems likely that they intend to end the current investment expenditure uplift, which stands at 80% for decarbonisation investments and 29% for other expenditures. Qualifying expenses include capital spending as well as certain operating costs and lease payments. This is highly significant as it will impact on net revenues, not just profits. Any implicit tax on revenues will be poorly received by the industry and will likely act as a strong disincentive for investment. UK-focused players are already voicing concerns that under Labour's new fiscal regime the capital costs of new projects may be impossible to recoup. While the new policies will align the UK with Norway's marginal tax rate, it should be noted that Norway also offers tax rebates set at 100% of a company's capital expenditures, which Labour seemingly will not. This dramatically alters the calculus for investment.

Producers are also grappling with elevated uncertainties. Given the long lead times and extended payback periods that typify the Oil & Gas sector, forward transparency is crucial in fostering investment. Repeated changes in the fiscal terms governing upstream projects in the UK over recent years have done much to damage investor sentiment. The ESIM was designed to combat this – to 'give the oil and gas sector certainty to raise capital and invest in new and existing projects'. It exempts companies from the EPL when oil and gas prices concurrently fall below the historical 20-year average for two consecutive quarters; that is, USD71.4/bbl for Brent and GBP0.54/therm for NBP. However, given that this scenario seems unlikely to occur in the foreseeable future, the policy has done little to bolster confidence.

Deteriorating fiscal terms and uncertainty over future policies governing the oil and gas sector will likely deter investors. The UK was already struggling to compete for capital on a global scale. Against the backdrop of the broader energy transition, the capital allocation process is highly competitive, and companies are keeping a laser-like focus on commercial breakevens. On average, UK O&G projects are relatively costly and will become more so under a Labour government.

Future exploration posed upside risk to our outlook, but Labour's licensing ban will have put paid to this. Admittedly, mature acreage tends not to yield major new discoveries. However, production can often be supported via near-field exploration and satellite developments tied into existing infrastructure. The ban may curb the economic lifespan of existing reservoirs and lead to the earlier decommissioning of existing platforms and pipelines.

2022-2023 Windfall Tax Already Hurt Investment Environment Prior To Labour-Win

Former Prime Minister Sunak's government had already imposed in May 2022 a windfall tax (called the Energy Profits Levy) on North Sea oil and gas industry, as companies' earnings increased significantly alongside fuel prices following Russia's invasion of Ukraine in early 2022. By late 2022, the levy was at a new 35.0% surcharge on profits made from the oil & gas sector. This was on top of the 40.0% tax already paid by the industry. In order to offset the levy, a new investment allowance was also introduced, with the goal of incentivising re-investment into the UK. This raised the effective tax relief on money invested from GBP46 to GBP91.40 per GBP100 invested.

We had already noted the decision to extend the imposition of the levy from 2025 until March 2028 would be unlikely to instill confidence within the industry, given the ease with which the government has extended the original timeline. The market had originally priced in a one-off windfall tax, but this has transformed into a multi-year proposaln significantly changing the outlook for industry investors. For example, following the proposed push-back in the date, BP stated that because the levy was not a one-off measure, it would need to assess the impact of the levy and tax relief on its North Sea renewable and low carbon investment plans, placing GBP18.0bn of investment at risk. This is unsurprising, given that oil and gas companies plan spending and investments for the long term and desire stability in fiscal regimes.

In addition, we also noted that the effect of the tax to be felt mostly by UK independents, rather than on the majors such as BP and Shell, despite specific restrictions on offsetting previous years' losses against the tax bill. Expensive decommissioning costs have allowed larger majors with ageing asset bases to negate most or all of their tax bill in recent years, often leading to negative tax bills that can be carried over. The windfall tax specifically blocks the use of previous years negative tax bills carried over to offset the tax impact, which most greatly impacts the majors. Due to their diversification, the majors will still be less impacted by the tax than UK independents.

The new Labour government's further extension and further increase of the tax EPL rates will further damage the outlook for the UK's exploration and production sector (*see above*).

A Significant Fiscal Upheaval

	Ring Fence Corporation Tax*	Supplementary Charge	Petroleum Revenue Tax**	Energy Profits Levy	Total Marginal Tax Rates
Description	Tax on ring-fenced profits.	Additional tax on profit introduced in 2011 in the context of high oil prices.	Field-based tax charged on profits arising from oil and gas production from field given development consent before 1993.	The levy is a new 25% surcharge on profits made from the oil & gas sector	na
Previous fiscal regime	30%	20%	35%	0%	40% across all fields
New fiscal regime	30%	10%	0%	35%	75% for all fields

*Note: *Profits from oil and gas exploration and production are subject to the ring-fence rate; refining and marketing subject to non-ring-fence rate. **For fields that received development consent before March 16 1993. na = not available/applicable. Source: BMI*

Licensing Regime

UK Licensing Regime

Main Contract Type	State Participation	Local Content Requirement	Domestic Supply Requirement	Stabilisation Clause	Arbitration
Concessions	None	None	None	na	Arbitration is by a single arbitrator appointed by the Secretary of State and the licensee Ratified New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards (1975) Ratified Convention on the Settlement of Investment Disputes between States and Nationals of Other State (1966).

Note: na = not available. Sources: International Comparative Legal Guides, Ernst & Young, BMI

Recent Licensing Rounds

33rd Offshore Licensing Round (2022-2023)

The 33rd Licensing Round opened in October 2022, with more than 900 Blocks made available for bidding. Applications closed in January 2023, with 115 bids coming in from 76 companies.

We believe that this most recent licensing round is likely to have a negligible effect on exploration activity in the UK north sea and therefore fail to reverse the sharp downward trend in exploration that has occurred in recent years. In May 2024, the North Sea Transition Authority completed the final tranche of the licensing round, offering companies 31 permits. That followed 27 licenses offered in October 2023 and 24 in January 2024.

32nd Offshore Licensing Round (2019/2020)

In July 2019, the 32nd UK Offshore Licensing Round officially opened. A total of 768 blocks or part-blocks on offer across the main producing areas of the UK Continental Shelf, with acreage on offer in the Central North Sea, Northern North Sea, Southern North Sea and the West of Shetlands. On September 3 2020, the Oil and Gas Authority (OGA) offered for award 113 licence areas over 260 blocks or part-blocks to 65 companies in the 32nd Offshore Licencing Round. The winners include a mix of majors such as BP and Shell as well as smaller independents such as Chrysaor.

31st Offshore Licensing Round (2018)

A total of 1,766 blocks over an area of 370,000sq km of open acreage were offered across the West of Scotland, the East Shetland Platform, the Mid North Sea High, South West Britain and parts of the English Channel. In June 2019, the OGA offered for award 37 licence areas over 141 blocks or part-blocks to 30 companies in the 31st Offshore Licensing Round. These successful awards act as a strong platform for future exploration and production in frontier areas of the UK Continental Shelf.

A number of proposed new work programmes have been secured in this round, including new shoot seismic acquisition, with two licences progressing straight to field development planning (second term licences).

Oil & Gas Infrastructure

Oil Refineries

Oil Refineries United Kingdom

Refinery	Capacity ('000b/d)	Owner	Built	Status
Fawley	275	ExxonMobil	1951	Operational
Humber	221	Phillips 66	1969	Operational
Pembroke	210	Valero Energy (Chevron sold refinery in 2011)	1964	Operational
Lindsey	110	Prax group (TotalEnergies sold refinery in 2021)	1968	Operational. Downsized by 110,000b/d in 2017
Stanlow	205	Essar Oil UK (sold by Shell)	1923	Operational. Downsized by 100,000b/d in 2014
Grangemouth	150	Petroineos (JV Ineos and Petrochina)	1924	Closure and conversion into fuels import terminal in 2025.
Teeside	117	Petroplus	na	Mothballed in 2009
Coryton	220	Petroplus	1953	Mothballed in 2012. Turned into oil import and distribution terminal.
Milford Haven	135	Murphy Oil	1974	Mothballed in 2014
Isle of Grain	110	BP	1952	Mothballed in 1982
Total operating capacity	**1,171**			

na = not available/applicable. Source: EIA, IEA, company data, BMI

The UK currently has six major refineries with a total capacity of 1.17mn b/d, according to our Downstream Projects Database. The industry is sophisticated and meets all current and planned environmental requirements.

Oil Storage Facilities

As a member of the International Energy Agency (IEA) and the EU, the UK is required to hold emergency stocks equivalent to 67.5 days of consumption. The government meets this obligation by directing oil companies to hold stocks rather than by maintaining a strategic petroleum reserve.

Oil Storage Facilities

Oil Terminals/Ports

The Sullom Voe oil terminal in Shetland, operated by BP, handles output from more than 24 North Sea platforms, which it receives via the Brent and Ninian pipeline systems. Other major terminals in Scotland include St. Fergus (TotalEnergies), Cruden Bay (BP), Flotta (Talisman Energy) and Nigg Bay (Talisman Energy), while the north east and east of England has Teesside, Bacton, Easington and the Isle of Grain. Southampton is the major port and terminal on the south coast of England.

Oil Pipelines

An elaborate network of pipelines transports oil from the North Sea to terminals in Scotland and the north of England. According to the IEA, BP has two major pipelines: the 177km, 36-inch Forties-Cruden Bay pipeline and a 177km line that connects the Ninian system to Sullom Voe on Shetland. TotalEnergies has a 241km pipeline connecting the Bruce and Forties fields to Cruden Bay as well as a second pipeline that runs 209km from the Piper system to Flotta on Orkney. Shell and Exxon jointly run a 150km link between the Cormorant oil field and Sullom Voe. Talisman Energy has a 60km pipeline between the Beatrice field and the Nigg Bay terminal. Numerous smaller pipelines link other platforms to this network.

There are a small number of onshore oil pipelines of which the most significant runs 145km underground from the UK's (and Western Europe's) largest onshore field, Wytch Farm in Dorset, to the refinery at Fawley and the export terminal in Southampton. The route is operated by BP.

There is one international crude pipeline, Norpipe, which is capable of transporting 900,000b/d of oil from the Ekofisk fields in the Norwegian North Sea to the Teesside refinery and terminal.

There is one major oil products pipeline, the 650km-long UK Oil Pipeline, that connects refineries on the River Thames and the River Mersey to inland distribution terminals. The route is administered and operated by the Shell/BP-owned British Pipeline Agency. The route transports 7.5mtpa of mixed products (two grades of gasoline, two of kerosene and two of diesel/gasoil) to major terminals at Buncefield and Kingsbury with spurs to Northampton and Nottingham.

LNG Terminals

The UK currently has three operating LNG terminals: Grain LNG on the Isle of Grain in Kent, owned by the National Grid; and South Hook and Dragon, both located at Milford Haven in Wales.

Grain (active): Grain's capacity has seen three phases of expansion since it became operational in 2005. In the first phase the terminal had a capacity of 3.3mtpa or 4.6bcm, which BP and Sonatrach acquired the rights to for 20 years. In December 2008 the second phase of expansion was completed, increasing Grain's capacity to 9.8mtpa or 13.5bcm. The additional 6.5mtpa (9.6bcm) capacity was contracted to GDF Suez, Centrica and Sonatrach. The completion of the third phase in late 2010 added another 5.0mtpa (6.9bcm) bringing its total import capacity to about 20bcm (20% of annual UK gas demand). E.ON Ruhrgas, Iberdrola and Centrica acquired the rights to this additional LNG capacity at Grain. In October 2020, Qatar Petroleum announced a 25-year deal in which it has agreed to take up to 7.2mtpa (roughly 10bcm) of regasification capacity and LNG storage from 2025 through to 2050.

In early 2024, Grain LNG signed a 10-year deal with Sonatrach to extend the Algerian company's long-term storage and redelivery capacity at the Grain LNG import terminal beyond January 2029. The deal is for 3.0mtpa of LNG import capacity and it is the first to be announced under Grain LNG's competitive auction process which launched in September 2023 for 9.0mtpa of capacity. The terminal (located in Kent) is currently being expanded to store and deliver enough gas to meet up to 33% of British gas demand.

South Hook (active): The South Hook LNG regasification terminal, located at Milford Haven in southwest Wales, received its first LNG delivery in March 2009. South Hook is owned by Qatar Petroleum (67.5%), ExxonMobil (24.14%) and TotalEnergies (8.35%) and it sources LNG primarily from their joint production in Qatar. Following first-phase development the terminal had a processing capacity of 7.5mtpa of LNG equivalent to 10.34bcm of gas. In April 2010, South Hook LNG Terminal Company completed the construction and commissioning of the second and final phase of the South Hook LNG plant. The terminal now has 15.6mtpa of LNG processing capacity and is capable of supplying 21bcm of gas annually to the UK National Transmission System (about 20% of the country's gas demand). In November 2022, Qatar announced plans to invest several hundred million British pounds in order to to increase the capacity of the terminal to 20mtpa. The expansion is expected to be completed by H225.

Dragon (active): Dragon LNG, located at Milford Haven, was brought onstream in July 2009. It is supplied mainly with LNG from Qatargas II. Dragon is owned by Shell (50.0%), Petronas (30.0%) and 4Gas (20.0%). It had a start-up capacity of 6bcm, which could later be increased to 9bcm, according to 4Gas. The two terminals regasify LNG which is then supplied to the National Gas Transmission system.

Trafigura confirmed in 2022 and 2023 that it is looking to re-open its Teeside LNG facility, which it closed in 2015 due to a lack of activity. The re-opening signals the growing appetite for gas imports in the UK, with LNG cargoes becoming increasingly competitive with pipeline imports as hub-linked exports from the US grow in availability. We previously highlighted that the UK will become increasingly dependent on gas imports as domestic production declines and gas consumption in the domestic power market rises.

Gas Storage Facilities

The UK currently has nine gas storage facilities in operation. There are also two new fields currently under construction. In the past, the availability of domestic gas supplies from the UK Continental Shelf (UKCS) had meant that the development of large underground storage capacity to maintain a secure gas supply in the UK had arguably not been necessary. The UK's current gas storage facilities were therefore not designed to provide long-term strategic storage in the event of prolonged supply disruption.

Due to significant gas supply disruptions to Europe emanating from the war in Ukraine, and the heightened geopolitical risk of potential damage to pipelines such as the Langeled pipeline supplying gas from Norway to the UK, this strategic calculus has completely changed. The new UK energy strategy released in 2022 strongly emphasised the urgency of strengthening energy independence, and significant transformations are underway to increasing the UK's gas storage capacity, which is significantly lower relative to its European peers. In this regard, the most important recent development is the approval given by the North Sea Transition Authority to Centrica in order to enable the resumption of operations at the Rough Field gas storage site.

In June 2023, Centrica announced the completion of expansion work at the Rough gas storage facility, almost doubling its total storage capacity from 0.8bcm previously to 1.5bcm. Although the expansion is intended to strengthen the UK's energy security, it will do little in this regard, given that the UK's total gas storage capacity still remains scarce, especially relative to regional peers such as Germany and Italy. In January 2025, Centrica has warned that the UK's gas storage levels are concerningly low. In response Centrica claimed they would invest GBP 20bn to upgrade this facility. They are looking to seeking support from the government through a price cap and floor mechanism to make this viable. No finalized timeline or plan has been created.

Gas Storage Facilities

Gas Storage Facilities

Name	Operator	Status	Capacity (bcm)	Flow Rate (mcm/d)	Planned Expansion (bcm)
Rough	Centrica	In operation	1.5	43.0	na
Hornsea	SSE	In operation	0.30	18.0	na
Hatfield Moor	Scottish Power	In operation	0.10	2.0	na
Holehouse Farm	EDF Energy	In operation	0.10	8.0	na
Humbly Grove	Star Energy	In operation	0.30	7.0	na
Aldbrough	SSE/Equinor	In operation	0.17	40.0	0.15
Holford	E.ON	In operation	0.06	22.0	0.16
LNG	National Grid	In operation	0.18	32.0	na
Stublach	Storengy UK	Under construction	na	na	0.40
Hill Top Farm	EDF Energy	Under construction	na	na	0.10

na = not available/applicable. Source: BMI

Gas Pipelines

Gas Pipelines

Four major pipeline systems transport gas from the North Sea to coastal terminals, according to the IEA. These are the Shearwater-Elgin pipeline, operated by TotalEnergies, which runs to Bacton in Norfolk; the Exxon-operated Scottish Area Gas Evacuation, which runs 322km to St. Fergu;, the 402km Central Area Transmission System, which is operated by BP and connects the Graben area of the UKCS to Teesside; and the Shell-operated Far North Liquids and Gas System that links the Brent fields to St. Fergus. Once onshore, gas is transmitted by National Grid Transco, which owns a 6,759km pipeline network around the UK.

Internationally, the Langeled pipeline system, completed over 2006-2007, links Norway's Ormen Lange field to the Easington gas terminal in northeast England. At 1,207km, it is the longest subsea pipeline in the world with a capacity of 25.5bcm. Gas is also imported via the TotalEnergies-operated Frigg system, which connects the Frigg gas field in the Norwegian North Sea to St. Fergus.

There are three interconnectors. The first runs 235km between compression terminals at Bacton in eastern England and Zeebrugge in Belgium. It is operated by Interconnector UK, which is backed by La Caisse de depot et placement du Quebec (23.5%), CDP Investissements (10.0%), ConocoPhillips (10.0%), Distrigas (11.41%), Fluxys (15.0%), Gazprom (10.0%), E.ON Ruhrgas (15.09%) and Eni (5.0%). Snam and Fluxys reached an agreement to buy E.ON Ruhrgas's 15.09% stake in Interconnector UK for EUR127.0mn on May 16 2012. The pipeline is bi-directional, with a capacity of 25.5bcm from the UK to Belgium (forward flow) and 20bcm from Belgium to the UK (reverse flow).

The second interconnector runs from Balgzand in the Netherlands to Bacton. It is a JV between Gasunie (60.0%), E.ON Ruhrgas (20.0%) and Fluxys (20.0%). The transport of gas to the UK started in December 2006. The third (ie, the UK-Eire interconnector) links Moffat in southwest Scotland to the Republic of Ireland. The licence for this one-way pipeline is held by Bord Gáis Éireann.

Competitive Landscape

Competitive Landscape Summary

- Shell and Equinor are set to face legal challenges from climate activists Greenpeace and Uplift over the development of the Jackdaw and Rosebank oil and gas fields in the UK, with the court hearing scheduled for November 12, 2024. The UK government's decision to drop its legal defense has heightened the stakes, with the outcome potentially influencing future fossil fuel projects in light of recent climate commitments and a landmark UK Supreme Court ruling on emissions from burning fossil fuels.
- In May 2024, the North Sea Transition Authority completed the final tranche of the 33rd licensing round, offering companies another 31 permits. That followed 27 licences offered in October 2023 and 24 in January 2024. Shell, Equinor, BP, TotalEnergies and NEO are among the 17 separate companies that were offered the blocks in the early 2024 second tranche.
- In September 2023, Ithaca Energy finalised the acquisition of Shell's 30.0% ownership share in the Cambo field for an undisclosed fee, giving the company full ownership of the asset. The field is estimated to possess around 800mn bbl of recoverable oil reserves.
- In June 2023, the UK government introduced the Energy Security Investment Mechanism. The mechanism is a new fiscal measure that will set a minimum price under which the 2022 Energy Profits Levy will not be levied in an effort to make the windfall tax more of a progressive measure. If prices were to fall below the threshold outlined in the mechanism simultaneously for oil and gas at USD71.40/bbl for oil and GBP0.54/therm for natural gas, oil and gas companies operating in the UK would not be subject to the 35.0% windfall levy. The specifics of the mechanism stipulate that both oil and gas prices concurrently fall below the historical 20-year average for two consecutive quarters.
- In March 2023, Equinor reached an agreement to acquire Suncor Energy for a fee of USD850.0mn. The deal includes a non-operated 29.9% interest in the Buzzard oil field, which currently is producing at around 60,000 boe/d. It also includes Suncor's 40.0% operated interest in the Rosebank project, thereby increasing Equinor's stake in the project to 80.0%, subject to regulatory approval.
- In March 2023, the UK-based oil and gas company Prax Group announced a deal to acquire Hurricane Energy for a fee of GBP249.0mn. The deal will see Prax Group take over the Lancaster oil and gas field, the sole asset currently owned by Hurricane Energy.
- BP has acquired a 40.0% stake from Harbour Energy in the UK Viking carbon capture storage project for an undisclosed fee. The project aims to capture up to 10mn tonnes of carbon dioxide by 2030. Harbour Energy will retain its remaining 60.0% ownership of the project.
- In a January 2023 update provided by the North Sea Transition Authority (NSTA), it was announced that the UK 33rd offshore licensing round had attracted a total of 115 bids by 76 different companies across 258 blocks and part-blocks. Results were announced in June 2023.
- In February 2023, Enquest revealed that it will halt production drilling at its Kraken field due to the recent rise in the Energy Profits Levy.
- TotalEnergies stated that it will reduce its UK North Sea investments in 2023 by 25.0%, equivalent to around GBP100mn, due to the recent rise in the Energy Profits Levy from 25.0% to 35.0%.
- Harbour Energy, one of the leading oil and gas producers in the UK, abstained from involvement in the latest UK 33rd licensing round due to the government's decision to raise the energy profits levy.
- In January 2023, China National Offshore Oil Corporation paused plans to sell the entirety of its UK North Sea assets due to bids that failed to meet the company's valuation. It is estimated that the assets could be worth up to USD3.0bn, and the company has suggested that the sale could still happen once business conditions improve.

Key Downstream Players

Company	Refining Capacity ('000b/d)	Market Share (%)	Retail Outlets
ExxonMobil	275	23.5	na
Essar Oil	205	17.5	na
Phillips	221	18.9	400
Valero Energy	210	17.9	1,100e
Prax	110	9.4	na
Shell UK	0	0.0	900e
BP UK	0	0.0	1,300e
Petroineos	150	12.8	

e = BMI estimate; na = not applicable/available. Source: Company data, BMI

Company Profile

BP

Latest Updates

- In April 2024, BP has awarded a contract valued between $50 million and $150 million to Subsea Integration Alliance, a collaboration between OneSubsea and Subsea7, for the engineering, procurement, construction, and installation of subsea pipelines and production systems at the Murlach oil and gas field, 240 kilometers east of Aberdeen in the UK North Sea, with first oil expected in 2025 and the field's life estimated at 11 years. Discovered in 1986, the Murlach field is estimated to contain recoverable reserves of approximately 25.9 million barrels of oil and approximately 602 million cubic metres (bcm) of gas. The resource will be extracted from a Triassic Skagerrak reservoir.
- In February 2024, BP adjusted it's Oil & Gas strategy. BP said it planned a 25% cut in oil and gas output by 2030, stepping back from a previous goal of a 40% reduction. This is projected to lead to a total crude production rate of 2 million b/d towards the tail end of the decade. These investments will be geared towards the Middle East and the Gulf of Mexico.
- According to 2024 updates, BP is working on plans for Phase 3 of the Clair Ridge project West of the Shetlands. The project would target Clair South, one of the UK's largest remaining undeveloped offshore accumulations. FID could be reached in 2024 or 2025.
- In late 2023 BP, officially begun oil and gas production at the Seagull field situated in the UK North Sea, in line with our expectations. Output at the field is due to gradually ramp up to a peak production rate of around 40,000b/d. BP owns a 50.0% share in the field, Neptune Energy 35.0% and JAPEX 15.0%.
- Late 2023, the UK government approved the Murlach oil and gas field redevelopment project, headed by BP. The redevelopment will recover around 26mn barrels of oil and 602mn cubic metres of gas. It will consist of two production wells and a subsea tieback to the Eastern Trough Area Projects installations. Peak production would be of 20,000b/d of oil and 0.2bcm of associated gas per year.
- In an update provided in May 2023, BP announced that it had paid around USD1bn in UK windfall taxes since its introduction, with the company paying some USD300mn in UK windfall taxes in Q123.
- BP acquired a 40.0% stake from Harbour Energy in the UK Viking carbon capture storage project for an undisclosed fee. The project aims to capture up to 10mn tonnes of carbon dioxide by 2030. Harbour Energy will retain its remaining 60.0% ownership of the project.

Strengths	Weaknesses
• Strong retail brand and network. • Significant North Sea portfolio. • Petrochemicals/biofuels production capability.	• Greatly reduced upstream presence. • Mature and competitive marketplace.
Opportunities	**Threats**
• New UK licensing rounds, although this could change with the new Labour government. • West of Shetland development projects. • Gas market growth. • Low-carbon energy investments.	• Risk of further windfall taxes being introduced by the new Labour government. • Group shift away from Western European focus. • Competition from Norwegian gas.

Company Overview

The UK remains a core part of BP's portfolio. The company has access to a large amount of existing infrastructure. Utilising this existing infrastructure allows the company to lower capital and operating costs for developing satellites and near-field discoveries. We believe that BP will continue to divest underperforming assets in this mature and relatively high-cost region. The downstream asset base has been greatly reduced, with a network of just over 1,200 service stations and some petrochemicals/biofuels capacity.

Key Assets In The UK

Field Name	Field Type	Production Peak, boe
Quad 204	Oil & gas	213,000
Clair Ridge	Oil	100,000
Culzean	Gas	60,000-90,000

Source: BMI

Key Financial Data, USDmn

	2021	2022	2023
Revenue, Adj	157,739	241,392	210,130
EBITDA, Adj	37,147	60,362	42,964
Capex	10,887	16,330	14,285
Net income	7,565	-2,487	15,239

Source: Bloomberg, BMI

Shell

Latest Updates

- In December 2024, it was announced that Equinor UK Ltd and Shell UK Limited are combining their UK offshore oil and gas assets to create the largest independent oil and gas company in the UK North Sea, jointly owned by Equinor and Shell (50% each), aiming to sustain domestic production and energy security; the new company, based in Aberdeen, will include various equity interests and exploration licenses, and is expected to produce over 140,000 barrels of oil equivalent per day by 2025, with the transaction subject to approvals and expected to complete by the end of 2025.
- In August 2024, The circular FPSO for Shell UK's Penguins field redevelopment in the northern North Sea, based on the Sevan 400 design with a processing capacity of 45,000 bbl/d and a storage capacity of 400,000 bbl, was installed in 165 m water depth last month, with Sevan SSP assisting in the transport and installation; Shell operates the field in partnership with NEO Energy.
- In July 2024, Viaro Energy, via its subsidiary RockRose Energy, acquired a 100% working interest in Shell and ExxonMobil's UK Southern North Sea gas assets, which produced around 28,000 boepd in 2023, representing about 5% of the UK's total gas production; the acquisition includes 11 operated offshore assets, one exploration field, and the Bacton gas receiving terminal, significantly expanding Viaro's portfolio and reinforcing its commitment to the UK North Sea.
- Shell's 35,000b/d Penguins oil project is expected to commence production in H224. The floating production storage and offloading vessel that will be utilised for production from the field is currently undergoing final alterations at a shipyard in Norway.
- In early 2024, Shell took a final investment decision on the long-awaited Victory gas project in the UK's West of Shetland waters. This is 47 years after the field was originally discovered by Texaco. The development will use a single subsea well, which will be tied back to existing infrastructure at the Greater Laggan Area system (TotalEnergies). The field will produce 1.5bcm at peak. Victory's gas will be processed onshore at TotalEnergies' Shetland gas plant.
- In April 2023, Shell announced the restart of production at the Pierce field situated in the UK North Sea. Production had been taken offline since October 2021 in order to allow alterations to the floating production storage and offloading operating at the field, enabling the production of gas in addition to oil. As a result, peak hydrocarbon production from the field is expected to more than double to 30,000 boe/d.
- In April 2023, Shell announced that they were pulling out of North Endurance Partnership's carbon capture storage project based in the Humber region of the UK. The project is targeting the capture and storage of up to 20mn tonnes of carbon dioxide per annum. Shell affirmed that it will be refocusing efforts on the Acord CCS project based in Scotland, in which it is lead technical developer.
- In February 2023, Shell made a significant discovery of roughly 8.5bcm of natural gas at Pensacola licence P2252 situated in the Southern UK North Sea. Shell owns 65.0% working interest in the licence, Deltic Energy 30.0% and ONE-Dyas 5.0%.

Strengths	Weaknesses
• Well-established presence. • Strong balance sheet and cash generation.	• Declining North Sea reserves position. • Mature and competitive market. • No fuel production capacity.
Opportunities	**Threats**
• Further asset sales in the North Sea. • UK gas demand growth. • Integrating BG Group's portfolio.	• Risk of further windfall taxes. • Norwegian gas and low LNG prices. • Stringent EU regulation. • Decommissioning liability. • Transition to low-carbon future risks investment into cash generating oil and gas projects.

Company Overview

The integration of BG Group's assets makes Shell one of the largest operators in the UK. The majority of Shell's oil and gas production comes from the North Sea. The company holds various non-operated interests in the Atlantic Margin area, principally in the west of Shetland area. Shell continues to look to divesting and rationalising its older, lower grade North Sea assets to improve the quality of its portfolio, following its USD52.0bn acquisition of the BG Group. The incorporation of BG's assets present a number of opportunities for growth, especially regarding gas production. Most notably on December 5th of 2024, UK Shell Plc & UK Equinor Ltd combined their upstream assets in a independent joint venture. The upstream assets involved in the formation of the new independent oil and gas company by Equinor UK Ltd and Shell UK Limited include a range of oil and gas fields and exploration licenses in the UK North Sea. Specifically, Equinor will contribute its equity interests in fields such as Mariner, Rosebank, and Buzzard. Meanwhile, Shell will contribute its equity interests in fields including Shearwater, Penguins, Gannet, Nelson, Pierce, Jackdaw, Victory, Clair, and Schiehallion. The combination of these upstream assets is aimed at maximizing the economic recovery of resources in the maturing North Sea basin, enhancing production capabilities, and securing the UK's energy supply.

Key Assets In The UK

Field Name	Field Type	Production, boe
Clair Ridge	Oil	100,000
Everest East expansion	Gas	10,000
Jackdaw	Gas	Awaiting approval

Source: BMI

Key Financial Data, USDmn

	2021	2022	2023
Revenue, Adj	261,504	381,314	316,620
EBITDA, Adj	55,004	84,289	68,538
Capex	19,000	22,600	22,993
Nert income	20,101	42,309	19,360

Source: Bloomberg, BMI

TotalEnergies

Latest Updates

- In October 2024, TotalEnergies CEO Patrick Pouyanné announced that the company will curb UK investments and restructure North Sea operations if the Labour government increases the windfall tax; the planned tax hike and removal of investment allowances could severely impact the energy sector's capital expenditure and production.
- In June 2024, The Prax Group will acquire TotalEnergies' entire interest in the Laggan, Tormore, Glenlivet, Edradour, and Glendronach fields, the Shetland Gas Plant, and nearby exploration licenses, which produce about 7,500 barrels of oil equivalent per day (90% gas); the transaction includes transferring relevant employees and is subject to regulatory approval. TotalEnergies attributes this sale to their strategy to adapt it's portfolio by diverting from mature non-core assets.
- In September 2023, TotalEnergies received UK government approval to proceed with the development of the Alwyn East oilfield project, situated in the UK North Sea.
- Media reports from Bloomberg suggest that TotalEnergies is considering selling its remaining 40.0% ownership in the Greater Laggan Area gas fields, situated in the UK North Sea.
- In a June 2023 update, TotalEnergies announced that though exploration drilling undertaken at the Benriach well, block 205/05c in the West of Shetland, had encountered gas reserves, the volume of the discovery is most anticipated to be sub-commercial.
- In March 2023, TotalEnergies began exploration drilling at the Benriach Well block 206/05c, situated west of the Shetland. The company is targeting proven and probable reserves estimated to be in the region of 18bcm of gas. The drilling campaign is expected to be completed by the end of Q3 2023. TotalEnergies owns a 50.0% stake in the block, with Rockrose and Kistos each owning another 25.0% share.
- TotalEnergies has sold its 20.0% minority stake in the Greater Laggan Area and the Shetland Gas Plant to Kistos Energy, for a transaction price of USD125.0mn and further payments contingent on the price of gas and if a discovery is found on the licence. Pending completion of the transaction, TotalEnergies will hold a 40.0% stake in the Greater Laggan fields.

Strengths	Weaknesses
• Spread of upstream assets. • Well-established market presence. • Maersk acquisition increases total production volumes.	• Declining upstream portfolio. • Mature and competitive market.
Opportunities	**Threats**
• New UK Licensing Rounds, although this could change with new Labour government. • Introduction of low-sulphur legislation.	• Risk of further windfall taxes being imposed by new govenrment. • Stringent EU regulation. • Gas competition from Norway.

Company Overview

TotalEnergies has been present in the UK since 1962 and is one of the country's leading oil and gas operators. TEP UK operates several fields in the Alwyn and the Elgin/Franklin areas, as well as the Shetland gas plant. It owns interests in several non-operated fields. TotalEnergies continues to invest significantly in the UK, developing the West Franklin Phase II project. The UK upstream contributes 107,000boe/d of equity production. TotalEnergies is increasing its stake in the UK wind sector and there is potential for crossover with its upstream activities.

Key Assets In The UK

Name	Type	Peak Production, boe
Laggan Tormore	Gas	90,000
Glenlivet	Oil & gas	21,000
West Franklin Phase 2	Gas	40,000
Culzean	Gas	100,000

Source: BMI

Key Financial Data, USDmn

	FY21	FY22	FY23
Revenue, adj	184,634	263,310	218,945
EBITDA, adj	38,160	71,578	50,030
Net income	16,032	20,526	21,384
Capex	16,590	15,690	17,722

Source: Bloomberg, BMI

Regional Overview

North American And Western Europe Oil & Gas Regional Overview

Key View: *We expect the NAWE sector to see strong but decelerating upstream production growth over the next decade, dictated by trends observed among two largest producers - the US and Canada. On the fuel production front, the region is expected to see stable output however weakening consumption poses downside risks to this view. In his first act, US President Donald Trump has signed a wave of executive orders, with a some targeting the energy industry. We remain bullish on near term production growth in Norway, driven by the startup of Johan Castberg on March 31.*

To highlight the key trends in our North American and Western Europe (NAWE) Oil & Gas forecasts we have compared the regions through the following key indicators:

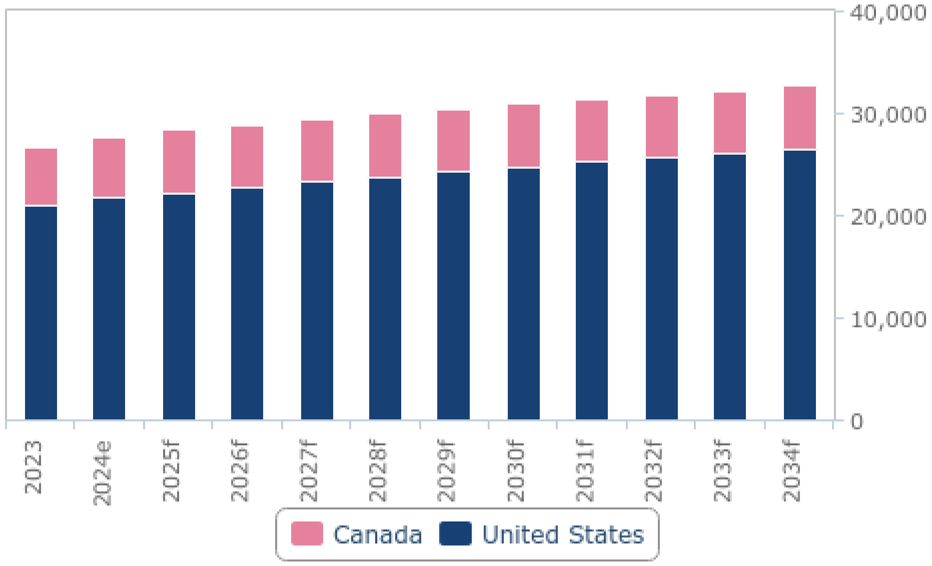
- Oil production
- Gas production
- Refining capacity
- Refined fuel consumption
- Gas consumption

Our NAWE grouping consists of Canada, the US, Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, the Netherlands, Norway, Portugal, Spain, Sweden and the UK.

Oil Production: NAWE Crude Oil Production Growth Strong, But Slowing In 2025

The aggregate crude oil production growth for North America and Western Europe is expected to exceed 31.7mn b/d in 2025, which marks a 2.4% y-o-y growth. The region experiences strong but slowing growth in crude oil production. The regional trends in crude oil production are broadly determined by the US and Canada, which are estimated to deliver respectively 72% and 20% of region's output.

North American Production To Rise Steadily
US & Canada - Crude Oil Production Forecast (2023-2034)



e/f = BMI estimate/forecast. Source: National sources, EIA, BMI

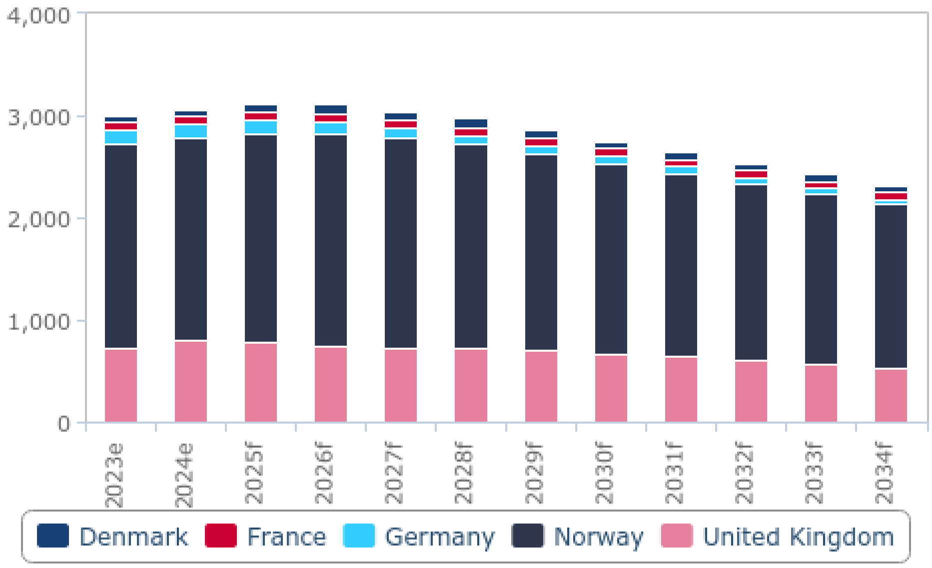
The US has become the largest producer of crude oil in the region and globally over the last two decades, with robust production growth rates fuelled by the shale revolution. In our forecast, the US will see crude oil production expanding at 2.4% y-o-y in 2025, followed by an average of 2.2% y-o-y between 2026-2029. We hold the view of strong but slowing growth in the US crude oil production over the next decade. There are a few reasons behind this view. First, US shale assets are maturing and the companies struggle to see production growth rates from fields returning to historical levels. Second, the key upstream producers have adjusted their strategies over the last years, prioritising shareholder return over production growth. Lastly, we expect largest producers to continue recognising the impacts of broader energy transition, allocating their capex spending on alternative energies and transforming their business into a broader energy companies. That said, we note substantial upside risk to our crude oil production forecast stemming from the Trump administration's policy position towards the industry.

Following his inauguration, President Trump has signed a wave of executive orders, with a couple targeting the energy industry. We highlight the following executive orders: 'Declaring a National Energy Emergency', 'Unleashing American Energy' and 'Unleashing Alaska's Extraordinary Resource Potential' as having the most direct impact on the US domestic upstream oil and gas sector, however other actions, in particular the Executive Order 'Putting America First In International Environmental Agreements', include plans that would also indirectly impact the sector. Some significant downside risks to oil production are also present from the actions of the Trump administration. On April 2 2025, Trump announced a wave of global tariffs starting at 10% on imports into the US, with the highest rate reaching 104% on Mainland China. Due to these trade barriers, our Country Risk team has lowered its expectations for real GDP growth in the US to 0.7% in 2025. This downward revision presents downside risks for oil demand, and thus could way on both oil prices and production.

Canada, as the second largest producer in the region is expected to see strong growth over the near term, with output increasing by 3.1% y-o-y in 2025 after a 4.8% y-o-y growth in 2024. Over the medium term, Canada is set for a much weaker growth averaging at 0.3% y-o-y between 2026-2029. The key rationale behind our somewhat less bullish long-term forecast for Canada is the expected slowdown in investment in heavy oil sands, which dominate Canada's upstream. Canada's upstream sector is now benefitting from some debottlenecking efforts, in particular the start-up of the TransMountain Express pipeline. However, the issue of limited pipeline capacity continues to exist. On top of that, we expect Canada to continue tightening regulatory environment for upstream producers implementing carbon taxes etc. That said, as we see Conservatives likely to regain power in the near future and growing possibility of early elections, we recognise some upside risks to regulatory environment outlook for oil and gas producers in Canada.

UK And Norway To Dominate Upstream

NAWE - Crude Oil Production Forecast For Selected Markets (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

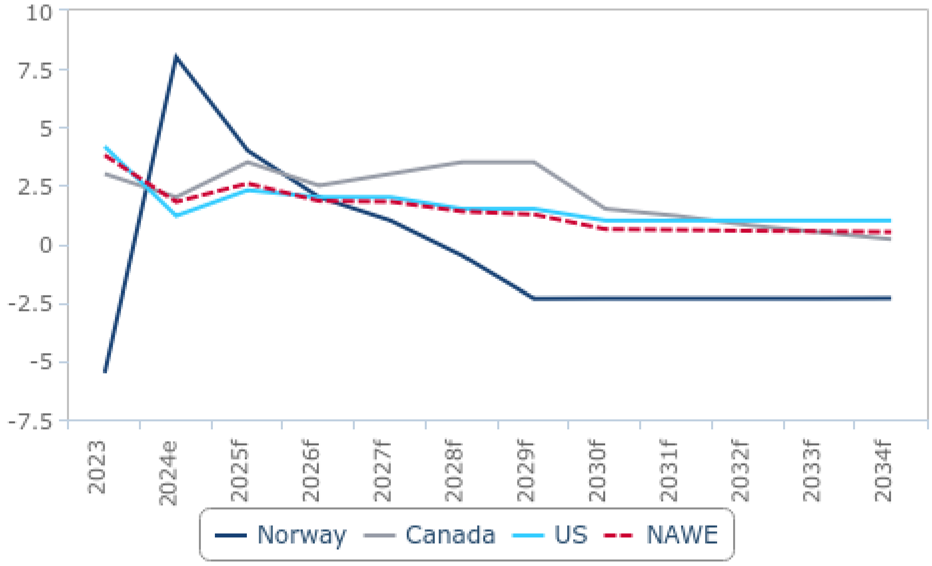
The UK's upstream oil sector is forecasted to decline from 733,800b/d in 2023 to 533,000b/d by 2034, a 27.4% drop, but it will remain a top European producer. The Labour government presents some potential risks that could deter investment, leading to divestment and reduced attractiveness of UK projects. Immediate forecasts remain unchanged, but long-term production is expected to decline due to policy uncertainties. The UK's production peaked in 2019 but has since declined, with a slight increase expected in 2024 before a steady drop to 2034. Norway's oil production, boosted by projects like Johan Sverdrup and Johan Castberg, is expected to peak in 2026 at over 2mn b/d before declining. Despite high oil prices driving new investments, both the UK and Norway are anticipated to experience long-term production declines, reflecting a shift towards alternative energy and resource depletion. This trend is expected to persist through 2034.

Gas Production: Elevated Gas Prices In 2025 To Raise Production Growth In NAWE

We now expect NAWE to see an acceleration in natural gas production growth in 2025, with output expanding by 2.6% y-o-y in 2025, following a muted growth of 1.8% y-o-y in 2024. Similarly to the crude oil market, gas upstream market is dominated by the US, which delivers 77% of regional output, followed by Canada, with 13% market share and Norway with 8%. Regional trends are therefore dictated primarily by the North American markets.

NAWE Gas Output Growth To Accelerate In 2025 Supported By The US And Canada

NAWE - Natural Gas Production Growth Forecast, bcm (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The US is set to increase its natural gas production to over 1,110bcm in 2025 seeing 2.3% y-o-y growth after a muted 1.2% y-o-y growth in 2024. Canada will also see accelerating growth to 3.5% y-o-y, from 2.0% y-o-y in 2024. Overall, we see growing natural gas price benchmarks in this part of the world to boost production. We currently forecast Henry Hub prices averaging at USD3.4mnbtu in 2025, seeing a staggering over-40% increase in price from an average of USD2.4mnbtu in 2024. This price uptick will improve the sentiment on the upstream gas markets in North America. Both markets are set to expand their LNG export capabilities in the short term which will also boost the sentiment and tighten the demand for natural gas and see midstream capacity expansion which will support gas production growth. However, in the long term, natural gas production growth in both markets is set to slow, given lingering debottlenecking issues and weakening demand growth in both countries. That said, the support for the natural gas sector from President Trump and growing potential for the Conservatives to take over the government control in Canada raises upside risks to the domestic consumption, LNG industry and therefore gas production forecasts.

Norway dominates Europe's gas production landscape. Norway's gas production saw growth of 8.0% in 2024, and this bullish trend is set to continue into 2025 with a further 4.0% growth to reach 131.0bcm. This growth is driven by new projects like Equinor's Eirin field and Aker's Yggdrasil project. Despite these gains, long-term production is projected to remain flat, peaking at 135.0bcm in 2027 before declining to 116.7bcm by 2034. High gas prices and geopolitical tensions, particularly after Russia's invasion of Ukraine, have increased European demand, potentially extending investments in Norwegian gas projects. However, Norway's transition away from fossil fuels and limited capacity at mature fields may constrain long-term growth. Projects such as the Troll Phase 3 expansion and Greater Oseberg Area development are expected to support production stability. Norway's output remains closely tied to European demand, which has surged due to geopolitical factors, ensuring a focus on Norwegian gas as Europe seeks to diversify away from Russian imports.

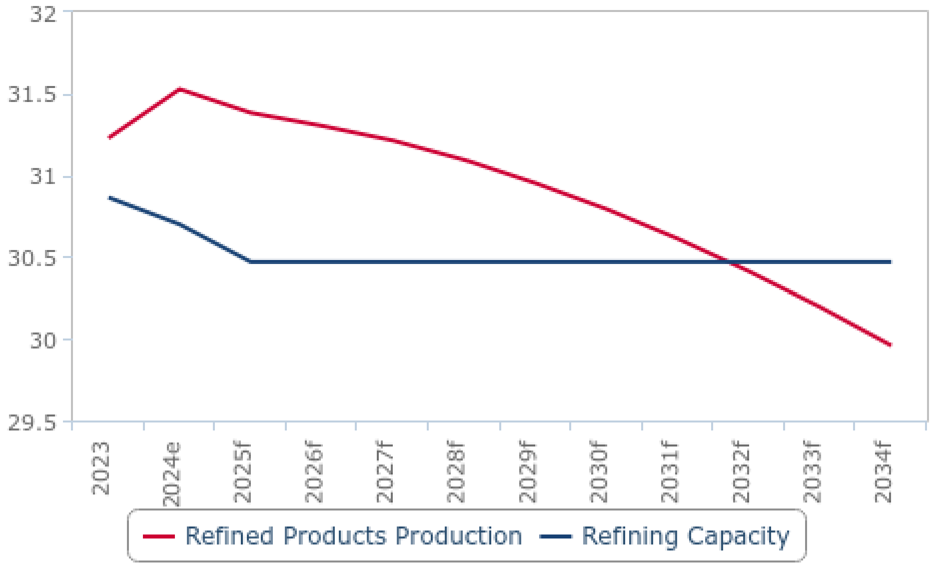
Refining Capacity And Production: Stable Refining Capacity With Declining Production

The NAWE region is home to over 30.0mn b/d of refining capacity with the US encompassing over 18.1mn b/d itself as of 2024. The broad region has some of the most efficient downstream assets and benefits from high utilisation rates. That said, we hold a bearish outlook for the downstream capacity expansion and production for the region, which continues to spearhead energy transition efforts seeing limited growth in fuel demand and pursuing efforts to expand alternative fuel production base. Aggregate refining capacity is set to linger at 30.5mn b/d over the next decade, down from 31.2mn b/d ten years ago. Fuel production forecast for the region is bearish, indicating a decline in aggregate average fuel production from 31.5mn b/d in 2024 to below 30.0mn b/d in 2034. In 2025, the region is expected to see a decline in fuel production of 0.5% which is further supported by bearish outlook on global fuel prices, on the back of weaker oil prices and narrowing margins for refiners, which will disincentivise production growth. We expect 2025 gasoline prices to average at USD215/gal, followed by a USD227/gal average for 2026-2028. We have revised the average global diesel price forecast downward to USD93/bbl for 2025, reflecting ongoing demand-side weaknesses in these major markets. Despite strong air travel demand, significant increases in global refining capacity are outpacing consumption growth, leading to an oversupply and putting downward pressure on jet fuel prices and margins. Forecasts for 2025 jet fuel prices have been lowered to USD93.4/bbl due to oversupply concerns and softening demand growth.

The US is set to see a weakening growth in fuel production in 2025, before a decline in output starting in 2027. This forecast is supported by a weakening outlook on fuel demand given increasing fuel efficiency and ongoing energy transition efforts in the transportation sector. However, this trend is likely to be hampered by scrapping of the policies facilitating electric mobility planned by the President Donald Trump. Canada is also expected to see declines in fuel production starting in 2025 onwards as transport electrification efforts bear fruit. That said, the growing possibility of the return to power of the Conservative government could slow these efforts, adding some upside risks to fossil based fuel production.

Muted outlook On NAWE's Downstream Sector

NAWE - Refining Capacity And Refined Products Production Forecast, mn b/d (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The UK's refining sector is forecasted to see its refining output decrease from 1.10mn b/d in 2024 to 924,100b/d by 2034, driven by weak fuel demand and competitive pressures from more efficient refineries in Asia and the Middle East. The upcoming closure of the Grangemouth refinery in 2025 will reduce refining capacity by over 10%, leaving the UK with just five operating refineries. Meanwhile, Norway's refining sector, anchored by the Mongstad facility, is set to see refined products production fall from 229,000 b/d in 2024 to 191,900 b/d by 2034. This decline comes in the wake of the Slagen refinery's closure in 2021, which resulted in a 33.1% reduction in refining capacity. Despite these challenges, Norway benefits from a direct crude oil feedstock supply from the North Sea, allowing it to maintain operations at approximately 240,000b/d capacity through the forecast period.

Refined Fuel Consumption: Bearish Outlook On Regional Fuel Demand

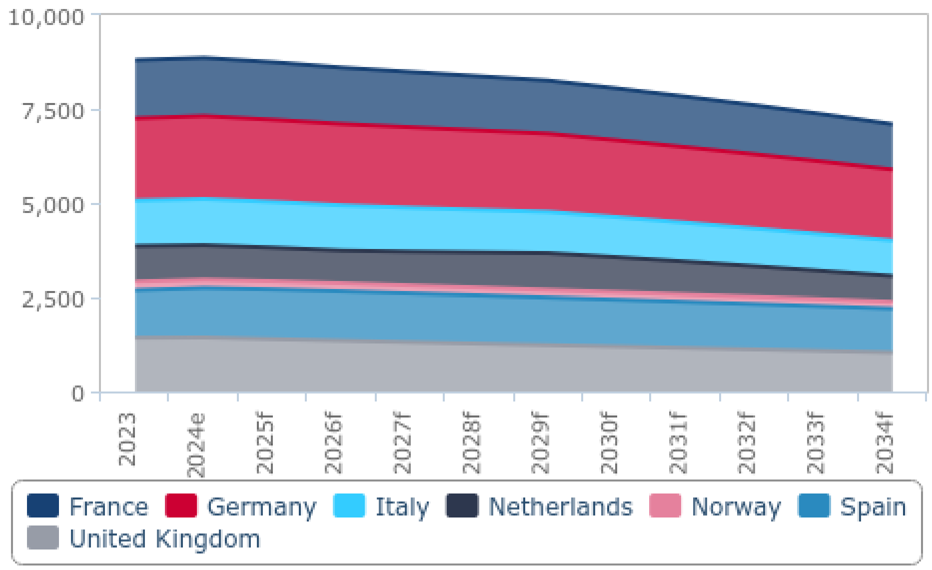
We expect NAWE to see aggregate fuel consumption declining from 34.1mn b/d in 2024 to 31.4mn b/d in 2034. We see similar trends playing out in North American and Western European countries with the progressing energy transition taking a bite into fuel demand.

Total fuel consumption in the US lingers slightly above 20.0mn b/d, which makes up 63% of total regional fuel demand. We hold a bearish outlook for the US fuel consumption, given the anticipated growth in in electric mobility market penetration. Although the victory of President Donald Trump is expected to slow the electric vehicle adoption, we maintain the view of positive growth in passenger electric vehicle sales over the next decade, which will reduce demand for refined products, in particular gasoline and diesel. Similarly, we hold a muted view for Canada, which will see its total fuel demand declining from 2.4mn b/d in 2024 to 1.9mn b/d in 2034.

Western Europe's fuel consumption is set for a long-term decline due to factors like increased EV sales and strict emission standards reducing traditional fuel demand. Efforts in energy efficiency and reduced oil dependency in countries like France, the UK, and Germany are accelerating this trend, with policies supporting cleaner vehicles and renewable energy transitions further diminishing oil use. Despite some resilience in fuels like jet fuel or LPG, overall consumption is projected to drop from 8.8mn b/d in 2024 to 7.2mn b/d by the end of the forecast period, marking a 17.67% decrease.

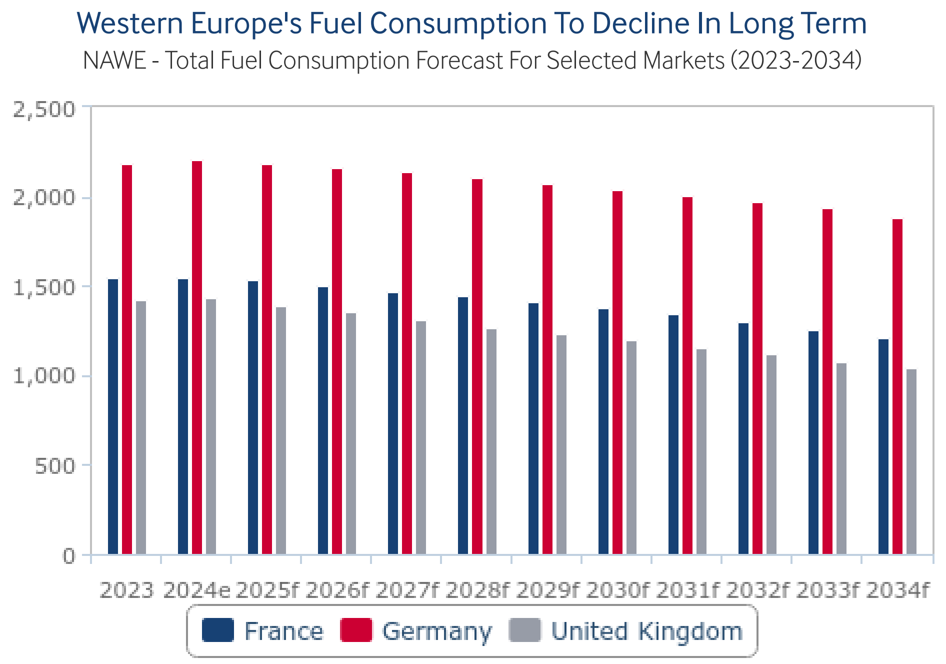
Germany Dominates Fuel Consumption In Western Europe

NAWE - Total Fuel Consumption Forecast For Selected Markets (2023-2034)



e/f = BMI estimate/forecast. Source: EIA, BMI

The chart above shows fuel consumption forecasts for Germany, France, Italy, the Netherlands, Norway, Spain, and the UK from 2023 to 2034, highlighting a downward trend. As of 2025, Germany is the largest consumer at 2,19mn b/d. The UK's consumption is expected to decline by 2.66% annually, France's by 1.47%, Italy's by 2.17%, the Netherlands by 2.80%, Norway's by 1.86%, and Spain's by 0.61%. The chart below illustrates reductions in key markets, with the UK showing the steepest decline, followed by France and Germany.



e/f = BMI estimate/forecast. Source: EIA, BMI

We are optimistic about the UK's fuel reduction due to policies like the Zero Emission Vehicle mandate. The transport sector, crucial in Western Europe, accounts for a large share of oil demand, with transport fuels making up over 70% of the UK's and 60% of France's petroleum demand. However, stringent emission regulations and rising EV use are shifting this landscape. France expects EVs to comprise 14.5% of its fleet by 2034, up from 4.2% in 2024, reducing reliance on conventional fuels and shaping long-term consumption trends. The table below outlines policy attitudes in core European markets toward banning ICEs and boosting EV penetration.

Key Policies Targeting Fuel Consumption In Western Europe

Country	Policy Overview
UK	The UK will ban the sale of new petrol and diesel cars by 2035. By 2030, 80% of vehicles sold must be ZEV.
Germany	Germany supports the EU-wide ban on new ICE vehicle sales by 2035. However, there is an allowance for e-fuel powered cars, meaning ICE vehicles running on carbon neutral fuels could be sold after this date. Germany rejected Italy's call to push forward this date citing industry disruptions.
Sweden	Sweden is taking an ambitious stance. Stockholm is planning on banning ICE's from the city center staring in 2025. By 2030 Sweden hopes to have an emissions free city center.
France	France is determined to uphold the EU's green transport legislation, which bans the sale of combustion engine vehicles from 2035, despite German-led efforts to introduce a loophole for e-fuels. French Economy Minister Bruno Le Maire has emphasised that delaying the legislation would be both an environmental and economic mistake.

Source: BMI

Gas Consumption: NAWE's Gas Consumption To Peak In 2030

The NAWE gas consumption is expected to peak in five years, before declining. This view is primarily driven by our outlook on the power sector demand. We now expect the aggregate natural gas demand to reach 1,460bcm in 2030 before declining to 1,435bcm in 2034. In 2025, the aggregate demand is estimated to linger at 1,428bcm.

The US remains the largest consumer of natural gas in the region, followed by Canada. We expect The US to see some growth in gas demand over the medium term, with consumption reaching over 1,000bcm in 2031. We have become more bullish in our natural gas demand forecast outlook as we now expect a more bullish demand form the power sector under the incoming Trump administration. We also recognise some upside risk to natural gas consumption forecast in Canada, which in our core view is set to lower its consumption from a peak of 145bcm in 2029 to 140.6bcm in 2034. The growing risk of the change in regulatory environment should the Conservatives win the next elections in Canada could likely add some boost to the broad oil and gas industry.

For European markets, gas consumption largely peaked in the late 2010s. As of 2024, European gas consumption stands at 338.7bcm, with expectations to decrease to 336.0bcm in 2025. This represents an annual reduction of 0.71%. Countries such as Germany and the UK, with robust GDP growth, historically showed high gas consumption levels, reflecting their advanced industrial operations and extensive infrastructure demands. For instance, Germany's strong economic recovery post-2020 aligns with significant energy needs for its manufacturing and industrial sectors, although recent trends show a decoupling as they transition towards renewable energy. Similarly, the UK's previously high gas consumption mirrored its economic strength and energy-dependent infrastructure, though recent declines suggest a strategic shift towards more sustainable energy solutions.

Oil & Gas Glossary

Term	Description	Term	Description
AOR	additional oil recovery	IOC	international oil company
APA	awards for predefined areas	IPO	initial public offering
API	American Petroleum Institute	JOC	joint operating company
bbl	barrel	JODI	joint organisations data initiative
bcm	billion cubic metres	JPDA	joint petroleum development area
b/d	barrels per day	LAB	linear alkyl benzene
boe	barrels of oil equivalent	LDPE	low density polypropylene
BTU	British thermal unit	LNG	liquefied natural gas
capex	capital expenditure	LPG	liquefied petroleum gas
CBM	coal bed methane	mcm	million cubic metres
CEE	Central and Eastern Europe	MENA	Middle East and North Africa
CSG	coal seam gas	MoU	memorandum of understanding
DoE	US Department of Energy	mt	metric tonne
DM	developed markets	mtpa	million tons per annum
EBRD	European Bank for Reconstruction & Development	NGL	natural gas liquids
EEZ	exclusive economic zone	NGV	natural gas vehicle(s)
EIA	US Energy Information Administration	NOC	national oil company
EM	emerging markets	opex	operating expenditure
EOR	enhanced oil recovery	PE	polyethylene
E&P	exploration and production	PP	polypropylene
EPSA	exploration and production sharing agreement	PSA	production sharing agreement
EV	electric vehicle(s)	PSC	production sharing contract
FID	final investment decision	R&D	research and development
FDI	foreign direct investment	R/P	reserves/production
FEED	front end engineering and design	RPR	reserves to production ratio
FLNG	floating liquefied natural gas	SGI	strategic gas initiative
FPSO	floating production, storage and offloading	SoI	statement of intent
FSRU	floating storage and regasification unit	SPA	sale and purchase agreement
FTA	free trade agreement	SPR	strategic petroleum reserve
FTZ	free trade zone	SSA	Sub-Saharan Africa
GCC	Gulf Cooperation Council	tcm	trillion cubic metres
G&G	geological and geophysical	t/d	tonnes per day
GS	geological survey	toe	tonnes of oil equivalent
GTL	gas to liquids	tpa	tonnes per annum
GWh	gigawatt hours	TRIPS	Trade-Related Aspects of Intellectual Property Rights
HDPE	high density polyethylene	TWh	terawatt hours

Term	Description	Term	Description
HoA	heads of agreement	USGS	US Geological Survey
IEA	International Energy Agency	WIPO	World Intellectual Property Organization
IGCC	integrated gasification combined cycle	WTI	West Texas Intermediate

Oil & Gas Methodology

Connected Thinking

BMI employs a unique methodology known as 'Connected Thinking'. This means that our analysis captures the inter-relatedness of the global economy, and takes into account all of the relevant political, macroeconomic, financial market and industry factors that underpin a forecast and view. We then integrate them so as to explain how they interact and affect each other. Our Connected Thinking approach provides our customers with unique and valuable insight on all relevant macroeconomic, political and industry risk factors that will impact their operations and revenue-generating potential in the industry/industries within which they operate.

We use a transparent forecasting model as a base for our industry forecasts, but rely heavily on our analysts' expert judgement to ensure our forecasts capture all of the insights we derive using our unique Connected Thinking approach. We believe analyst expertise and judgement are the best ways to provide the most accurate, up-to-date and comprehensive insight to our customers.

Oil & Gas Methodology

For the Oil & Gas industry, we have historical data and 10-year forecasts for 45 core industry variables, including oil & gas production, refined fuels production and consumption, refining capacity, refined fuels production, and trade of oil and natural gas. We also have historical data and 10-year forecasts for 36 energy price indicators.

Our forecasts are a combination of analyst expert judgement and a market's own historical time series.

Our Oil & Gas analysts interact with other analytical teams in BMI, including Country Risk, Commodities, Power, Renewables, Autos and Infrastructure. This ensures that they have a comprehensive understanding of external factors that may impact the oil & gas industry outlook on either a market, regional or global level. In addition, our oil & gas forecasts draw on assessments of political risk, regulatory outlook and outlook for capital expenditure by the industry.

There is a constant rolling cycle of data monitoring, with databases being updated on a quarterly basis. Analysts will use their judgement outside of these cycles to implement forecast changes when necessary.

Industry-Specific Methodology

Our approach to forecasting combines both bottom-up and top-down analyses, drawing data from a wide range of corporate, governmental and multilateral sources. The forecasts also leverage proprietary data and analysis from across our 125 markets and 25 industry verticals.

Upstream Production

Our supply-side forecasts are bottom up, aggregating individual projects (both greenfield and brownfield) up to the market level to derive a total number.

We define oil production as crude oil, NGLs and lease condensates.

We define natural gas as dry natural gas, and exclude NGLs, which is captured under oil production.

The data are mostly sourced from companies active in the market and the relevant regulatory agencies such as the EIA and JODI.

We factor in the production capacity as reported by the given company or agency, but will make informed assumptions as to the project start-up date and commissioning periods.

In general, we include only those projects that are post-FID. However, pre-FID projects that we view to have a high probability of progressing will also be included. The likelihood of a project progressing will be decided on a number of factors, including:

- The economics of a given project
- The prevailing oil or natural gas price
- The political and regulatory environment
- Assumptions as to the capital allocation process of the equity partners

Legacy production (production beginning in any year prior to the forecast period) is forecast out, as per historical trends. However, we make adjustments to the assumed decline rate, based on historical decline rates, forecast investment into enhanced oil recovery or legacy field redevelopment, technological developments and other relevant factors.

Production is expressed in b/d for oil and cubic metres for natural gas.

Refining Capacity

Our refining capacity forecasts are bottom up, aggregating individual projects (both greenfield and brownfield) up to the market level and consider nameplate capacity.

The data are mostly sourced from companies active in the market and the relevant regulatory agencies.

We factor in the crude throughput capacity as reported by the given company or agency, but will make informed assumptions as to the project start-up date and commissioning periods. The capacity forecasts cover crude distillation units (otherwise known as atmospheric distillation units). They do not cover secondary processing capacity.

In general, we include only those projects that are post-FID. However, pre-FID projects that we view to have a high probability of progressing will also be included.

It is expressed in b/d.

Refining Capacity Utilisation

This is a derived indicator. The value is calculated as refined fuels production as a proportion of nameplate refining capacity. Given the lower density of refined fuels, a refinery running at 100% of its nameplate (crude) capacity will operate at above 100%, according to this indicator. Process optimisation and debottlenecking, which will increase the crude throughput at a given facility but will not be reflected in our headline refining capacity forecast, can also lead to over-utilisation. In general, new and more complex facilities will run at higher utilisation rates than legacy facilities.

It is expressed in b/d.

Refined Products Production

Headline refined fuels production is a function of a market's refining capacity and its forecast utilisation rates. We further break down production into gas oil/diesel, gasoline, jet fuel, kerosene, fuel oil, LPG and other products. The breakdown of production is modelled on historical trends.

It is expressed in b/d.

Refined Products And Natural Gas Consumption

Our refined products as well as natural gas consumption forecasts are top-down and leverage a range of market-level forecasts from other analytical teams in BMI, in addition to a market's own historical time series. Common drivers of fuels demand include the domestic economic and political environment, demographic trends and developments in energy-intensive sectors of the economy, as well as infrastructure build out and availability.

As with refined fuels production, we further break down refined products consumption into gas oil/diesel, gasoline, jet fuel, kerosene, fuel oil, LPG and other products.

It is expressed in b/d for oil and billion cubic metres per year for natural gas.

Oil Trade

This is a derived indicator.

We calculate crude and other liquids net exports as crude, NGPL and other liquids production, plus refining capacity gains, less refined products production.

For refined products net exports, the value is calculated as refined products production less refined products consumption. As with our production and consumption forecasts, we further break down trade into gas oil/diesel, gasoline, jet fuel, kerosene, fuel oil, LPG and other products. For total net oil exports (crude, plus, products), the value is calculated as crude, NGPL and other liquids production, plus refining capacity gains, less refined products consumption.

As derived indicators, our net export forecasts do not take account of annual stock change. This can lead to some small discrepancies between our historical data set and observed trade flows.

It is expressed in b/d.

Gas Forecasts

Gas Trade

As derived indicators, our net export forecasts do not take account of annual stock change. This can lead to some small discrepancies between our historical data set and observed trade flows.

Dry Natural Gas Net Exports

This is a derived indicator. It is calculated as dry natural gas production less dry natural gas consumption.

Of which, LNG Net Exports

LNG net exports are derived based on gross LNG exports, less gross LNG imports.

Gross export and import forecasts are bottom up, aggregating individual liquefaction and regasification projects (both greenfield and brownfield) up to the market level. We rely on our LNG Projects Database, which is a comprehensive catalogue of liquefaction, regasification facilities in each market.

Of which Pipeline Net Exports

This is a derived indicator. It is calculated as theoretical natural gas net exports less LNG net exports. Given that stock changes are implicitly captured in the pipeline net export forecast, there may be small discrepancies between our historical data set and observed trade flows.

Upstream Oil & Gas Risk/Reward Index

Our Upstream Oil & Gas Risk/Reward Index (RRI) quantifies and ranks a market's attractiveness within the context of the oil industry, based on the balance between the **risks** and **rewards** of entering and operating in different markets.

We combine industry-specific characteristics with broader economic, political and operational market characteristics. We weight these inputs in terms of their importance to investor decision-making in a given industry. The result is a nuanced and accurate reflection of the realities facing investors in terms of the balance between opportunities and risks, and between sector-specific and broader market traits. This enables users of the index to assess a market's attractiveness in a regional and global context.

The index combines our proprietary forecasts and analyst assessment of the regulatory climate. As regulations and forecasts change, so the index scores change, providing a dynamic and forward-looking result.

The Upstream Oil & Gas Risk/Reward Index comprises **72 markets**.

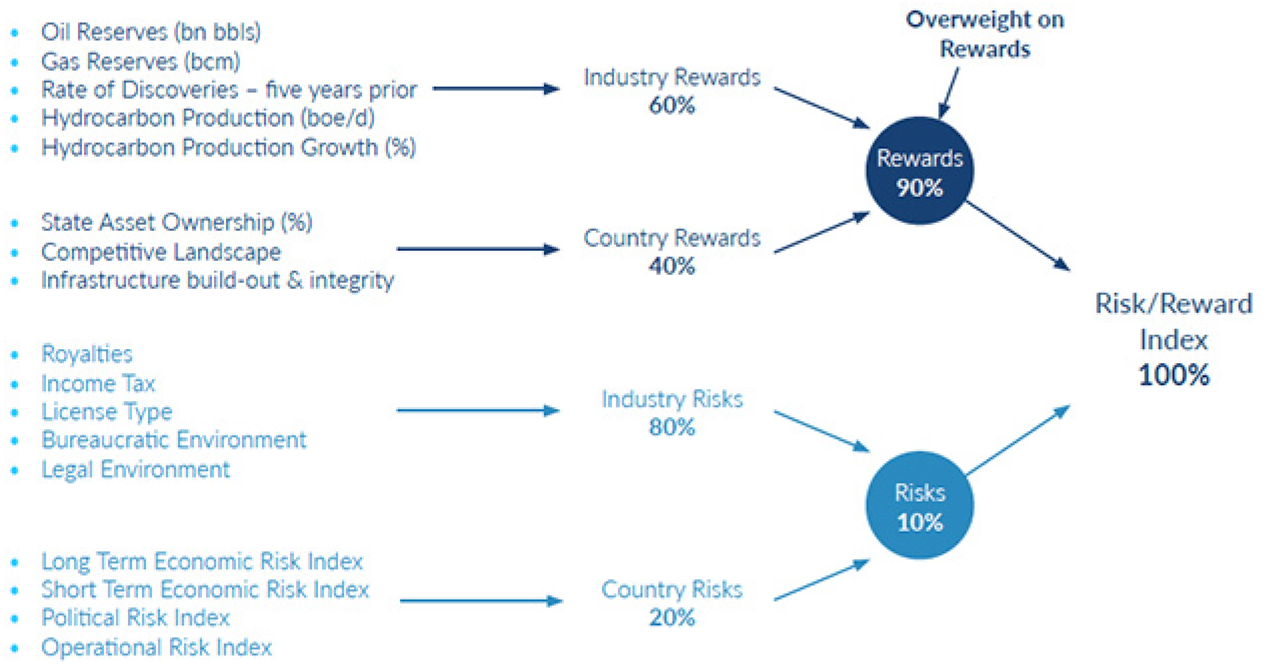
Benefits Of Using Our Upstream Oil & Gas RRIs

- **Global Index:** A global table, ranking all the markets in our universe for upstream oil & gas from most attractive (closest to zero) to most risk (closest to 100).
- **Accessibility:** Easily accessible, top-down view of the global, regional or sub-regional risk/reward profiles.

- **Comparability:** Identical methodology across 72 markets for upstream oil & gas allows users to build lists of markets they wish to compare, beyond the confines of a global or regional grouping.
- **Scoring:** Scores out of 100 with a wide distribution provide nuanced investment comparisons. The higher the score, the less favourable the profile.
- **Quantifiable:** Quantifies the rewards and risks of doing business in the upstream industry in different markets around the world and helps identify flashpoints in the overall business environment.
- **Comprehensive:** Comprehensive set of indicators assessing industry-specific risks and rewards alongside political, economic and operating risks.
- **Entry Point:** A starting point to assess the outlook for the upstream oil & gas industry, from which users can dive into more granular forecasts and analysis to gain a deeper understanding of the market.
- **Balanced:** Multi-indicator structure prevents outliers and extremes from distorting final scores and rankings.
- **Methodology:** It is a combination of proprietary BMI forecasts, analyst insights and globally acceptable benchmark indicators.

Weightings Of Categories And Indicators

Upstream Risk/Reward Index



Source: BMI

The RRI matrix is divided into two distinct categories:

Rewards: Evaluation of an industry's size and growth potential (**Industry Rewards**), and macro industry and/or market characteristics that directly affect the size of business opportunities in a specific industry (**Country Rewards**).

Risks: Evaluation of micro, industry-specific characteristics, crucial for an industry to develop to its potential (**Industry Risks**) and a quantifiable assessment of the political, economic and operational profile (**Country Risks**).

Assessing Our Weightings

Our matrix is deliberately overweight on **Rewards** (90% of the final RRI score for a market) and within that, the **Industry Rewards** segment (60% of final Rewards score). This is to reflect the fact that when it comes to long-term investment potential, industry size and growth potential carry the most weight in indicating opportunities, with other structural factors (demographic, labour statistics and infrastructure quality) weighing in, but to a slightly lesser extent. In addition, our focus and expertise in emerging and frontier markets has dictated this bias towards industry size and growth to ensure we are able to identify opportunities in markets where regulatory frameworks are not as developed and industry sizes not as big as in developed markets, but where we know there is a strong desire to invest.

Upstream RRI Indicators - Explanation And Sources

	Source	Rationale
Rewards		
Industry Rewards		
Oil Reserves (bn bbl)	National sources, BMI data	Indicates size of the opportunity for oil developments. Data is for the current year.
Gas Reserves (bcm)	National sources, BMI data	Indicates size of the opportunity for gas developments. Data is for the current year.
Discoveries Rate - last five years	BMI calculation	Outlines the prospectivity and potential of the upstream.
Hydrocarbon Production (boe)	BMI forecast	Five-year forward looking indication of production volumes.
Hydrocarbon Production Growth (boe, %)	BMI forecast	Five-year forward looking indication of production growth.
Country Rewards		
State asset ownership (%)	BMI calculation	Total share NOCs control. Demonstrates the potential access and restrictions to resources.
Competitive Landscape	BMI calculation	Divides resource base by the approximate number of companies operating to indicate the level of competition.
Infrastructure Integrity	BMI calculation	Calculates the extent and quality of oil and gas infrastructure, indicating ease of access and level of maintenance investment needed.
Risks		
Industry Risks		
Licence Type	BMI calculation	Outlines a market's score based on whether oil and gas licences are offered as concessions, production sharing agreements or service contracts.
Income Tax	Government sources	Outlines the relative tax rate incurred by oil and gas companies.
Royalties & Special Taxes	Government sources	Indicates further required payments (and supplementary taxes) beyond income tax.
Bureaucratic Environment	BMI Operational Risk score	Outlines the ease of business processes, with a particular emphasis on mitigating the risk of delay to project timelines.
Legal Environment Risk	BMI Operational Risk score	A second ease of business indicator, highlighting potential challenges with the transparency and effectiveness of rule of law.
Country Risks		
Long-Term Economic Risk Index	BMI Country Risk Index	The Long-Term Economic Risk Index takes into account the structural characteristics of economic growth, the labour market, price stability, exchange rate stability and the sustainability of the balance of payments, as well as fiscal and external debt outlooks for the coming decade.
Short-Term Economic Risk Index	BMI Country Risk Index	The Short-Term Economic Risk Index seeks to define current vulnerabilities and assess real GDP growth, inflation, unemployment, exchange rate fluctuation, BOP dynamics, as well as fiscal and external debt credentials over

	Source	Rationale
		the coming two years.
Political Risk Index	BMI Country Risk Index	The Political Risk Index is a score made up of the mean average across three distinct pillars: Governance Risk, Society Risk and Security Risk. These are aggregated into an overall assessment of Political Risk.
Operational Risk Index	BMI Operational Risk Index	Our Operational Risk Index focuses on existing conditions relating to four main risk areas: Labour Market, Trade & Investment, Logistics, and Crime & Security.

Source: BMI

Downstream Oil & Gas Risk/Reward Index

Our Downstream Oil & Gas RRI quantifies and ranks a market's attractiveness within the context of the downstream industry, based on the balance between the **risks** and **rewards** of entering and operating in different markets.

We combine industry-specific characteristics with broader economic, political and operational market characteristics. We weight these inputs in terms of their importance to investor decision-making in a given industry. The result is a nuanced and accurate reflection of the realities facing investors in terms of the balance between opportunities and risks and between sector-specific and broader market traits. This enables users of the index to assess a market's attractiveness in a regional and global context.

The index combines our proprietary forecasts and analyst assessment of the regulatory regime. As regulations and forecasts change, so the scores change providing a dynamic and forward-looking result.

The Downstream Oil & Gas Risk/Reward Index comprises **92 markets**.

Benefits Of Using Our Downstream Oil & Gas RRIs

- **Global Index:** A global table, ranking all the markets in our universe for downstream oil & gas from most attractive (closest to zero) to most risk (closest to 100).
- **Accessibility:** Easily accessible, top-down view of the global, regional or sub-regional risk/reward profiles.
- **Comparability:** Identical methodology across 92 markets for oil & gas allows users to build lists of markets they wish to compare, beyond the confines of a global or regional grouping.
- **Scoring:** Scores out of 100 with a wide distribution provide nuanced investment comparisons. The higher the score, the less favourable the profile.
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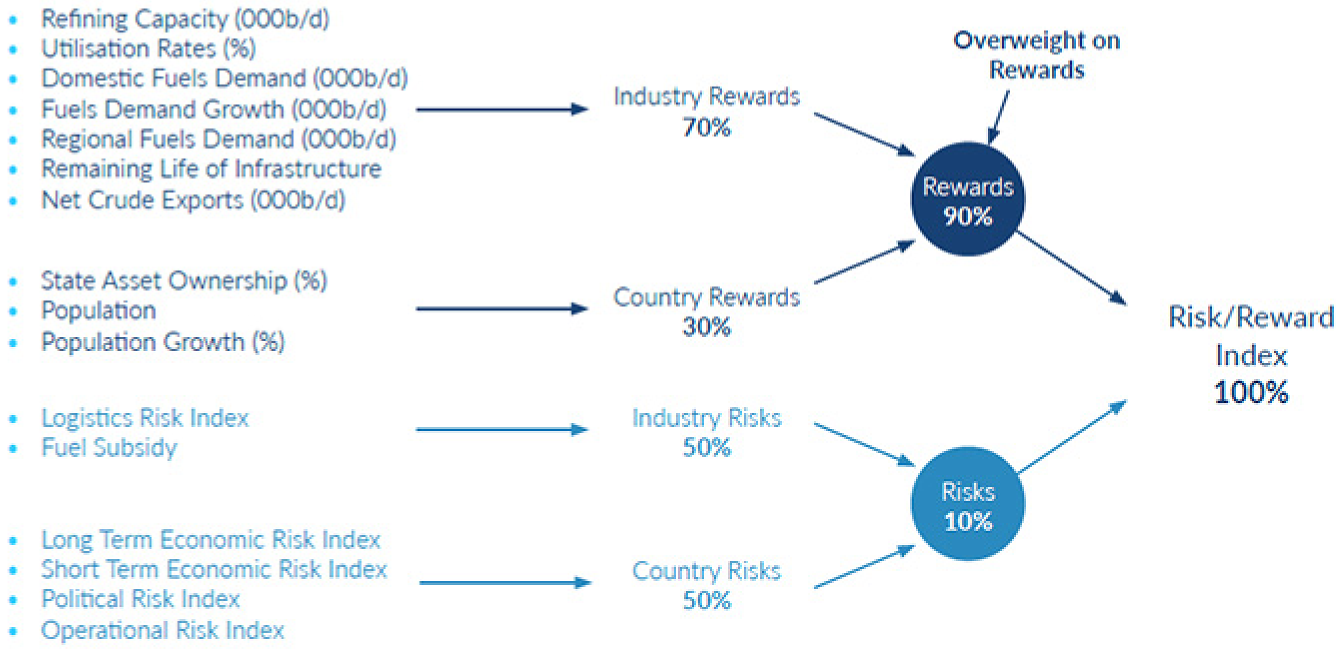
- **Comprehensive:** Comprehensive set of indicators assessing industry-specific risks and rewards alongside political, economic and operating risks.
- **Entry Point:** A starting point to assess the outlook for the downstream oil and gas industry, from which users can dive into more granular forecasts and analysis to gain a deeper understanding of the market.
- **Balanced:** Multi-indicator structure prevents outliers and extremes from distorting final scores and rankings.
- **Methodology:** It is a combination of proprietary BMI forecasts, analyst insights and globally acceptable benchmark indicators.

Weightings Of Categories And Indicators

Downstream Risk/Reward Index



Source: BMI

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Risks: Evaluation of micro, industry-specific characteristics, crucial for an industry to develop to its potential (**Industry Risks**) and a quantifiable assessment of the political, economic and operational profile (**Country Risks**).

Assessing Our Weightings

Our matrix is deliberately overweight on **Rewards** (90% of the final RRI score for a market) and within that, the **Industry Rewards** segment (70% of final Rewards score). This is to reflect the fact that when it comes to long-term investment potential, industry size and growth potential carry the most weight in indicating opportunities, with other structural factors (demographic, labour statistics and infrastructure quality) weighing in, but to a slightly lesser extent. In addition, our focus and expertise in emerging and frontier markets has dictated this bias towards industry size and growth to ensure we are able to identify opportunities in markets where regulatory frameworks are not as developed and industry sizes not as big as in developed markets, but where we know there is a strong desire to invest.

Downstream RRI Indicators - Explanation And Sources

	Source	Rationale
Rewards		
Industry Rewards		
Refining Capacity ('000b/d) - 5-year ave	BMI forecast	Quantifies the current size of the refining sector as a comparison to peer markets.
Utilisation Rates (%) - 5-year ave	BMI calculation	Outlines the efficiency of the existing facilities, identifying over or under capacity.
Domestic Fuels Demand ('000b/d) - 5-year ave	BMI forecast	Shows the size of the domestic market demand as a comparison to peer markets.
Fuel Demand (% growth) - 5-year ave	BMI forecast	Identifies the domestic demand opportunity and trend in consumption patterns.
Regional Fuel Demand - 5-year ave	BMI forecast	Shows the regional export market size to represent the opportunity for exports.
Life Span Of Infrastructure	BMI calculation	Approximate calculation of the life span of infrastructure to identify the remaining operating life.
Theoretical Net Crude Exports ('000b/d) - 5-year ave	BMI calculation	Identifies spare capacity of domestic oil supply as a potential feedstock.
Country Rewards		
State asset ownership (%)	BMI calculation	Indicates how much of the given market is open for private investment.
Population	BMI calculation	Assesses market size based on total population size.
Population Growth (%)	BMI calculation	Assesses potential market size based on the population growth rate over five years.
Risks		
Industry Risks		
Logistics Risk	BMI Operational Risk Index	Offers a comparative indicator on ease of transport for feedstock supply, fuels distribution and import/export flexibility.
Fuel Subsidies	BMI calculation	Penalises a markets' score if fuels prices are sold at below market costs.
Country Risks		
Long-Term Economic Risk Index	BMI Country Risk Index	The Long-Term Economic Risk Index takes into account the structural characteristics of economic growth, the labour market, price stability, exchange rate stability and the sustainability of the balance of payments, as well as fiscal and external debt outlooks for the coming decade.
Short-Term Economic Risk Index	BMI Country Risk Index	The Short-Term Economic Risk Index seeks to define current vulnerabilities and assess real GDP growth, inflation, unemployment, exchange rate fluctuation, balance of payments dynamics, as well as fiscal and external debt credentials over the coming two years.
Political Risk Index	BMI Country Risk Index	The Political Risk Index is a score made up of the mean average across three distinct pillars: Governance Risk, Society Risk and Security Risk. These are aggregated into an overall assessment of Political Risk.
Operational Risk Index	BMI Operational Risk Index	Our Operational Risk Index focuses on existing conditions relating to four main risk areas: Labour Market, Trade & Investment, Logistics, and Crime & Security.

Source: BMI

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