



FUEL, REFINERIES AND THE UK ETS: WHAT POLICYMAKERS NEED TO KNOW

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Abstract

The UK Emissions Trading Scheme was designed to encourage decarbonisation, but after decades of energy efficiency investments by the industry there is little further meaningful decarbonisation that can be economically delivered in the refineries sector.

This means the ETS is now simply a tax, and one that cannot be passed through to consumers who can buy imported refined products that are exempt from carbon taxes. As there are no plans for the sector to be covered by the Carbon Border Adjustment Mechanism, the issue of carbon leakage will not be solved.

This is a material threat to the future of the remaining UK refineries and must be addressed as a policy priority if the sector is to survive.

About Watt-Logic

Watt-Logic is an independent energy consultancy founded by Kathryn Porter in 2016. Originally established as a technical blog analysing electricity and gas markets, Watt-Logic has developed into an internationally recognised consultancy providing independent analysis of energy markets, policy and regulation. The business advises clients across the energy value chain, including generators, suppliers, investors, industrial energy users and financial institutions, on commercial strategy, market design, regulation, investment appraisal and energy trading.

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What are refineries and what do they do?

An oil refinery is an industrial facility that transforms crude oil into usable, everyday products such as petrol (gasoline), diesel, jet fuel, heating oil and the feedstocks for petrochemicals and plastics using complex processes like distillation, cracking, and reforming. Refineries are capital intensive operations whose economics depend on both the price of crude oil and the refined products they produce. Other key economic influences are energy and carbon costs. A more detailed description of refinery operations can be found in Appendix 2.

Understanding the pump price of fuel

The initial interest in refining is often the impact on politically sensitive pump prices for petrol and diesel. Every litre of fuel sold on the forecourt is the end product of a supply chain that spans crude oil extraction, international shipping, refining, distribution and retail, and reflects each of these stages.

The average retail price of ultra low sulphur unleaded petrol in the week commencing 17 August 2026 was 161 pence per litre¹. Of this, fuel duty (a flat excise charge frozen since March 2022) accounted for 52.95 p/l and VAT at 20% added a further 27 pence, applied to the total price including the duty itself, creating the well-known effect of a tax levied on a tax. Together, duty and VAT represent roughly 50% of the pump price.

The pump price of ultra low sulphur diesel in the same period was 181 p/l, of which 52.52 pence was fuel duty and 30 pence was VAT, with the total tax being 45% of the pump price. Tax is therefore about 83 p/l.

The Competition & Markets Authority's ("CMA's") enhanced road fuel monitoring report measures what it calls the "refining spread" as the difference between the crude oil cost and the ex-rack wholesale price set by refineries and importers, which has historically been in the range of 5–15 pence per litre under normal market conditions (ex-rack refers to the wholesale price of a refined product as it exits the refinery)². This is not the typical definition of a refining spread. The true refining margin after all costs is close to zero in mid-cycle conditions and generally positive in strong margin years for example during the market shocks of 2022 and 2026.

"...the UK refining industry faces stiff competition from an increasing number of refiners across the world; overall margins over the five years preceding the market study had been modest and there had been no overall excessive profits for UK refiners,"

- Competition and Markets Authority,
Enhanced road fuel monitoring report:
May 2026

The CMA's measure does not capture the full economics of refining as it excludes refinery operating costs, the cost of delivering crude to the refinery, the premium or discount of the actual crude slate to the Brent benchmark and the crude volume consumed in the refining process itself (typically 2–5% of feedstock volume, this is analogous to the consumption of coal in a blast furnace where the coal is both fuel for the furnace and a feedstock for the chemical reaction). The CMA's refining spread is therefore better understood as a price signal reflecting market conditions for the marginal barrel than as a measure of refinery profitability or the true cost of the re-

fining function in the supply chain.

But refining is not just a question of the pump price of fuel - it is also a security of supply question, because refineries determine what products are available, in what quantities, at what locations, and with what response time when markets are disrupted.

The strategic importance of refining is much greater than its direct contribution to the retail price – domestic refineries determine a country's ability to meet demand from domestic refining rather than imports and this affects security of supply, resilience and exposure to international product markets.

How refineries work

Not all crude oil is the same

Crude oil varies by density and sulphur content:

- Density determines how easily a crude flows and how much it distils into lighter, more valuable fractions. A light crude contains more naphtha and middle distillates than a heavy crude, which is more viscous and yields a larger residue requiring further processing.
- Sulphur content determines refining complexity: sweet crude, with low sulphur levels, requires less desulphurisation and is less corrosive to equipment, while sour crude needs additional processing and greater maintenance to manage corrosive and toxic by-products.

Light sweet crudes are generally easier and cheaper to refine and command a price premium, while heavy sour crudes trade at a discount, but are valuable feedstock for complex refineries equipped to handle them, since their lower purchase price can offset the additional processing cost.

The majority of global reserves are sour crudes, although the main western pricing benchmarks, Brent and WTI are light sweet crudes. Heavy sour crudes include Russian Urals, Saudi Arab Heavy and Venezuelan Merey.

For European refiners who lost access to Russian Urals, a medium sour grade that sat in the sweet spot for diesel-oriented refinery configurations, finding a direct replacement at comparable volume, quality and price has proved difficult.

However, a modern complex refinery (including older refineries that have been upgraded) can process a wide range of crudes. Conversion units such as fluid catalytic crackers and associated hydrotreaters can handle significant variation in feedstock quality, meaning that crude grade is not a hard technical constraint although there is an impact on the economics.

Logistics and commercial optimisation are often more important than crude compatibility. UK refineries (except Humber) generally source crude from internationally traded cargoes entering the English Channel from the west heading towards the Amsterdam–Rotterdam–Antwerp (ARA) region, rather than relying on North Sea oil as it's cheaper and more efficient for shipping.

Refined products slate

¹ <https://www.gov.uk/government/statistics/weekly-road-fuel-prices>

² https://assets.publishing.service.gov.uk/media/69f46615ab602a88957eef99/_Enhanced_road_fuel_monitoring_report_May_2026_v2.pdf

Refineries separate crude oil into usable products

They are complex, capital intensive facilities with decades-long investment horizons

Refineries are complex industrial sites that convert crude oil into usable fuels and feedstocks such as petrol, diesel, jet fuel, LPG, bitumen and petrochemical inputs. Crude oil is a mixture of thousands of different hydrocarbon molecules, ranging from very light gases to heavy, viscous tars.

Refineries separate those molecules, breaking the heavier ones into more useful lighter ones, remove impurities (principally sulphur) and blend the results into finished products that meet precise specifications. The complexity and capital cost of a refinery reflects how far it can go in converting low-value heavy molecules into high-value light ones.

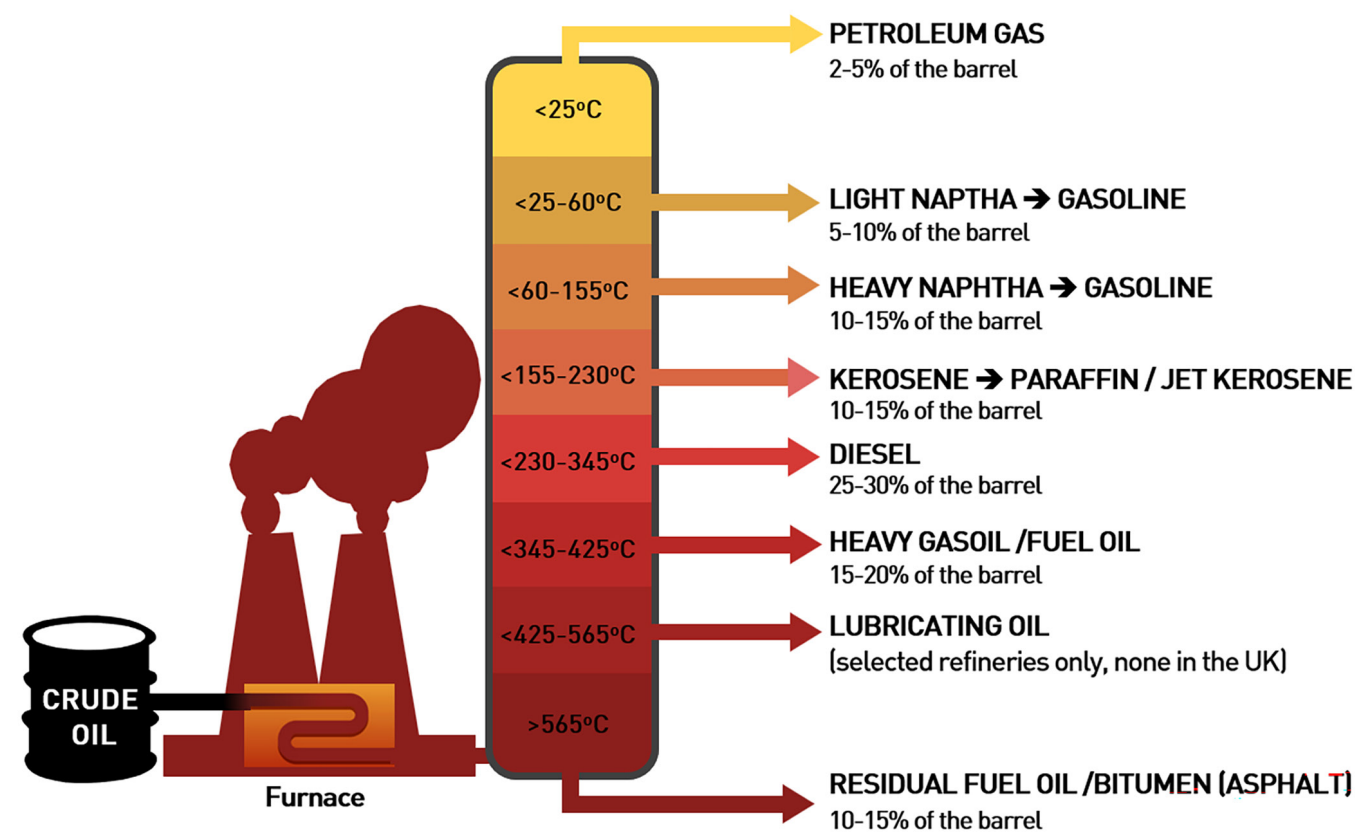
The refining process begins with atmospheric distillation, where crude oil is heated and separated into different fractions according to boiling point. Lighter products such as LPG and naphtha are removed first, followed by gasoline, kerosene, diesel and heavier fuel oils.

The heaviest residual material may then pass into a vacuum distillation unit for further separation under reduced pressure. Distillation does not fundamentally change the hydrocarbons, it simply separates them into streams with different characteristics.

The economic value of a refinery depends largely on its downstream conversion capacity. Simple "hydroskimming" refineries rely mainly on distillation and produce large volumes of lower-value fuel oil. More complex refineries include conversion units such as fluid catalytic converters ("FCCs") and hydrocrackers, which break heavier hydrocarbons into lighter, higher-value products.

FCC units use heat and catalysts to crack heavy gas oils into gasoline and lighter products and have historically been associated with petrol-focused

Fractional distillation of crude oil in refineries



Figures are approximate and do not include refinery fuel consumption and losses (~5-10% of the barrel)

Source: Watt-Logic

refining systems, particularly in the UK and US. Hydrocrackers perform a similar conversion role but use hydrogen under high pressure, producing cleaner products with higher diesel and jet fuel yields. European refineries have increasingly invested in hydrocracking capacity because European demand is structurally stronger for diesel and jet fuel than for gasoline. UK refineries have generally not followed suit.

There are several reasons for this:

- Capital cost and payback: a hydrocracker is significantly more capital-intensive than an FCC – typically US\$ 1-3 billion for a new unit at meaningful scale. The payback period depends on the diesel-gasoline crack spread differential, which has historically been too low in Europe to justify the investment, particularly given the structural demand decline outlook that makes long-payback capital commitments increasingly unattractive.
- Scale: UK refineries are smaller than the major continental European complexes where hydrocracking investment has been concentrated such as Shell Pernis, Total Antwerp and BP Rotterdam. The economics of a hydrocracker improve significantly at scale - a 270,000 bpd refinery like Fawley is large by UK standards but modest by the standards of the ARA hub complexes where hydrocrackers are typically found. The smaller the refinery, the harder it is to justify the fixed capital cost.
- Ownership and investment cycles: UK refineries have changed hands multiple times - Stanlow from Shell to Essar, Pembroke from Chevron to Valero, Humber from Conoco to Phillips 66. Each ownership transition creates a period of investment uncertainty, and major capital decisions such as adding a hydrocracker require a long-term ownership commitment that has at times been absent at UK refineries.
- Timing: By the time the diesel-gasoline spread widened sufficiently in the 2000s to make hydrocracker investment attractive, the outlook for European refining was already deteriorating - demand growth was slowing, margins were becoming more volatile, and the regulatory environment was increasingly uncertain. The window for justifying a 20-30 year payback investment was narrowing just when the economic case was the strongest.

The result is a structural gap where UK refineries optimise for middle distillates within their FCC configuration but cannot shift their product slate as far toward diesel and jet fuel as a hydrocracker-equipped refinery can. This is one of the reasons the UK is a net importer of diesel despite having significant refining capacity.

Refineries also contain numerous treatment and upgrading units designed to meet product quality and environmental requirements. Hydrotreaters remove sulphur and other contaminants, while reformers and isomerisation units improve gasoline quality and octane. These processes are energy intensive and are a major source of refinery emissions.

The standard industry measure of a refinery's technical sophistication is the Nelson Complexity Index ("NCI")³, which measures the complexity and cost of each major type of refinery equipment. The index describes a refinery's secondary conversion capacity that is its ability to upgrade the heavy fractions that emerge from primary distillation, against its crude distillation capacity.

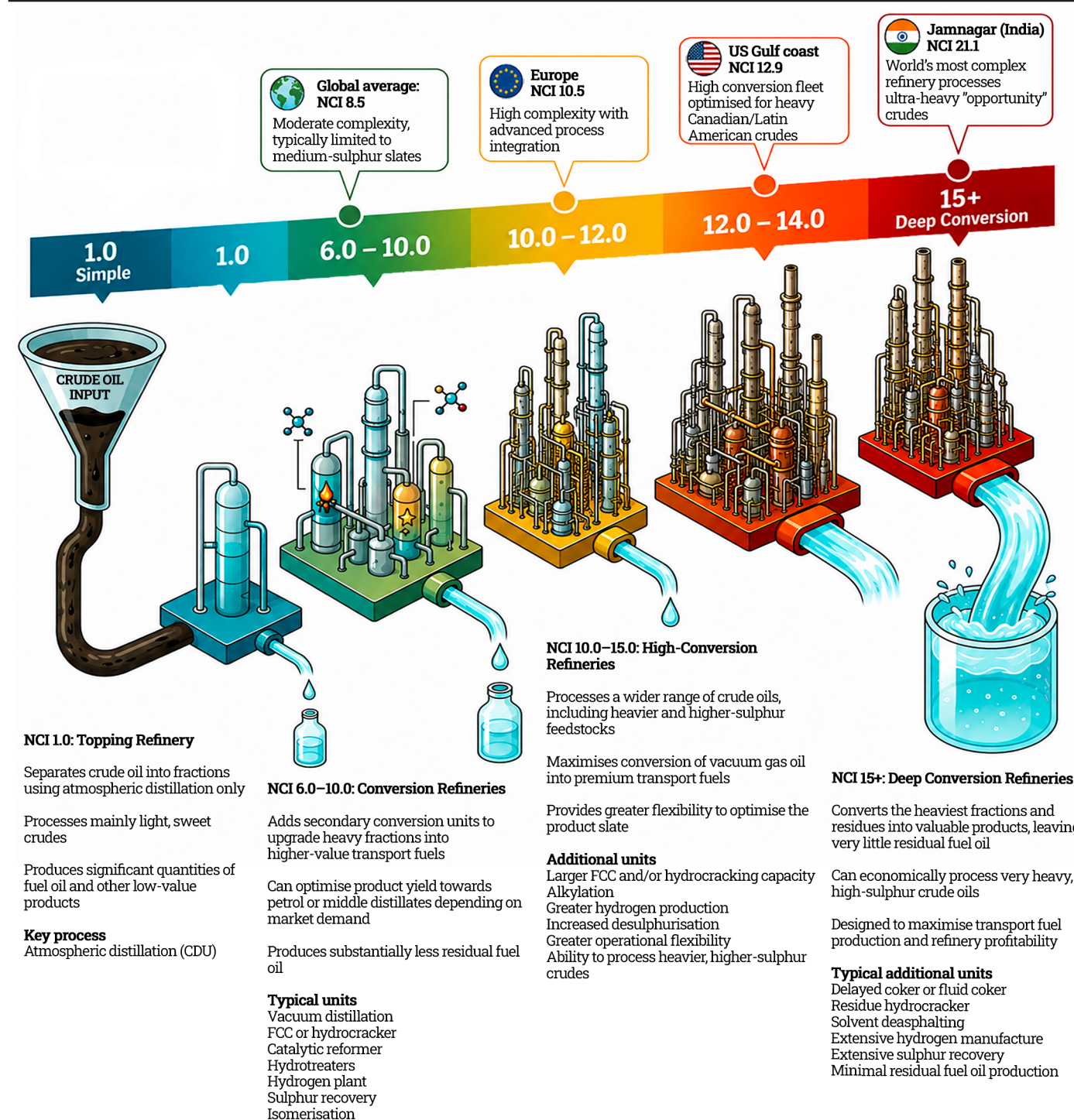
A simple hydroskimming refinery that does little more than distil crude

³ <https://www.eia.gov/todayinenergy/detail.php?id=8330>

oil scores around 2 to 3 on the index while a highly complex coking refinery with hydrocracking, fluid catalytic cracking and multiple treating units can score above 12. A higher NCI generally indicates both higher capital investment and greater ability to extract value from crude feedstock, producing more high-value transport fuels and fewer low-value residual products.

Refining margins are determined by the difference between crude input costs and the value of the products produced, often referred to as the “crack spread”. Because refined products are traded internationally and competition is intense, refinery profitability is highly sensitive to relatively small changes in costs, product demand and regulation. This is particularly important in the context of carbon pricing, where additional operating costs may materially affect competitiveness even when they represent only a small fraction of the final retail fuel price.

Nelson Complexity Index



Source: Watt-Logic

Optimising for middle distillates

The recent disruptions associated with the Iran war have put the structural shortages of middle distillates into sharper focus as roughly 10% of global diesel and 20% of jet fuel trade depends on uninterrupted transit through the Strait of Hormuz⁴. This has led European refineries to maximise kerosene recovery to reduce dependence on imported jet fuel.

Europe is structurally short of jet fuel, relying on imports of approximately 700 kbpd to meet aviation demand. Between May and September 2025, they key summer season, an average of around 400 kbpd of jet kerosene imports originated from the Middle East.

However, Europe's jet fuel market has proved to be more resilient⁵ to the Hormuz disruption than initially feared as rapid supply-side adjustments such as higher US exports, the Nigerian Dangote refinery ramp-up, and elevated European refinery jet yields have offset much of the lost supply. Although the market remains short, and inventories continue to draw down, the deficit has been much less severe than initially feared, and so far a European aviation crisis has been averted.

According to data and analytics firm Kpler⁶, European jet fuel production was around 200 kbpd higher in March this year than last, while refinery yields rose by approximately 2.1% year on year and 1.8% month on month. The increase was observed across the continent, evident in France, Italy, Spain, the UK, Germany and Greece. Kpler had projected European jet fuel production growth of around 160 kbpd year-on-year through yield optimisation, so the actual growth indicated that refiners were able to shift yields more aggressively.

Refineries in the US, Nigeria, Japan and South Korea have adopted a similar approach, but Chinese and Indian jet fuel yields fell during the same period. Overall the global picture is one of higher jet yields, with associated reductions in gasoline balances.

“It is worth noting that Europe is not a single integrated system: airport infrastructure and logistics vary considerably by country, and the UK and France, both carrying deep short positions and a higher dependence on Gulf supplies, are the most exposed and could face further disruption earlier than the aggregate picture suggests,”

- Nikhil Dubey, Kpler

Jet kerosene yields are expected to remain elevated through the summer, but the scope for further optimisation is increasingly limited as most refiners have already captured the easiest gains with jet fuel specifications, hydro processing capacity and refinery configuration constraining further yield shifts. Also, refineries typically begin positioning for winter diesel production from late Q3 which will further reduce the ability to increase jet kerosene production.

⁴ <https://www.kpler.com/blog/hormuz-escalation-puts-middle-distillates-at-the-center-of-supply-risk>

⁵ <https://www.kpler.com/blog/how-europe-rebalanced-its-jet-fuel-supplies-to-keep-planes-in-the-air>

⁶ <https://www.kpler.com/blog/the-barrel-bends-toward-jet>

Key refinery operating challenges

Refineries cannot flex output freely...

... individual units typically cannot operate below c50–60% of nameplate capacity...

...a refinery cannot simply switch from diesel to jet fuel or eliminate unwanted gasoline production

UK refineries are no different from European peers in operational flexibility...

...but the UK is more reliant on imports

Refineries run a continuous process designed to operate around the clock - stopping and starting is expensive, operationally and technically demanding whilst introducing additional safety hazards. Maintaining a steady supply of crude oil is therefore the first operational priority. For UK refineries, crude arrives almost exclusively by sea. They try to match crude deliveries closely to processing rates, making them sensitive to delays or disruptions to shipping routes.

A refinery operates as a series of linked process units, each with its own throughput rate and operating parameters. Refineries can and do vary their throughput in response to market conditions, maintenance requirements, or crude availability, but there are limits. Running significantly below design throughput is uneconomic because many costs are largely fixed, while running above design throughput risks equipment stress and product quality issues. There are also operational issues with running at a reduced rate that typically prevent units dropping below 50-60% of nameplate capacity.

Operational flexibility within a given configuration is real but limited. Refineries operate within relatively narrow bands and cannot switch from producing primarily diesel to primarily jet fuel overnight. Gasoline output cannot be eliminated regardless of market conditions which is why Europe is long the product.

The UK's operational vulnerabilities are not categorically different from those of continental European refiners, but they are more acute in several respects.

Most European countries retain more domestic refining capacity relative to their demand than the UK does following the 2025 closures, giving them a larger margin before product import dependence becomes critical. Several continental refineries, particularly in the ARA hub, have better pipeline connectivity to inland demand centres and more diverse crude supply

France and Germany explicitly support domestic refining capacity...

... the UK has no equivalent strategic resilience framework...

...UK refineries have not been treated as a strategic priority

Once a refinery closes, its infrastructure, specialist skills and supply-chain relationships are typically lost

routes than UK coastal refineries, although the UK does benefit from diverse crude supplies as it is able to access cargoes bound for ARA via the English Channel. Continental governments have also been more proactive – or interventionist, in response to greater union pressure, particularly in countries such as France and Italy.

France maintains a minimum number of active refineries under a national strategic resilience policy, while Germany has co-funded upgrades at its refineries to ensure some domestic processing remains viable. The UK has no equivalent policy framework.

Asian refineries, particularly in China, South Korea and Japan, are generally newer, larger, and more complex than their European counterparts, with better integration between refining and petrochemicals and more modern process control systems. However, Asian markets are also far more exposed to Hormuz disruption, importing more than 60% of their total crude requirements from Middle Eastern sources.

Middle Eastern refineries are export-oriented by design, built to run at high utilisation rates and move large volumes of product to international markets. Unlike facilities serving domestic markets, export-oriented installations cannot easily accumulate inventory during distribution disruptions, forcing immediate throughput reductions when shipping access is constrained. The current conflict has therefore imposed disproportionate operational stress on precisely the refineries that the global market was most relying on to compensate for tighter supply elsewhere.

For UK refineries, the net position is one of mature assets, limited domestic alternatives if they underperform, constrained distribution infrastructure, and a policy environment that has not historically treated their operational continuity as a strategic priority. The Lindsey closure illustrated how financial losses, maintenance costs and financing difficulties can combine to bring a refinery down relatively quickly, and that once a refinery closes, the infrastructure, skills and supply chain relationships it supported are typically lost.



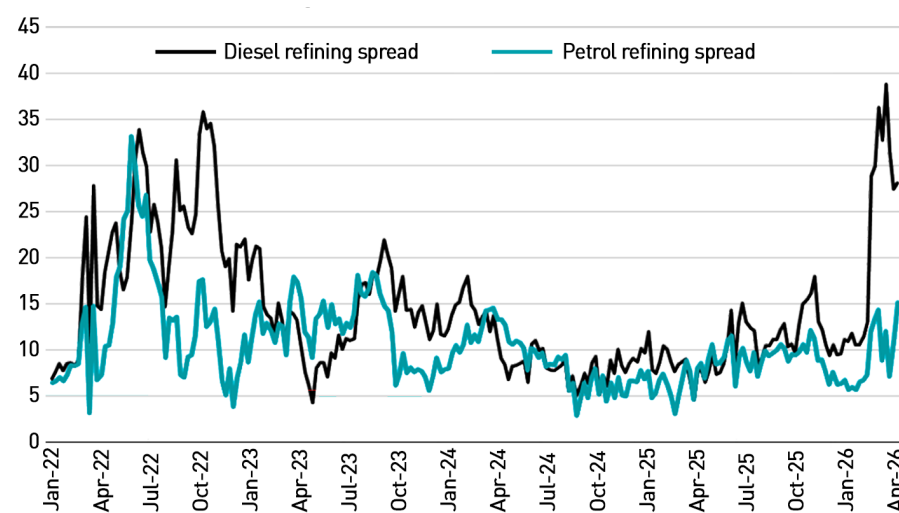
Refinery economics

A refinery's profitability depends on the difference between what it pays for crude and what it receives for the products it sells. This margin, known as the refining margin or crack spread, is not fixed, but varies with movements in crude and product prices, and differs significantly depending on which crude grades a refinery is running and which products it is optimised to produce.

The margin calculation is complex because refineries do not only buy one crude and sell one product, they buy a blend of different crude grades at prices that vary by grade, origin and delivery cost, and sell a slate of products each with its own market price that move independently. The margin at any given moment reflects all of these elements simultaneously.

Diesel cracks and jet fuel cracks reflect the price premium that middle distillates command over crude, while the gasoline crack reflects the value-add of producing petrol. When middle distillate cracks are high and gasoline cracks are low, refineries optimised for diesel and jet fuel earn more than those skewed toward gasoline, and vice versa. The composition of a refinery's product slate therefore has a direct and material effect on its financial performance, independent of its efficiency.

Petrol and diesel refining spreads (pence per litre)



Source: CMA analysis of Department for Energy Security and Net Zero, Platts, Bloomberg and Bank of England data

Refineries are capital-intensive assets with high fixed costs. Energy - gas and electricity to run furnaces, compressors and process units - is typically the largest operating cost after crude oil, followed by staffing, maintenance and catalysts. These costs do not fall proportionally when a refinery reduces throughput. Running at 70% of capacity saves some variable costs but does not eliminate the fixed cost base, which means that margins per barrel have to be significantly negative before a refiner will choose to cut throughput, and highly negative before a full shutdown becomes economically rational.

Turnaround

A refinery turnaround is a scheduled period during which an entire plant, or major part of it, is taken offline for inspection, maintenance, repair, and upgrades. Turnarounds typically take place every three to six years and are planned well in advance, often years ahead, lasting from several weeks to months depending on the scale.

During this period the refinery loses throughput entirely on the affected

units, adding to the cost of the work itself which is significant - a full turnaround at a complex 300,000 to 400,000 bpd refinery can cost from US\$ 150 million to more than US\$ 500 million in direct expenditure⁷, plus the cost of lost throughput, which can equate to over US\$ 3 million per day in lost margin⁸. A full-site turnaround can result in significant direct and indirect costs.

A typical turnaround includes:

- Inspection of equipment to regulatory or company standards;
- Inspection of pipework for corrosion and erosion damage;
- Cleaning, repair and maintenance of equipment, pipework and instrumentation;
- Minor upgrades and modifications; and
- Tie-ins for capital projects.

Turnarounds create an opportunity for plant upgrades that can improve a refinery's throughput, energy efficiency and competitiveness. However, an expensive turnaround project, particularly when combined with deteriorating market or regulatory conditions, may trigger a permanent shutdown, as the expenditure is deemed uneconomic, as was the case with Valero's decision to close its Benicia refinery in California in April 2026⁹. Several other US refineries have faced similar challenges: Phillips 66 closed its Wilmington refinery in California in 2025 after shutting a hurricane-damaged plant in Louisiana in 2021 - the capital costs of repairs being uneconomic. LyondellBasell Industries closed its Lyondell refinery in 2025 when a large capital investment to improve its competitiveness was not deemed to be viable¹⁰.

Regularly scheduled turnarounds are one of the most important and expensive refinery activities. A successful turnaround can add significant value to a refinery in terms of greater efficiency or operational flexibility, while poorly managed turnarounds can create a significant risk of accidents as well as potentially causing major disruption to production after startup, due to leaks and other production trips.

International competitiveness

European refineries occupy a middling position in the global competitive landscape. While North American refineries average an NCI of around 11.6, European refineries tend to average around 8.5-10.5, a little below the Asian average of approximately 9.8¹¹. Modern Asian refineries tend to be more complex with an NCI of around 10-12 or higher. The gap between European and US complexity has widened since the early 2000s, as US refiners invested heavily in upgrading capacity during the shale boom while European refiners, facing flat or declining domestic demand, made relatively few new investments in conversion units.

The practical consequence is that US refineries produce almost all of their output as high-value transport fuels - gasoline, diesel and jet fuel account for approximately 86% of US refinery yields - while producing almost no residual fuel oil (although they are often left with a small amount of low value residual coke). European refineries, while also oriented toward transport fuels, have less conversion depth, produce more residual material, and face the structural problem of a product slate weighted toward gasoline when diesel is the product in tightest supply.

⁷ <https://epcintel.com/insight/europes-refinery-giants-are-becoming-billion-dollar-upgrade-plat-forms-158>

⁸ <https://www.hydrocarbonengineering.com/special-reports/29122025/a-reset-for-europes-refineries/>

⁹ <https://www.opis.com/resources/energy-market-news-from-opis/previously-scheduled-turn-around-to-mark-start-of-benicia-shutdown/>

¹⁰ <https://www.chemicalprocessing.com/asset-management/economics/news/55269191/houstons-old-refinery-to-shut-down-signaling-industry-shift>

¹¹ <https://www.eni.com/assets/documents/eng/scenari-energetici/WORLD-OIL-REVIEW-2020-vol1.pdf>

European refineries occupy a middling position in the global competitive landscape...

...their cost position is materially weaker than their main competitors...

...leading to many refinery closures

UK and European refineries suffer from very high energy prices...

...UK energy prices are four times higher than in the US

The structural cost position of European refineries is materially weaker than that of their principal competitors, for reasons that are largely structural and unlikely to reverse. Bain & Company's analysis of global refinery competitiveness¹² identifies European independents as the most severely challenged, with the highest costs of feedstock, energy and labour, and the highest proportion of capacity falling below the competitiveness threshold. Bain's report is a decade old. The position of European refineries has since deteriorated due to the impact of carbon pricing.

"...since 2009, approximately 30 refineries have shut down continent-wide, leading to a 37% contraction in refining capacity over the past decade. Industry forecasts now indicate that 60% of Europe's total refining capacity is at high risk... Estimates suggest that between 40 and 50 European refineries may cease operations by 2035... representing over 30% of Europe's total capacity,"

- Blooming Trade Data,
A New Era for Oil Refining and Chemicals
as Three Major Forces Emerge

Energy prices for energy-intensive industries in the EU are on average around double those in the US and 50% higher than in China, while in the UK they are around four times higher than in the US^{13,14}. These are not transient cost disadvantages, they reflect structural decisions about energy policy, carbon pricing, labour markets and regulatory costs that are embedded in European industrial policy for the foreseeable future. They are driving deindustrialisation across Europe and adding to the competitive pressures that are forcing refinery closures across the region¹⁵.

¹² <https://media.bain.com/oil-refineries/#>

¹³ <https://www.iea.org/reports/electricity-2026/prices>

¹⁴ <https://www.gov.uk/government/statistical-data-sets/international-industrial-energy-prices>

¹⁵ <https://www.bloomingglobal.com/media/detail/a-new-era-for-oil-refining-and-chemicals-as-three-major-forces-emerge>

Non-commodity costs are a growing component of business electricity bills...

...in 2015 they were just 30–40% of the bill...

...rising to 64% in 2026, driven by policy costs...

...these costs are projected to grow materially by the end of the decade

The growing burden of non-commodity charges within electricity bills, including network costs, policy levies (primarily renewables subsidies and the costs of backup generation or storage) and system-balancing charges, has been driving electricity bills higher. In the UK, energy system operator NESO expects total transmission network charges to increase from £8.9 billion in 2026/27 to £13.6 billion by 2030/31¹⁶. Most of this is recovered from consumers rather than generators, with the "demand residual" rising from £7.52 billion in 2026/27 to £11.75 billion by 2030/31.

Non-commodity costs made up roughly 30–40% of a typical UK business electricity bill in 2015 - by 2026 that share has risen to around 64%, in what is a structural, rather than cyclical, shift¹⁷. Analysts expect this trend to continue as the Government's clean power plans require massive grid expansion whose costs will be recovered from all network users.

The expectation that these high costs will only get higher has led UK refiners invest in onsite generation or enter into private wires arrangements with local generators. However, even where self-generation or private wire arrangements cover the majority of a refinery's demand, the residual exposure to network costs can still be significant, particularly in a low margin environment for refining.

Residual grid imports still attract network charges, and policy cost components. Adding insult to injury is the fact that a portion of these policy costs is made up of government schemes that provide support to energy intensive industries from which refineries are excluded – this means they subsidise support for other energy intensive industries while receiving no such benefit themselves.

European refiners made comparable investments much earlier: ExxonMobil's Antwerp refinery has run a 130 MW cogeneration plant since 2008 that covers more than 100% of the site's own demand (meaning it sells a surplus to the local electricity grid), and Shell's Pernis refinery near Rotterdam has built up similar cogeneration capacity since the 1990s, also selling surplus power to the grid.

¹⁶ <https://www.neso.energy/document/367801/download>

¹⁷ <https://www.moneysupermarket.com/gas-and-electricity/business-energy/a/non-commodity-costs-tuos-duos-charges-explained/>



Cogeneration and private wire supplies narrow the structural cost disadvantage UK refiners face against international peers, but they do not remove it: refiners still pay carbon prices which many international competitors do not, while many of those competitors also benefit from direct government subsidies on top of facing lower energy costs.

European refineries, including those in the UK, have invested heavily in energy efficiency over many decades and are considered world class by industry benchmarks. Energy is the largest single refinery operating cost after crude, and the high energy prices that characterise European markets have driven sustained investment in heat integration, cogeneration and process optimisation that refineries in lower-cost locations have had less commercial incentive to pursue. UK refineries improved their Energy Index (a Solomon Associates metric that measures energy consumption relative to refinery complexity) significantly between the early 1990s and 2010, as documented in government and industry analysis of the period¹⁸.

However, this efficiency advantage does not offset the underlying energy cost differential. Despite their world class energy efficiency, EU refineries face much higher energy costs than their US counterparts. This cost disparity is a key driver of the competitive disadvantage European refiners face relative to the US Gulf Coast and Arabian Gulf¹⁹. The high energy costs that made European refiners more efficient than their global competitors have also made them structurally uncompetitive, and as they have largely exhausted the available efficiency gains, the underlying cost differential continues to widen.

New refinery capacity being added globally is overwhelmingly concentrated in Asia and the Middle East, where national oil companies benefit from captive feedstock at domestic prices, lower energy and labour costs, and government support. Middle Eastern capacity has expanded in the last 20 years from nearly 8 million bpd (“mmbpd”) to around 13 mmbpd, with major additions in Saudi Arabia and the UAE. China has nearly doubled its capacity over the past 20 years, from 10.6 mmbpd in 2005 to 18.8 mmbpd in 2025, while India has grown from 2.9 to 5.2 mmbpd over the same period²⁰.

Refining margins are highly cyclical. The period from 2022 to 2024 was unusually profitable, bearing little resemblance to the long-run economics of refining. Increases in crude oil prices following the removal of Russian supplies were exceeded by increases in product prices. European diesel margins in particular reached extraordinary levels, above \$60 /bbl in mid-2022²¹.

The current crisis has produced a second, more acute margin spike due to the impact of the Iran war. More than 40 Middle Eastern energy assets have been damaged by drone and missile strikes since late February 2026, and additional capacity has been lost as its route to market through the Strait of Hormuz has closed. The IEA estimates cumulative Middle Eastern supply losses have exceeded 1.3 billion barrels²², while European diesel cracks have risen to \$70 /bbl²³.

European refining margins have generally been weaker than the US since the mid-2000s. Before the North American shale boom, US and European margins were broadly similar, but from around 2005 onward, the combi-

Refining margins are highly cyclical, and generally weaker in Europe than the US

UK and European refineries experience a structural cost disadvantage in delivered crude costs

New refineries in the Middle East and Asia benefit from state support and subsidies not available in the UK and Europe

nation of cheap US natural gas, captive light oil supply, high conversion capacity and growing export markets allowed US refiners to pull consistently ahead of European counterparts. European refineries are less able to optimise their product slate in response to market signals than their US and Asian competitors, due to both their configuration and scale.

In the early 2000s, European refineries benefited from proximity to North Sea production and cheap Russian Urals flowing west. Crude oil arrived at or below benchmark prices, effectively a “freight minus” advantage. At the same time, US Gulf Coast refineries were short of crude and paid freight premia to import oil from the Middle East and West Africa.

The shale revolution, coinciding with the decline in North Sea output completely reversed this position. The US Gulf Coast became long crude with domestically produced light tight oil available at prices structurally discounted to Brent, eliminating freight costs on the marginal barrel. European refineries simultaneously lost both advantages: declining North Sea production reduced the availability of cheap local crude, and the loss of Russian Urals after 2022 sanctions forced European refiners to source replacement crude from more further away, incurring higher freight costs. **Europe moved from “freight minus” to “freight plus” at the same time that US Gulf Coast refineries moved in the opposite direction - a structural shift in delivered crude cost that amplified the margin divergence created by the conversion capacity and energy cost differentials.**

The absence of meaningful hydrocracking capacity at all UK and many European refineries (with the exception of some ARA refineries) limits the degree to which operators can shift production towards diesel and jet kerosene when middle distillate margins are strong. US refiners can shift both their crude slate and product mix significantly, having built both feedstock optionality and product flexibility into their conversion units over decades of investment.

New refinery investments in Africa, the Middle East and Asia are adding to the competitive challenges of UK and European refineries. These new refineries often benefit from state support that is unavailable to privately owned European operators. Nigeria’s Dangote refinery, the world’s largest single-train refinery at 650,000 bpd was commissioned in 2024 at a total cost of approximately US\$ 20 billion and operates under a government-mandated Naira-for-Crude programme under which Nigeria’s state oil company NNPC supplies domestic crude in local currency rather than dollars, eliminating the foreign exchange exposure that any other refinery buying internationally-priced crude priced in US\$ would face. NNPC also holds a 7.25% equity stake in the refinery, originally agreed in exchange for guaranteed crude supply²⁴.

Reliance Industries’ Jamnagar complex in Gujarat, which is the world’s largest refining hub with around 1.24 mmbpd of combined capacity was developed within a Special Economic Zone that provides significant tax advantages, and has benefited from preferential access to crude and feedstocks²⁵.

Arabian Gulf refineries operated by national oil companies benefit from similar captive crude supply at domestic prices that are substantially below international benchmarks, reducing feedstock costs in ways that are unavailable to refineries buying crude on international markets. These advantages reflect deliberate industrial policy decisions by governments that regard refining capacity as a strategic national asset and support it accordingly. In contrast, UK and European refineries, competing in the same global product markets, receive no equivalent support while bearing carbon costs and regulatory burdens that their competitors do not face.

¹⁸ https://assets.publishing.service.gov.uk/media/5a80c3a0ed915d74e62304fe/Oil_Refining_Report.pdf

¹⁹ https://www.wpcenergy.org/images/documents/events/youth_forums/tomorrows_leaders/1_European_refining_competitiveness_-_ExxonMobil_2015_WPC_Budapest.pdf

²⁰ <https://www.rystadenergy.com/news/fewer-refineries-greater-capacity-mid-east-asia-lead-charge>

²¹ <https://www.woodmac.com/news/opinion/refinings-perfect-storm-passes/>

²² <https://www.iea.org/commentaries/how-global-oil-supplies-have-readjusted-to-help-fill-the-huge-gap-left-by-the-strait-of-hormuz-shock>

²³ <https://www.argusmedia.com/en/news-and-insights/latest-market-news/2850248-european-refinery-economics-shift-back-to-road-fuels>

²⁴ <https://africaoilgasreport.com/2026/05/refining-gap/inside-the-dangote-refinery-what-the-public-should-know-before-the-ipo/>

²⁵ <https://www.millenniumpost.in/business/no-windfall-tax-on-diesel-atf-exports-from-reliance-sez-refinery-official-654472>

Refineries in the UK and Europe face declining domestic demand...

The outlook for European refineries is challenging. They face a combination of declining domestic demand, rising regulatory and carbon costs, intensifying competition from larger and lower-cost producers elsewhere, and an age profile that makes major capital investment difficult to justify on commercial returns.

...rising regulatory and carbon costs...

While global demand for refined products is not falling – it is moving from the west to the east and south - it is difficult for European refineries to compete with refineries outside Europe for these volumes, given their adverse cost position and lack of access to comparable state support.

...intensifying competition from larger, lower-cost producers elsewhere...

The Prax/Lindsey closure in 2025 illustrated how these pressures can interact: a refinery with acceptable unit economics under favourable market conditions becomes unviable when financing costs, deferred maintenance and a margin downturn coincide. Wood Mackenzie has identified over 1.2 mmbpd of European refinery capacity that is at risk of closure over the next decade²⁶.

...making major capital investment difficult to justify

For UK refineries specifically, the competitive position within Europe is not materially different, but the buffer is thinner. With four refineries remaining, there is less redundancy in the domestic system. The absence of a hydrocracker in any UK refinery since Grangemouth closed means the fleet has less product flexibility than comparable European competitors. The UK's island geography means that it is easy for importers to gain access to the UK market. The limited logistical access to inland European refiners (ie along the Rhine) offers greater protection, up to the point where local inland demand falls away.

Demand for refined products is falling in Europe, driven by deindustrialisation

Outlook for European refined product demand is unambiguously negative...

The mainstream forecast for European refined product demand is unambiguously negative, although market shocks following the Russian invasion of Ukraine and the Iran war have provided periods of relief.

Western Europe's gasoil demand peaked in 2017, and S&P Global Commodity Insights projects that both diesel and gasoline demand will progressively decline through the rest of the decade, driven by electric vehicle adoption and tightening emissions standards²⁷. Wood Mackenzie attributes the demand reduction primarily to climate policy, renewables growth and the

²⁶ https://go.woodmac.com/1/131501/2025-03-31/343k8s/131501/1743433007oJZ9QEM3/global_2035_refinery_closure_threat_2025_update.pdf

²⁷ <https://www.spglobal.com/energy/en/news-research/latest-news/crude-oil/071824-europes-refining-sector-braces-for-major-downsizing-as-margins-stall>

Refineries are exposed to the same pressures as other European industries...

...wider deindustrialisation is destroying demand for refined products in ways that have nothing to do with climate policies

EU industrial energy consumption fell 8.1% between 2014 and 2024 and has been in structural decline since 1990

electrification of transport. This framing ignores another factor that is, in the short to medium term, at least as significant: deindustrialisation.

EU industrial energy consumption fell 8.1% between 2014 and 2024 and has been in structural decline since 1990²⁸. This trend incorporates efficiency improvements and a shift towards less energy-intensive sectors, but the period since 2022 has seen a sharp and rapid contraction in energy-intensive industrial output driven by high energy costs. **This has destroyed demand for refined products in ways that have nothing to do with EVs or climate policy.**

The Cefic European Chemical Industry Closures and Investment Radar²⁹ recorded 37 million tonnes (mt) of European chemical production capacity having closed or announced plans to close between 2022 and 2025, representing 9% of Europe's entire chemical base. This is six times the historical closure rate. Energy costs were cited as the primary driver in 49% of closure announcements, ahead of weak demand at 19% and overcapacity at 9%.

Closures have occurred across Europe, with the largest shares in key chemical producing countries such as Germany (8.8 mt, 25%), the Netherlands (7.2 mt, 20%), the UK (4.5 mt, 12%), France (3.9 mt, 10%), Italy (2.5 mt, 7%), Belgium (2.3 mt, 6%), Spain (1.6 mt, 4%) and the rest of Europe (6.0 mt, 16%). In Germany, BASF has closed ammonia, caprolactam, adipic acid, fertiliser and TDI production lines at its Ludwigshafen complex in successive waves from 2023 to 2025, while committing €10 billion to a new complex at Zhanjiang, China³⁰. Yara closed 400,000 tonnes per year of ammonia capacity at Tertre in Belgium and suspended ammonia and urea production at Ferrara in Italy³¹. It also mothballed a 300,000 tonne ammonia plant in Hull³².

ExxonMobil shut its 800,000 tonne Fife Ethylene Plant in Mossmorran, Scotland in 2026³³ and around 1 mt of ethylene capacity in France while Sabic halted a steam cracker in the Netherlands³⁴. OCI cut ammonia production in the Netherlands, and CF Industries permanently shut its UK fertiliser plant. TotalEnergies intends to close its oldest steam cracker at

²⁸ <https://ec.europa.eu/eurostat/web/products-eurostat-news/w/ddn-20260529-1>

²⁹ <https://cefic.org/resources/european-chemical-closures-investments-radar-2022-2025/>

³⁰ <https://www.echemi.com/cms/1939901.html>

³¹ <https://themerchantsnews.substack.com/p/who-survives-europes-energy-crisis>

³² <https://holderness-gazette.co.uk/ammonia-plant-based-at-chemicals-park-begins-gradual-shutdown/>

³³ <https://eciu.net/media/press-releases/exxonmobil-closes-mossmorran-plastics-plant-in-scotland-comment>

³⁴ <https://ceinterim.com/europe-factory-shutdown-trends/>

Industry is a major consumer of oil products...

...therefore deindustrialisation drives lower demand for refined products

Despite various support schemes for energy intensive industries, UK and European industry struggles to compete with US and Asian peers

High energy costs are exacerbated by the addition of carbon costs

Antwerp by 2027³⁵. In 2026-27 Dow Chemical plans to close an ethylene cracker at Böhlen and chlor-alkali and vinyl assets at Schkopau, both in Germany, and a siloxanes plant at Barry in Wales³⁶.

Industrial closures go beyond the refining and chemicals sectors with energy costs forcing the suspension of closure of production at a range of other sites including the Nyrstar zinc smelter at Budel in the Netherlands and the Speira aluminium plant at Rheinwerk in Germany. Finnish steel producer Outokumpu has closed two German sites, while ThyssenKrupp plans to close its Kreuztal-Eichen site in Germany³⁷.

These closures have a significant effect on demand for refined products as they are also major consumers of diesel for on-site logistics, mobile plant and backup power. They are also significant consumers of fuel oil for process heating. Their closure removes both that direct consumption and the associated road freight demand from supply chains serving those facilities.

The closure of these and other European industrial sites is not cyclical repositioning. Capacity lost in Europe is being replaced by capacity elsewhere, often by other companies although BASF is a notable exception. Global supply in these industries is not contracting in line with European closures, as new capacity is added in the US, the Middle East and China. These are strategic decisions made on 40 to 50-year asset lifecycles, which are highly unlikely to be reversed by future reductions in European energy prices even if they materialise. Once a large industrial plant closes and the workforce disperses, the institutional knowledge, customer relationships and supply chain integrations that underpinned it are lost, and not easily regained.

Energy price support schemes underline industrial competitiveness concerns

European industrial electricity prices are structurally higher than those of its main competitors. In 2025, EU industrial electricity prices were on average double prices in the US and more than 50% higher than in China and India³⁸. In the UK the position is worse: government data show that **UK industrial electricity prices in 2024 were 94% higher than the median of IEA countries**³⁹.

These are not temporary dislocations attributable to the 2022 energy crisis or Iran war, nor are they driven by gas prices - wholesale gas prices across Europe have fallen substantially since their 2022 peak but electricity prices have not followed suit because a significant share of the electricity bill is composed of policy-related costs that are independent of gas market conditions.

In Germany, energy-intensive companies paid an average of €0.1004 /kWh in September 2025, a 57% increase over five years, despite the removal of the EEG renewable surcharge in 2022⁴⁰. The persistence of high prices, rising network charges, capacity payments, the ETS indirect pass-through, and the offshore wind connection surcharge as renewable deployment has accelerated, offsetting the removal of the EEG levy.

³⁵ <https://www.polimericanews.com/articolo.asp?id=284>

³⁶ <https://investors.dow.com/en/news/news-details/2025/Dow-will-shut-down-three-upstream-European-assets-in-response-to-structural-challenges-in-the-region/default.aspx>

³⁷ <https://www.adlittle.com/en/insights/viewpoints/deindustrialization-threat>

³⁸ <https://www.iea.org/reports/electricity-2026/prices>

³⁹ https://assets.publishing.service.gov.uk/media/68da5c14ef1c2f72bc1e4b53/table_531.xlsx

⁴⁰ <https://www.gleisslutz.com/en/know-how/germany-cuts-costs-electricity-intensive-companies-1-january-2026-new-industrial-electricity-price>

The German government's response was to introduce a subsidised industrial electricity price (Industriestrompreis⁴¹) of approximately €0.05 /kWh for the most energy-intensive sectors from January 2026. This was approved by the European Commission under the new Clean Industrial Deal State Aid Framework⁴² and is limited to 50% of a company's consumption, runs until 2028, and has been criticised by industry as falling short of what is needed.

The position is worse in the Netherlands where a 2025 study commissioned by the Ministry of Climate and Green Growth found that large Dutch industrial consumers face a clear competitive disadvantage compared to peers in Germany and France, where more generous levy exemptions and compensation schemes significantly reduce costs. The Netherlands abolished its ETS indirect cost compensation scheme for energy-intensive industry in 2023.

An equivalent scheme in Germany was worth €3 billion in 2023⁴³, leaving Dutch counterparts at a significant disadvantage. Dutch industrial electricity prices were €0.134 /kWh in December 2025⁴⁴ compared with €0.1025 /kWh in Germany after exemptions⁴⁵. Despite this, many **European energy intensive industries struggle to compete with peers in the US and Asia.**

The European Commission adopted the Clean Industrial Deal State Aid Framework ("CISAF")⁴⁶ in June 2025 which adopts a carve-out from state aid rules for electricity price subsidies for energy intensive industries until 2030. CISAF allows member states to subsidise up to 25% of wholesale electricity costs for energy intensive industries on the grounds of preventing carbon leakage.

The UK Government does provide some support for energy intensive industries. In October 2025 it raised the network charge exemption for these businesses from 60% to 90%⁴⁷, saving them an estimated £420 million per year. The planned British Industrial Competitiveness Scheme ("BICS")⁴⁸ from 2027, will exempt qualifying firms from net zero policy costs and represents a significant admission that policy costs have placed domestic industry at a major competitive disadvantage. It is worth noting, however, that refineries are not included in the BICS or similar schemes such as the "supercharger"⁴⁹.

The UK and EU ETS add a further cost element in addition to national policy choices. Under the schemes electricity generators pass the cost of carbon allowances through to consumers via wholesale electricity prices regardless of whether they physically emit carbon - a gas-fired plant setting the marginal price embeds the full ETS cost in the price paid by all consumers, including those buying renewable electricity.

With EU carbon allowances trading at approximately €80 per tonne at the end of June 2026, the ETS cost is a material addition to industrial electricity bills. In 2024, EU member states paid €3.2 billion in state aid compensation to energy-intensive industries to offset indirect ETS costs, representing 13%

⁴¹ <https://www.industriestrompreis.de/>

⁴² <https://fps-law.de/en/fps-blog/green-light-germanys-industrial-electricity-price>

⁴³ <https://www.bruegel.org/policy-brief/europes-under-radar-industrial-policy-intervention-electricity-pricing>

⁴⁴ <https://www.intratec.us/solutions/energy-prices-markets/commodity/electricity-price-netherlands>

⁴⁵ <https://www.smar.de/en/energy-data-compact/energy-data-compact>

⁴⁶ https://competition-policy.ec.europa.eu/about/contribution-clean-just-and-competitive-transition/clean-industrial-deal-state-aid-framework-cisaf_en

⁴⁷ <https://www.gov.uk/government/consultations/network-charging-compensation-scheme-uplift-for-energy-intensive-industries/outcome/proposed-uplift-to-the-network-charging-compensation-scheme-for-energy-intensive-industries-eiis-government-consultation-response>

⁴⁸ <https://www.gov.uk/government/news/government-cuts-electricity-bill-for-10000-manufacturers-in-boost-for-uk-competitiveness>

⁴⁹ <https://www.gov.uk/government/publications/industrial-strategy/industrial-strategy-sector-definitions-list>



ETS support schemes are an implicit recognition that climate policies make European industry uncompetitive

High electricity costs are due to the use of intermittent, low energy density generation, primarily wind and solar

Intermittent generation requires expensive backup or storage

Low energy density generation requires more wires to connect it than equivalent MWh of conventional generation

Wind and solar continue to need generous subsidies

of total ETS auction revenues. 15 member states operated such schemes⁵⁰.

The introduction of the CISAF, BICS and ETS support schemes is an implicit recognition that European energy and climate policies have made European industrial production uncompetitive to the point where intervention is necessary to prevent offshoring.

However, few commentators accurately diagnose the true nature of the problem, too often suggesting the problem lies with wholesale prices that still rely on gas and other fossil fuels. The reality is that gas prices have fallen substantially from their 2022 highs while electricity prices have failed to follow the same trajectory. **The real reason for stubbornly high electricity prices is the transition from large-scale, energy dense dispatchable generation to small-scale, distributed, low energy density intermittent generation.**

Generation that is distributed and has low energy density requires significantly more grid infrastructure to connect it. A conventional power station will be connected to the grid by a single connection while in a wind or solar farm each turbine and each panel must be connected to a central hub and thence to the grid. This simply uses far more wires and ancillary infrastructure than is needed for conventional generation, with the associated costs.

Intermittent generation necessitates investment in backup generation or storage. In fact it is false to characterise the energy transition as a replacement of conventional generation with renewable generation since the conventional generation is still needed for when the wind doesn't blow and the sun doesn't shine. But now conventional generators must recover their costs over fewer hours, raising the cost per MWh.

Many industry groups as well as policymakers fail to understand these dynamics. They note that European countries are paying the price for decarbonisation without capturing its benefits, not realising the financial benefits are a mirage – **the fundamental economics of intermittent low energy density generation are incompatible with a low cost electricity system, despite the near-zero cost of fuel.**

That the renewable generation also continues to require enormous subsidies, most of which are recovered through bills adds to the problem. Recent trends in the UK have been for rising subsidy costs despite historic expectations that subsidies would eventually taper to zero. Contracts for

UK renewables subsidies have increased from 15 to 20 years and have been increasing rather than falling, particularly for wind

The fundamental economics of intermittent low energy density generation are incompatible with cheap electricity despite the near-zero fuel cost

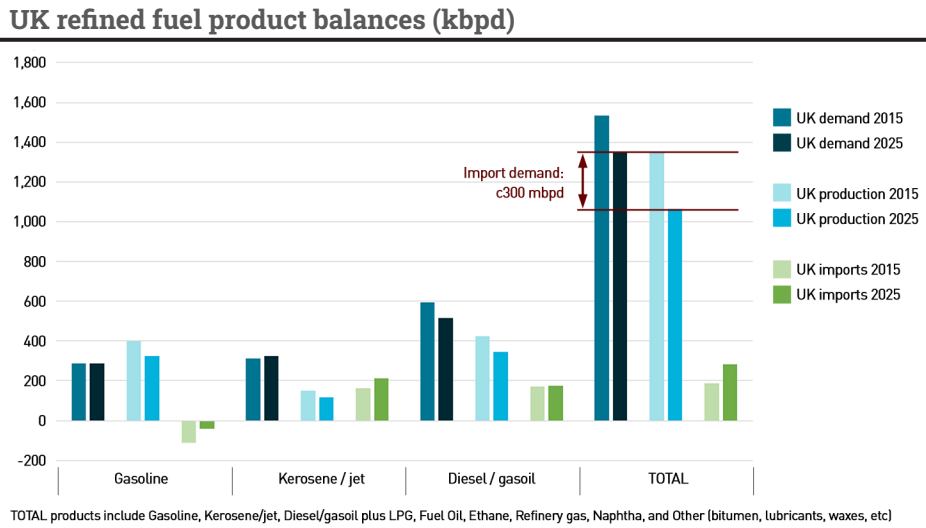
Britain remains broadly self-sufficient in petrol, but is a major net importer of diesel and kerosene

the UK Government's flagship subsidy scheme were increased from 15 to 20 years, which both embeds a long-term cost burden and underlines the fundamental challenge of financing generation that has very high capital costs alongside near zero short-term marginal operating costs.

The unwillingness to confront these economic realities is why Europe faces both structurally high electricity costs and a patchwork of consumer support schemes designed to mitigate the resulting industrial uncompetitiveness compared with peers in the US and Asia, particularly China.

The UK refining sector

The UK's four remaining refineries, Fawley, Humber, Pembroke and Stan-low, currently supply around 85% of domestic fuel needs. The country has already lost fourteen refineries since the 1970s, with Grangemouth and Lindsey both closing in 2025, removing a combined 20% or more of domestic processing capacity within a single year.



Source: UK Government (DUKES)

The structural shift in UK fuel balances following the 2025 refinery clo-





tures is confirmed by UK government data⁵¹. Refinery production fell by 4.8% in 2025 to 48 mt, marginally above the pandemic low of 2020, and just 56% of output in 2000, with the closures of Grangemouth and Lindsey explicitly cited as a primary driver of the decline (both operated during 2025 - Grangemouth closed in April 2025 while Lindsey closed in early August). The UK was a net importer of petroleum products by 15.5 mt in 2025, the highest figure since the UK became a net importer in 2013, representing a 20% increase on 2024 and a 40% increase on pre-pandemic 2019. Product exports fell by 7.6% while imports rose by 3.6% to compensate for reduced domestic production against stable demand.

Diesel continued to account for just under 40% of petroleum product imports in 2025, with the US, Netherlands and Belgium collectively supplying almost 70% of those imports - a supply chain that reflects both the loss of Russian diesel following 2022 sanctions and the structural shortfall in domestic middle distillate production. Jet fuel made up almost one third of product imports, with Kuwait the primary source at 35% of the total, followed by India, Saudi Arabia and the UAE highlighting the UK's dependence on Middle Eastern and Asian refinery output for aviation fuel. The UK remains more than self-sufficient in petrol, exporting 2.7 mt to the Netherlands and 1.9 mt to the US in 2025, but the gasoline surplus that generates those exports is itself a function of the refinery configuration problem discussed elsewhere in this report. UK refineries produce more gasoline than the domestic market needs because their FCC-dominated configuration cannot be redirected away from gasoline production.

The UK will need to import ULSD until the late 2030s, and jet until well past 2050, even if all existing refineries remain in operation. As the Government acknowledged in its February 2026 call for evidence on the future of the downstream oil sector, fuel remains the largest single energy subsector, meeting 47% of UK final energy consumption. The UK has very limited ability to replace domestic refining with imports at short notice without significant cost and supply risk⁵².

The structural consequence is a shift from self-sufficiency to import dependence in products where UK demand is growing or holding steady. **Britain remains broadly self-sufficient in petrol, but is now a substantial net importer of diesel and kerosene - importing 2.5 times and 3.1 times its domestic production respectively in 2024⁵³.** These are the products for which import disruption is most damaging: diesel underpins road freight, agriculture and construction; kerosene is the primary aviation fuel. The 2026 Iran war demonstrated this vulnerability, with diesel prices rising sharply and Parliament questioning whether the UK's fuel security framework was adequate given the closure of Grangemouth and Lindsey, with peers explicitly linking refinery closures and high energy policy costs to the UK's exposure to the disruption.

It is in this context that the regulatory and fiscal treatment of the UK refining sector matters. Policy decisions that affect the cost base of the four remaining refineries, including the design of the UK ETS, the introduction of the UK Carbon Border Adjustment Mechanism ("CBAM") from January 2027, and the treatment of carbon leakage provisions, are not abstract regulatory questions. They have a direct bearing on whether UK refineries remain commercially viable, which in turn determines the degree to which UK fuel supply is met by domestic production or imports from markets that may not always be willing or able to supply at short notice.

The UK now diverges most sharply from parts of continental Europe in terms of hydrocracking capability. Germany and the Netherlands in particular have refinery configurations that include hydrocrackers where the Rotterdam complex and several German inland refineries have invested

more heavily in hydrogen-based conversion than the UK fleet has.

European refineries with hydrocrackers have more flexibility in the middle distillate yield from a given crude slate than UK refineries can achieve with FCC-only conversion.

The broader global context is also shifting in ways that do not favour European refiners. New refining capacity being added in Asia, the Middle East and Africa falls into two distinct categories with different competitive implications. The first is hydrocracker-equipped export refinery capacity, predominantly in the Middle East and India, oriented toward diesel and jet fuel production for global markets. This directly competes with European refiners in the same product markets, offering equivalent or superior middle distillate yields at greater scale and substantially lower cost.

The second is integrated refinery-petrochemical capacity, mainly in China, oriented toward chemicals production rather than transport fuels, and serving genuinely different end markets.

European FCC capacity of around 1.4 mmbpd is dwarfed by North America at 6.3 mmbpd and Asia at 4.5 mmbpd, with growth in FCC additions concentrated in Asia and Africa rather than Europe. Since FCC units are primarily gasoline-oriented, this growth compounds the structural gasoline surplus rather than addressing Europe's middle distillate deficit. **The capacity that would address that deficit - namely hydrocrackers - is being added in the Middle East and India, where it will serve European product markets from a lower-cost base rather than being built in Europe itself.**

Outlook for the remaining UK refineries

The four remaining UK refineries present a varied but collectively precarious picture. Fawley benefits from the financial strength and long-term capital commitment of ExxonMobil, demonstrated by the £800 million FAST investment completed in 2025. Its product slate is now better oriented toward middle distillates than at any point in its history.

Humber is the most technically sophisticated asset in the group, with a unique coking capability that enables it to process heavy sour crudes that other UK refineries cannot economically handle, and a product diversification into specialty coke, sustainable aviation fuels and petrochemicals that insulates it partially from conventional fuel demand decline.

Phillips 66's January 2026 acquisition of Lindsey assets and the December 2025 announcement of a further capital project signal continued owner commitment, while Pembroke benefits from a strong logistics position, a robust owner balance sheet, and independent benchmarking that places it among the more resilient refineries in Valero's global portfolio under long-run demand scenarios.

Stanlow carries the most financial and operational risk of the four: a heavily leveraged balance sheet, a governance history that has attracted regulatory and journalistic scrutiny, and a decarbonisation programme whose central investment remains conditional on government support after four years of negotiation.

All four sites face the same structural headwinds - declining European product demand, rising ETS compliance costs, intensifying competition from larger and lower-cost refiners in Asia and the Middle East, and the recurring capital demands of the turnaround cycle on ageing assets. The closures of Grangemouth in April 2025 and Lindsey in August 2025 demonstrated that these pressures can crystallise quickly and that the consequences for fuel supply, employment and regional economies are not easily reversed.

⁵¹ https://assets.publishing.service.gov.uk/media/6a69f02d16bc92f51e1a4337/DUKES_2026_Chapter_3.pdf

⁵² <https://www.gov.uk/government/calls-for-evidence/future-of-the-uk-downstream-oil-sector/future-of-the-uk-downstream-oil-sector-call-for-evidence>

⁵³ https://assets.publishing.service.gov.uk/media/68dbe4c7c487360cc70c9f5f/DUKES_2025_Chapter_3.pdf



Whether further closures occur in the coming years will depend on the interaction of margin cycles, turnaround timing, owner appetite for continued capital commitment, and, whether the UK government treats domestic refining capacity as a strategic asset worth sustaining or allows market forces, amplified by asymmetric carbon costs, to determine the outcome.

Details of the individual refinery configurations and financial performance can be found in Appendix 3.

UK emissions trading scheme

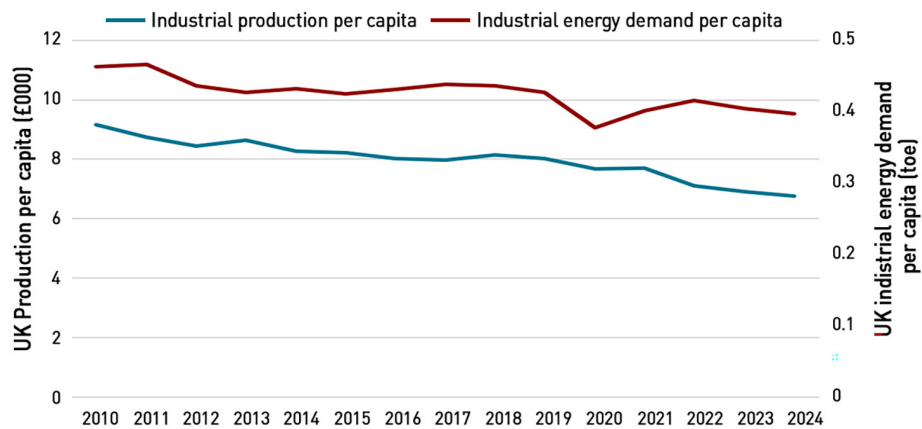
Overview of the UK ETS

The UK Emissions Trading Scheme (“ETS”)⁵⁴ is the UK’s carbon market, created on 1 January 2021 after the UK left the EU ETS following the UK’s departure from the European Union (“Brexit”). The EU ETS was launched in 2005 as the world’s first large-scale carbon market. The UK participated from the outset until Brexit. Indeed, the market was seen as a victory for Anglo-Saxon capitalists led by the UK which argued for a market-based mechanism rather than an EU-wide carbon tax which was preferred by countries such as France.

The ETS seeks to apply a cost to activities such as fossil fuel power generation, manufacturing and air travel that, according to the Government, “better reflects the cost to society of the emissions they produce”.

Participants in the ETS must acquire enough allowances to cover their emissions each year, with this need for allowances creating a market in which they can be bought and sold. The ETS covers power, heavy industry and aviation, accounting for roughly a quarter of UK territorial emissions and has over 1,000 participants. Allowances can be obtained through free allocation, government auctions or secondary market purchases. Auctions are the primary means by which companies acquire UKAs (see Appendix 4 for more details).

**Deindustrialisation:
declining UK industrial production and energy demand**



Source: Office for National Statistics UK Index of Production time series, Office for National Statistics population data and estimates, DESNZ Energy Consumption in the UK (ECUK): Final Energy Consumption Tables

In practice, carbon costs are not the only drivers of offshoring that leads to carbon leakage - high energy costs aside from the impact of carbon pricing have contributed to significant levels of deindustrialisation in the UK.

⁵⁴ <https://www.gov.uk/government/publications/uk-emissions-trading-scheme-uk-ets-policy-overview/uk-emissions-trading-scheme-uk-ets-a-policy-overview>

The ETS aims to apply a cost to carbon dioxide emissions that reflects their cost to society...

...but there is no attempt to account for the benefits to society of the activities producing those emissions

Refineries don't just emit greenhouse gases. They deliver energy security, resilience to market shocks, economic value and strategic optionality

Refined products are crucial for transport and chemical feedstocks

Almost every medication licenced in the NHS is made from petrochemicals refined from crude oil, including chemotherapy drugs

The CBAM excludes refined products leaving the sector exposed to carbon leakage

Carbon pricing

The Government explicitly states that the purpose of carbon pricing is to “apply a cost to activities like fossil fuel power generation, manufacturing and air travel that better reflects the cost to society of the emissions they produce”. This is an incomplete framing as it ignores the benefits of using fossil fuels. A better framework would be one that sought to reflect the net social impact of an activity, not just its negative externalities.

The refining sector (and energy production more broadly) doesn't just emit greenhouse gases, it also delivers energy security (reduced dependence on imports), system resilience (local capacity in shocks or crises), economic value (jobs, tax base, industrial capability), and strategic optionality (ability to respond to geopolitical disruption). These are positive externalities or public goods and are also not fully priced into markets.

Under the existing, one-sided framework, if leakage is not adequately prevented, for example where UK refining faces a carbon cost, but imports do not face an equivalent cost, the policy effectively assumes that a tonne of emissions avoided in the UK is a net benefit, regardless of where production moves. If production shifts overseas, where emissions are the same or higher, and the UK loses domestic capacity then global emissions may not fall, and positive domestic externalities are lost. This is not just inefficient, it actively reduces welfare.

Furthermore, refineries are not just “emitters”, they are critical infrastructure for transport fuels (including aviation and defence), providers of feedstocks for petrochemicals, plastics, pharmaceuticals and part of emergency supply chains (e.g. during supply disruptions). These are strategic goods where markets alone may not deliver optimal outcomes. A purely carbon-cost-based framework treats refining as a standard industrial activity and ignores its systemic importance.

As a result the Government becomes exposed to calls for ad hoc sector-specific support in order to protect strategically important industries, when a more coherent policy approach would seek to balance positive as well as negative externalities from the outset.

Harmonisation with the EU ETS and the Carbon Border Adjustment Mechanism

The UK’s Carbon Border Adjustment Mechanism (“CBAM”) is a new tax⁵⁵ which “will ensure that highly traded, carbon intensive goods which are imported into the UK face a comparable carbon price to that paid by manufacturers producing the same goods in the UK”. Goods manufactured in the UK are subject to the ETS. The CBAM will apply from 1 January 2027 to the following industrial sectors: aluminium, cement, fertiliser, hydrogen, iron and steel.

Neither the EU nor UK CBAM currently extends to refined products, leaving refineries exposed to domestic carbon costs while competing against imports that do not face an equivalent charge.

The EU CBAM forms part of a broader industrial and climate policy framework linked to the EU ETS, whereas the UK approach is being developed primarily as a tax instrument by HM Treasury. This difference has contributed to a slower and less detailed articulation of the UK mechanism, with industry raising concerns about uncertainty over its eventual design and operation.

The effectiveness of the CBAM in preventing carbon leakage will depend on both coverage and implementation. Partial sectoral coverage risks

⁵⁵ <https://www.gov.uk/government/publications/introduction-of-carbon-border-adjustment-mechanism/carbon-border-adjustment-mechanism>

CBAMs are inflationary

“leakage within the boundary”, where emissions-intensive intermediate products are imported and then processed within the UK. More broadly, CBAMs introduce additional costs into supply chains, which are likely to be passed through to consumers, contributing to upward pressure on prices, particularly in construction and manufacturing, ultimately driving inflation.

Also, the CBAM only addresses carbon leakage on imports that is the displacement of domestic production by lower-carbon-cost imports. However there is an equivalent export carbon leakage the CBAM does not address, where domestically produced goods bear carbon costs that make them uncompetitive in third country export markets relative to producers not subject to equivalent carbon pricing. The UK Government has no current proposals to address export carbon leakage, meaning UK energy-intensive producers, including refineries, will remain disadvantaged in export markets regardless of CBAM implementation.

Proper carbon accounting would apply carbon costs to all consumption, reflecting the true cost of decarbonisation to the economy...

The relatively modest inflationary impact identified in much of the CBAM literature reflects its limited sectoral scope. If the CBAM were extended to cover a wider range of goods the inflationary impact would be materially higher.

This highlights a central limitation of net zero policy, which focuses on territorial production emissions rather than emissions associated with consumption. This incentivises offshoring of manufacturing in favour of imports. The CBAM partially addresses this, but only for a narrow set of sectors, and only for imports – there is no equivalent protection against export carbon leakage.

A fully consumption-based approach would apply carbon costs across all imports, exposing the true cost of decarbonisation. That has not been pursued, in part because the resulting increase in consumer prices would be more visible and politically sensitive.

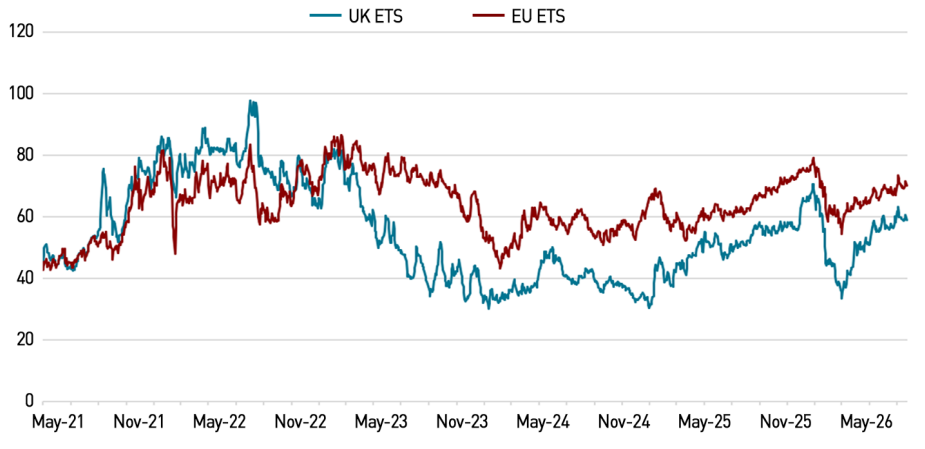
The UK Government has indicated that it intends to pursue closer alignment, or “linking”, between the UK ETS and the EU ETS, arguing that alignment is necessary to reduce the risk that UK exports face additional carbon costs at the EU border.

...but this would cause major increases in consumer prices which would be politically sensitive

Expected ETS harmonisation has already caused a material increase in UK carbon costs

This has added to the competitive challenges of the UK refining sector

UK and EU ETS prices (£ /tonne)



Source: Bloomberg, ECB EUR/GBP exchange rate

However, full harmonisation of the UK and EU ETS is not necessary for CBAM purposes, as the EU CBAM allows importers to deduct verifiable carbon costs already paid in the country of origin from their CBAM liability. In practice, UK exporters subject to the UK ETS will only face a CBAM charge to the extent that the carbon price they paid in the UK is below the EU ETS price. The EU CBAM does not require identical ETS design or architecture, just that carbon pricing is measurable, verifiable, and attributable to the goods concerned, conditions the UK ETS meets.

The Government's approach would remove the need for CBAM adjustments. This is a legitimate objective for UK industries with significant relevant exports to the EU such as steel, aluminium, cement and hydrogen. However, these sectors represent only a subset of UK ETS participants. For industries that do not materially export CBAM-covered goods to the EU, the CBAM argument for alignment does not apply. In such cases, harmonisation, which implies price convergence with the EU ETS, would increase carbon costs without providing a corresponding benefit.

Market expectations of alignment are already increasing UK carbon prices. In February 2025, following Keir Starmer's ETS linking announcement, UKA prices rose by approximately one third. The current price differential between UK and EU allowances remains material (of the order of £10–15/tCO₂), implying that convergence would impose a significant additional cost burden across much of the UK ETS-covered economy.





Impact of the ETS on UK energy intensive industries

The impact of the ETS on UK industry has been significant. According to EU and DESNZ compliance data, 292 UK sites out of 1,702 closed on the compliance register under the EU ETS between 2008 and 2020⁵⁶ while a further 183 have closed under the UK ETS since 2021 out of a total number of 1,415 registered sites⁵⁷. This excludes the closures of the Lindsey and Grangemouth refineries, which will appear in future data releases. 31 of the sites closed since 2021 were electricity generators.

Analysis of free allowance allocations provides further evidence of industrial contraction. Total free allowances issued under the UK ETS fell from 37.8 million tonnes in 2021 to just 23.6 million tonnes in 2026, a reduction of 38%⁵⁸. It's tempting to attribute this reduction to planned cuts to force decarbonisation or efficiency gains, except no such reductions have yet been implemented in the UK ETS - the calculation basis for free allocations has not changed since 2021.

This means the reduction is purely due to lower output from registered sites or site closures, and is direct evidence of deindustrialisation: the UK is producing fewer goods year-on-year, and the largest reduction in recent years is the loss of 4.6 million allowances following the closure of the Port Talbot blast furnaces in 2024.

The structure of the market includes a second ratchet effect where any reduction in emissions from the site, whether arising from efficiency improvements, partial facility closure, or temporary output reductions driven by market conditions, results in a reduced allocation in future years. This inhibits any future increase in production or reversal of mothballing on the basis that the associated emissions must now be covered by allowances bought in the market rather than from the free allocation. This further increases operating costs and makes recovery less likely. The market is designed to make deindustrialisation permanent.

How carbon pricing impacts the UK refineries sector

The UK refining sector is exposed to carbon pricing under the UK ETS as an energy-intensive industry with significant direct emissions from refining processes. UKAs create a direct cost which feeds into refining margins. While the sector receives free allocation to mitigate carbon leakage risk, this allocation is partial and declines over time, so refiners are increasingly exposed to the carbon price.

Between January 2025 and January 2026, the UK ETS price increased £18.80 per tonne, adding £75.2 million per year in cost burden to UK refining based on the number of allowances refineries are required to surrender.

Based on the average ETS price over the past year, the total net ETS cash cost to the four UK refineries is approximately £200 million per year, with the gross burden - that is the full competitive disadvantage relative to non-ETS refiners - being approximately £540 million per year.

The oil refining sector is the third largest purchaser of ETS allowances after electricity and aviation, and the largest that cannot pass those costs through to the consumer. The three largest sectors that cannot pass costs on are all oil and gas related: refining, crude oil production and natural gas production. All 90 other sectors, including steel, cement, ceramics and glass jointly make up less than the combined total for the refining sector.

56 https://climate.ec.europa.eu/document/download/2d3e055d-ba0e-46db-b4c1-e3a9210d7ddb_en?filename=compliance_2020_code_en.xlsx

57 <https://reports.view-emissions-trading-registry.service.gov.uk/ets-reports.html>

58 <https://reports.view-emissions-trading-registry.service.gov.uk/ets-reports.html>

The UK is producing fewer goods year-on-year

The total net ETS cash cost to the four UK refineries is c£200 million per year...

...the full competitive disadvantage relative to non-ETS refiners is c£540 million per year

Oil refining is the 3rd largest purchaser of ETS allowances...

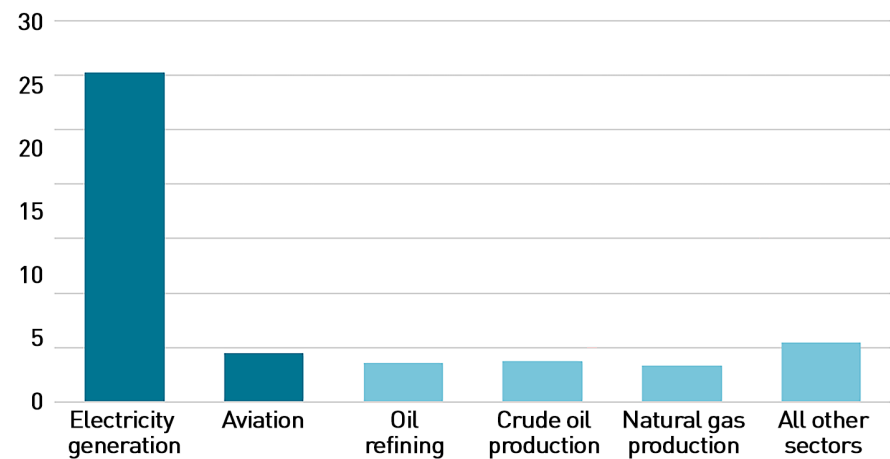
...and the largest that cannot pass those costs through to consumers

Refineries compete on thin margins - even modest cost increases erode competitiveness

Carbon pricing often fails to reduce emissions - it displaces them geographically

Unlike the power sector, where costs are largely passed through to consumers through wholesale electricity prices, refiners operate in internationally traded product markets where they are subject to international competition. Refined products such as diesel, gasoline and jet fuel are widely traded and largely fungible, so UK refiners have limited ability to pass through carbon costs, because competing refineries outside Europe are not subject to equivalent carbon pricing.

Purchases of UK ETS allowances by industry sector 2025 (mt CO₂)



Source: UK Emissions Trading Registry

Refineries compete on thin margins and are highly sensitive to cost differentials where even modest cost increases, including carbon, can erode competitiveness. In addition, periodic turnarounds which involve significant capital expenditure create a recurring decision point on whether continued operation is economically viable. Where margins are under pressure, these events can become “go/no-go” decisions on the future of a site.

“... we are currently paying £70 million to £80 million a year in CO2 costs. That will go up to £150 million in the next four or five years, and our competitors are not paying any. That is the cost delta that we are suffering versus our competition, and that is what is causing refineries to shutter in the UK. We have lost two recently. You are therefore effectively driving even more imports to come in, and they can compete against us because they are not paying the CO2 costs,”

- Paul Greenwood Managing Director, ExxonMobil UK⁵⁹

At the same time, refining is capital intensive and subject to long investment cycles, meaning that once capacity is lost it is unlikely to be replaced. These factors make the sector particularly vulnerable to international competition and to carbon leakage.

Carbon pricing creates an asymmetric outcome: UK refineries incur carbon costs under the ETS, while imported refined products often do not face an equivalent charge which creates an incentive to substitute domestic production with imports. Where those imports originate from jurisdictions with higher emissions intensity, due to differences in fuel mix, efficiency or environmental standards, there will be higher **global** emissions despite lower **UK** emissions.

59 <https://committees.parliament.uk/oralevidence/16627/pdf/>

Carbon pricing often fails to reduce emissions - it displaces them geographically. The CBAM does not address this issue for the refining sector and other sectors that are outside its scope.

Is CCS a viable solution to the problem of carbon costs?

CCS has not to date proved to be a viable route to reducing emissions....

Carbon capture and storage ("CCS") is frequently cited as a means by which UK refineries could reduce ETS compliance costs while maintaining production. Of the four remaining UK refineries, only Humber and EET have CCS projects directly targeting refinery process emissions.

Phillips 66's planned post-combustion capture plant would attach Shell's Cansolv technology to the FCC unit flue gas stack, capturing up to 0.5 million tonnes of CO₂ per year, approximately equivalent to the refinery's direct ETS liability, and transporting it for storage under the North Sea via the Viking CCS pipeline. This project is on hold pending a government revenue support agreement. EET is planning to capture refinery emissions for storage in HyNet via the ICC project, (distinct from its blue hydrogen scheme) for sequestration in depleted gas fields in Liverpool Bay⁶⁰.

...projects rely on hydrocarbon production / processing for economics (eg enhanced oil recovery)...

EET Fuels' HyNet blue hydrogen programme is closely integrated with Stanlow's own decarbonisation plans. The refinery is a major planned offtaker of hydrogen from HPP1 and EET has already installed a hydrogen-ready furnace at Stanlow. This is currently running on refinery off-gas, but is designed to transition to 100% low-carbon hydrogen when HPP1 comes online⁶¹. Together with the ICC carbon capture project described above, EET targets a 95% reduction in Stanlow's direct emissions by 2030 - approximately 1 million tonnes from industrial carbon capture and a further 1 million tonnes from hydrogen fuel switching. Both the hydrogen and carbon capture projects remain contingent on government revenue support agreements that have not been secured after several years of negotiation, and neither has reached a Final Investment Decision.

...or they need significant government subsidies....

ExxonMobil had been pursuing a similar adjacent scheme at Fawley through the Solent Cluster, a proposed blue hydrogen plant that would have produced hydrogen from natural gas with associated CCS, capturing approximately 2.7 million tonnes of CO₂ per year for storage under the English Channel^{62,63}. This scheme has subsequently been cancelled with ExxonMobil's UK then Managing Director Paul Greenwood confirming to the Energy Security and Net Zero Select Committee that the decision reflected policy failure rather than technical or commercial unviability.

This means UK refineries continue to accumulate ETS compliance costs while the investments that might reduce them remain conditional on policy decisions that have yet to be taken. This is consistent with the broader European picture where decarbonisation plans exist but investment decisions are conditional on policy frameworks that have not yet been finalised.

...which in the UK have not been forthcoming despite the government setting aside significant sums for CCS support

The global evidence on post-combustion CCS - the technology relevant to refinery applications since around 50% of refinery emissions can only be captured post-combustion - illustrates both the potential and the conditions required for success. The closest industrial analogue to the Humber CCS project is Shell's Quest facility at the Scotford oil sands upgrader in Alberta, Canada. This captures CO₂ from hydrogen production process streams at an oil processing complex, though it uses pre-combustion capture from a relatively concentrated CO₂ stream rather than post-combustion capture from mixed flue gas, making it technically less challenging

⁶⁰ <https://www.eetfuels.com/eet-fuels-enters-front-end-engineering-design-stage-and-apoints-toyo-india-for-industrial-carbon-capture-project/>

⁶¹ <https://www.essar.com/inthenews/essar-energy-transitions-hydrogen-ready-furnace-now-powering-eet-fuels-stanlow-site/>

⁶² <https://www.exxonmobil.co.uk/community-engagement/key-locations/fawley-operations/fawley-hydrogen-project>

⁶³ <https://efwd.energyvoice.com/insights/ccus/exxonmobil-holds-out-hope-for-fawley-decarbonisation-hub>

than the Humber application.

Quest began operations in 2015 at a capital cost of approximately C\$1.35 billion (£700 million), around two thirds of which came from the Canadian and Albertan governments. It had a designed capture rate covering around a third of the facility's total CO₂ emissions^{64,65}. Its operating costs per tonne of captured CO₂ rose from C\$ 34.70 in 2016 to C\$ 62.54 in 2023, an increase of 80% over seven years – reflecting the learning curve that accompanies first-of-kind industrial CCS deployment.

Two further post-combustion capture projects - Canada's Boundary Dam 3 power station and the US Petra Nova project - demonstrate both the technical feasibility and the economic fragility of the technology. Boundary Dam, commissioned in 2014, took several years to reach its designed capture capacity, illustrating that post-combustion CCS from mixed flue gas involves a significant operational learning curve⁶⁶. Petra Nova, which achieved its designed capture rate of 92.4% during operation, demonstrating that the technology can perform as intended, but was shut down in 2020 when the oil price revenues underpinning its business case collapsed. NRG Energy subsequently sold its 50% stake for \$3.6 million against a construction cost of approximately \$1 billion^{67,68}. It was eventually restarted in 2023 under new ownership.

Both Boundary Dam and Petra Nova rely on enhanced oil recovery for their economics, a model which is problematic in a net zero context, and one that the Humber CCS project explicitly avoids by designing for permanent geological storage. This design removes the revenue stream that gave those projects their commercial rationale, making government support the only available mechanism to underwrite the economics.

The consistent lesson across all three projects is that post-combustion CCS is technically challenging, although it can work, and its commercial viability depends entirely on sustained revenue support mechanisms outside the operator's control.

In the UK context this is a government support framework - or subsidy - that remains to be agreed. The government has committed £21.7 billion over 25 years to CCUS projects in HyNet and the East Coast Cluster, with the Public Accounts Committee warning that total liabilities could reach £34 billion and that approximately 75% of costs will be recovered through additions to consumer energy bills rather than general taxation⁶⁹.

⁶⁴ <https://sequestration.mit.edu/tools/projects/quest.html>

⁶⁵ <https://www.shell.com/business-customers/catalysts-technologies/resources-library/quest-carbon-capture-plant.html>

⁶⁶ http://ieefa.org/wp-content/uploads/2021/04/Boundary-Dam-3-Coal-Plant-Achieves-CO2-Capture-Goal-Two-Years-Late_April-2021.pdf

⁶⁷ <https://www.energy.gov/fe/petra-nova-wa-parish-project>

⁶⁸ <https://ieefa.org/resources/ill-fated-petra-nova-ccs-project-nrg-energy-throws-towel>

⁶⁹ <https://publications.parliament.uk/pa/cm5901/cmselect/cmpubacc/351/report.html>



Policy implications

The UK boasts significant reductions in emissions, but much of these were achieved in the first instance by a switch from coal to gas in the power sector that was motivated by economics and resource management rather than climate concerns. Subsequently, deindustrialisation has been the dominant driver of falling energy demand and the associated emissions cuts.

The UK refinery sector is particularly vulnerable. The industry is capital intensive, suffers from high energy costs, and is not within the CBAM meaning that UK and European refineries face an additional disadvantage relative to international peers. Even against their European competitors, UK refineries are disadvantaged by less government support, less extensive pipeline networks connecting them to their markets, and less flexible configurations. With only four refineries left having lost two in the past year, the UK is increasingly reliant on imports to meet refined product demand, reducing energy security accordingly.

If the UK refinery sector is to avoid further contraction, a political reset is needed.

Domestic refining capacity as a strategic asset

The surviving UK refineries face a combination of structural headwinds: declining domestic product demand driven by deindustrialisation, margin pressure from larger and lower-cost competitors, rising carbon compliance costs and the recurring capital demands of an ageing asset base. The closures of Grangemouth and Lindsey demonstrated that once a refinery closes, the capacity, skills and supply chain relationships it supported are lost. The question for policymakers is not whether domestic refining matters - the Hormuz disruption provides a clear answer to that - but what weight to give it when it conflicts with other policy objectives.

The UK is already a substantial net importer of diesel and kerosene, the products that underpin road freight, agriculture, construction and aviation. That import dependence is structural and growing. Policymakers face a choice between treating this as an acceptable feature of a globalised energy market, or as a strategic vulnerability requiring active management. The Iran war led to sharp rises in crude oil and diesel prices and concerns over aviation fuel supply. The market will not itself provide the resilience that the government will be expected to deliver in a crisis.

The asymmetry of carbon pricing

The UK ETS imposes carbon costs on domestic refiners that are not shared by competing refineries that supply the marginal imported barrel into UK markets. Refined products are not covered by the CBAM, and the CBAM's current architecture does not address this asymmetry even for sectors it does cover. The consequence is a structural competitive disadvantage for domestic producers relative to importers.

Embedded in the carbon market is a ratchet mechanism that further erodes competitiveness. Where an industrial site reduces output in response to high costs for example by mothballing certain equipment, its free carbon allowance allocation will shrink accordingly. This acts as a disincentive to restarting this production since the associated carbon emissions would need to be purchased in the market rather than being covered by free allowances at significant additional cost.

This makes temporary output reductions more likely to become permanent, accelerating the trajectory toward closure. When this decarbonisation feature interacts with weak market conditions and strong compe-

titution it has consequences that extend beyond what carbon pricing was intended to achieve.

Carbon leakage and the limits of territorial accounting

The theoretical justification for carbon pricing is that it reduces emissions. For that to hold in practice in the refining sector, the reduction in domestic production must not be replaced by imports from refineries with equivalent or higher emissions intensity, otherwise UK territorial emissions fall while global emissions remain unchanged or increase.

However, carbon leakage is a real and material risk in the refining sector: new capacity is being added in the Middle East and Asia at scale, often with lower environmental standards and higher emissions intensity than the UK refineries it displaces. The UK government acknowledges the risk of carbon leakage, but the current response of free allocations and a future CBAM is inadequate for a sector that neither receives full protection from free allocation nor falls within CBAM scope.

Policymakers face a choice between maintaining that territorial carbon accounting is the appropriate framework, and accepting the leakage implications that follow, or developing a more comprehensive approach to embedded emissions that treats consumption as the relevant unit of account. The latter would require either expanding the CBAM to cover refined products, or simply exempting the sector from carbon pricing or indeed abolishing the carbon pricing framework altogether.

This may sound radical, but the carbon pricing regime is arguably failing to deliver operational emissions reductions: emissions either do not fall or fall because production stops completely. This is not what the scheme was intended to achieve. The ability of UK refiners to deliver meaningful further emissions reductions that are not already incentivised through the benefits of higher efficiency is minimal, so the regime serves no useful purpose while causing significant harm. In fact, European refineries made significant efficiency improvements between 1992 and 2010⁷⁰, before the introduction of the ETS – efficiency gains have clear benefits in any case, and do not require incentives to be implemented.

The current position, where domestic refiners bear carbon costs that imported products do not, is both unfair and harmful to British interests. A more coherent policy choice would be to recognise the limited environmental benefits of the ETS in the refining sector and exempt it, while applying similar calculus to other parts of the economy.

The interaction of ETS linking and competitive position

The proposed linking of the UK ETS with the EU ETS is presented primarily as a CBAM solution that removes the risk that UK goods face additional carbon charges at the EU border. For sectors with significant CBAM-covered exports to the EU, this rationale is sound. But for UK refineries, which do not face material EU CBAM exposure on refined products, the argument for alignment is weaker.

The cost of alignment as UK carbon prices rise toward EU ETS levels is real and applies across all ETS participants, while the benefit of alignment is concentrated in sectors with EU export exposure that refineries do not share.

Further, full harmonisation of the UK and EU ETS is not strictly necessary for CBAM purposes, and the Government's case for pursuing it is weak. The EU CBAM Regulation does not require identical ETS design or architecture; rather, it requires that carbon pricing be measurable, verifiable, and attrib-

⁷⁰ https://www.concawe.eu/wp-content/uploads/rpt_12-03-2012-01520-01-e.pdf

utable to the goods concerned, conditions which the UK ETS is capable of meeting. The disadvantages of harmonisation outweigh any benefits and therefore the plans should be abandoned.

Forcing UK refiners to bear carbon costs which imported products do not face is unfair and harmful to British interests

A more coherent policy choice would be to recognise the limited environmental benefits of the ETS and exempt the refining sector...

...and potentially abolishing it altogether

Decarbonisation investment and the funding gap

All four remaining UK refineries have announced or explored direct or indirect decarbonisation investments - CCS at Humber to directly decarbonise refinery operations, blue hydrogen at Stanlow and Fawley, and green hydrogen at Fawley all aimed at supporting local decarbonisation. Valero is reportedly exploring the use of green hydrogen to decarbonise its operations from a proposed third party scheme close to its refinery⁷¹. None has progressed to a Final Investment Decision, and all are contingent on government revenue support frameworks that have not been finalised after years of negotiations.

The government has committed £21.7 billion over 25 years to CCS cluster projects, with the Public Accounts Committee warning that total liabilities could reach £34 billion, the bulk of this being recovered through energy bills. Whether this represents a sound use of public and consumer resources depends on assessments of the technology's readiness, the counterfactual of alternative decarbonisation pathways, and the strategic value of retaining domestic industrial capacity that CCS would enable.

However, this sizeable commitment from the Government explicitly recognises that decarbonising with CCS is uneconomic based on the ETS costs. ETS costs are high, but not nearly high enough to incentivise decarbonisation across much of industry, including refineries – if they were, it would not be necessary to provide £billions in CCS subsidies. The ETS is too low to deliver decarbonisation but too high to allow many industries to be competitive, forcing their premature closure.

What the evidence does not support is the assumption that CCS will resolve the structural competitive disadvantage that UK refineries face on carbon costs in the near term. The projects that exist are at early stages, the funding frameworks are unresolved, and the global track record of post-com-

Net zero policies require carbon costs to be applied to UK producers...

...this can help make them uncompetitive, forcing many to close...

...so domestic production is replaced with imports, often with higher carbon intensity...

...which is bad for energy security and bad for the climate

bustion CCS at industrial scale is somewhat mixed. Delivery timelines and costs regularly exceed initial expectations, while capture rates have disappointed.

In the interim, refineries continue to accumulate ETS compliance costs, turnaround cycles continue to create invest-or-exit pressure points, and the window in which investment decisions can be made on commercially viable terms is narrowing.

The underlying trade-off

The central tension in UK refining policy is between two objectives that pull in opposite directions. Net zero requires that carbon costs be applied to domestic producers. Energy security requires that domestic production capacity be maintained. Where those objectives conflict as they do for energy-intensive industries that cannot pass carbon costs through to consumers, the carbon pricing framework does not resolve the tension, it simply allows it to play out through market forces, with the consequence that domestic capacity declines and import dependence increases.

That outcome may be acceptable if policymakers have made a considered judgement that import dependence is manageable and that the security risks are tolerable. But there is little evidence of such an analysis. Indeed, both the initial shock of the Ukraine war in 2022 and the Iran war of 2026 suggest that judgement deserves to be tested more explicitly.

A policy framework that depletes domestic refining capacity while failing to address the carbon leakage implications of the imports that replace it does not serve either the decarbonisation objective or the supply security objective.

This is the central failure of carbon pricing: by making domestic industry so uncompetitive that it closes in favour of more carbon intensive capacity elsewhere in the world, it raises global emissions while inflicting irreversible economic damage to the UK.

⁷¹ <https://www.gov.wales/sites/default/files/consultations/2021-01/hydrogen-in-wales-baselining-document-pictures.pdf>





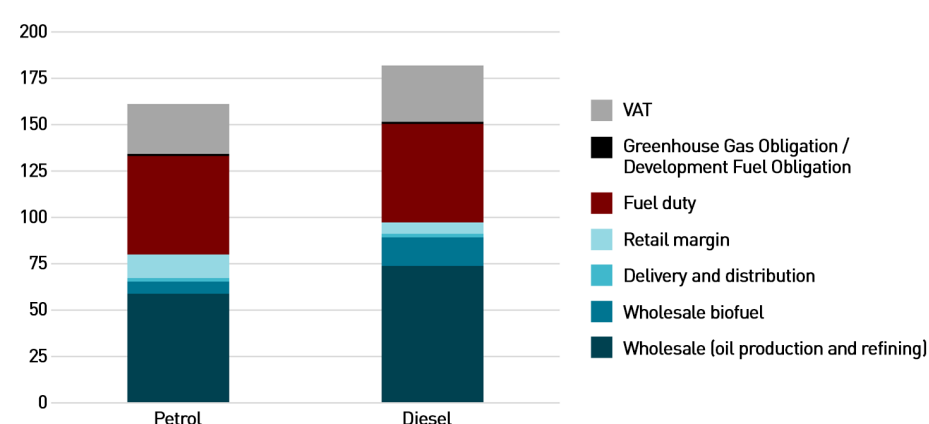
Appendix 1 – the price of fuel

The initial interest in refining is often the impact on politically sensitive pump prices for petrol and diesel. Every litre of fuel sold on the forecourt is the end product of a supply chain that spans crude oil extraction, international shipping, refining, distribution and retail, and reflects each of these stages.

The average retail price of ultra low sulphur unleaded petrol in the week commencing 17 August 2026 was 161 pence per litre⁷². Of this, Fuel Duty (a flat excise duty frozen at 52.95 p/l since March 2022) accounted for 52.95 p/l. VAT at 20% added a further 27 pence, calculated on the total pump price including Fuel Duty, meaning motorists pay VAT on the duty itself⁷³. Together, duty and VAT represent roughly 50% of the pump price.

The pump price of ultra low sulphur diesel in the same period was 181 p/l, of which 52.52 pence was fuel duty and 30 pence was VAT, with the total tax being 45% of the pump price. Tax is therefore about 83 p/l.

Petrol and diesel pump price breakdown (pence per litre)



Source: RAC latest daily pump prices

The remaining 50%, what DESNZ terms the “basic price” covers the wholesale fuel price, delivery and distribution costs and retail margin but not tax and duty. Within this, crude oil typically accounts for the largest share, followed by the refining margin (the “crack spread” between the price of crude entering a refinery and the refined products leaving it), distribution and logistics costs, and finally the forecourt retailer’s margin.

The CMA’s enhanced road fuel monitoring report measures what it calls the “refining spread” as the difference between the crude oil cost and the ex-rack wholesale price set by refineries and importers, which has historically been in the range of 5–15 pence per litre under normal market conditions (ex-rack refers to the wholesale price of a refined product as it exits the refinery). This is not the typical definition of a refining spread. The true refining margin after all costs is close to zero in mid-cycle conditions and generally positive in strong margin years for example during the market shocks of 2022 and 2026.

The CMA’s measure does not capture the full economics of refining as it excludes refinery operating costs, the cost of delivering crude to the refinery, the premium or discount of the actual crude slate to the Brent benchmark and the crude volume consumed in the refining process itself (typically 2–5% of feedstock volume, this is analogous to the consumption of coal in a blast furnace where the coal is both fuel for the furnace and a feedstock for the chemical reaction). The CMA’s refining spread is therefore better

⁷² <https://www.gov.uk/government/statistics/weekly-road-fuel-prices>

⁷³ <https://www.gov.uk/tax-on-shopping/fuel-duty>

Around half of the UK pump price is tax – c79p /litre for petrol and 85p /litre for diesel

Motorists pay VAT on Fuel Duty as well as on the underlying cost of the fuel

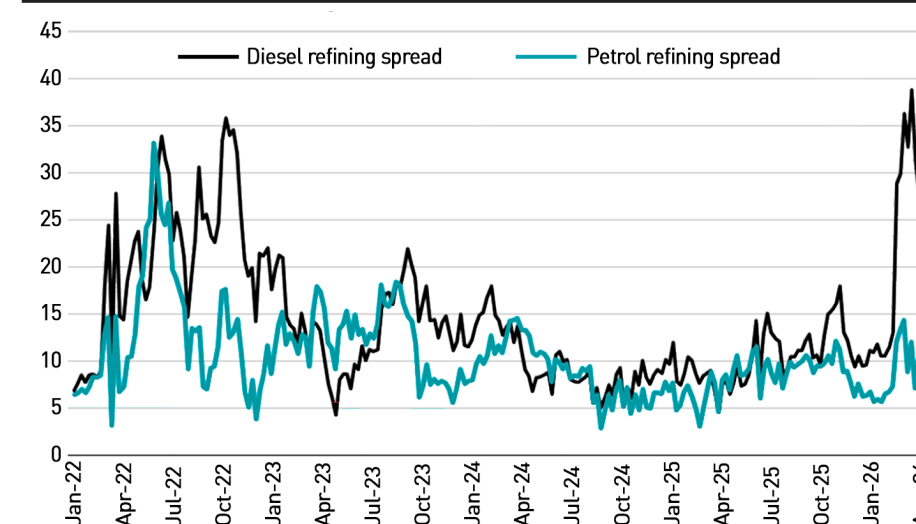
The CMA found no evidence that excessive UK refinery profits were imposing unnecessary costs on consumers

Higher refining margins during market shocks compensate for periods when margins are low or negative

understood as a price signal reflecting market conditions for the marginal barrel than as a measure of refinery profitability or the true cost of the refining function in the supply chain.

But refining is not just a question of the pump price of fuel - it is also a security of supply question, because refineries determine what products are available, in what quantities, at what locations, and with what response time when markets are disrupted.

Petrol and diesel refining spreads (pence per litre)



Source: CMA analysis of Department for Energy Security and Net Zero, Platts, Bloomberg and Bank of England data

But refining is not just a question of the pump price of fuel - it is also a security of supply question, because refineries determine what products are available, in what quantities, at what locations, and with what response time when markets are disrupted. The strategic importance of refining is much greater than its direct contribution to the retail price – domestic refineries determine a country’s ability to meet demand from domestic refining rather than imports and this affects security of supply, resilience and exposure to international product markets.

“...the UK refining industry faces stiff competition from an increasing number of refiners across the world; overall margins over the five years preceding the market study had been modest and there had been no overall excessive profits for UK refiners; and the increased margins observed in the first half of 2022 were short-term and were cancelled out by low or negative margins in other periods. We therefore concluded that there were no deficiencies in competition in the UK refining market that were leading to unnecessary costs for consumers,”

- Competition and Markets Authority,
Enhanced road fuel monitoring report: May 2026

It is worth noting the recent swings in retail margins – that is the profit margins of fuel retailers (petrol stations). In March after an escalation in the Iran conflict, UK Government ministers began to warn that profiteering by fuel retailers would not be tolerated, despite there having been insufficient time for any such behaviours to be reflected in market data. The Com-

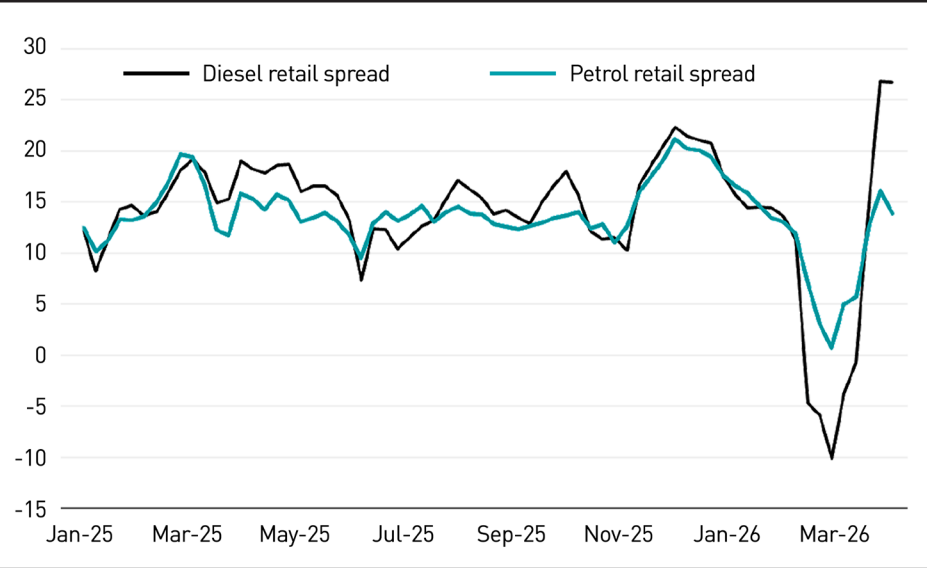
Refining matters more to UK energy security than its relatively small contribution to the pump price

Domestic refining determines how much UK fuel demand can be met without relying on international product markets

petition and Markets Authority (“CMA”) was instructed⁷⁴ by the Chancellor of the Exchequer to monitor the fuel market for signs of profiteering, saying she would “not tolerate any company exploiting the current crisis to make excess profits at customers’ expense”.

In its May *Enhanced road fuel monitoring report*, the CMA found that retail margins for petrol and diesel were “broadly unchanged” between February 2026 and March 2026 indicating that “there has not been a widespread issue of retailers earning higher margins since the beginning of the conflict in the Middle East”.

Petrol and diesel retail spreads (pence per litre)



Source: CMA analysis of Department for Energy Security and Net Zero, Platts, Bloomberg and Bank of England data

⁷⁴ <https://www.gov.uk/government/publications/letter-to-the-cma-on-vigilance-for-unjustifiable-price-increases>

Appendix 2 – the refining process

The refining process breaks crude oil down into its various components, which are selectively reconfigured into new products.

Not all crude oil is the same

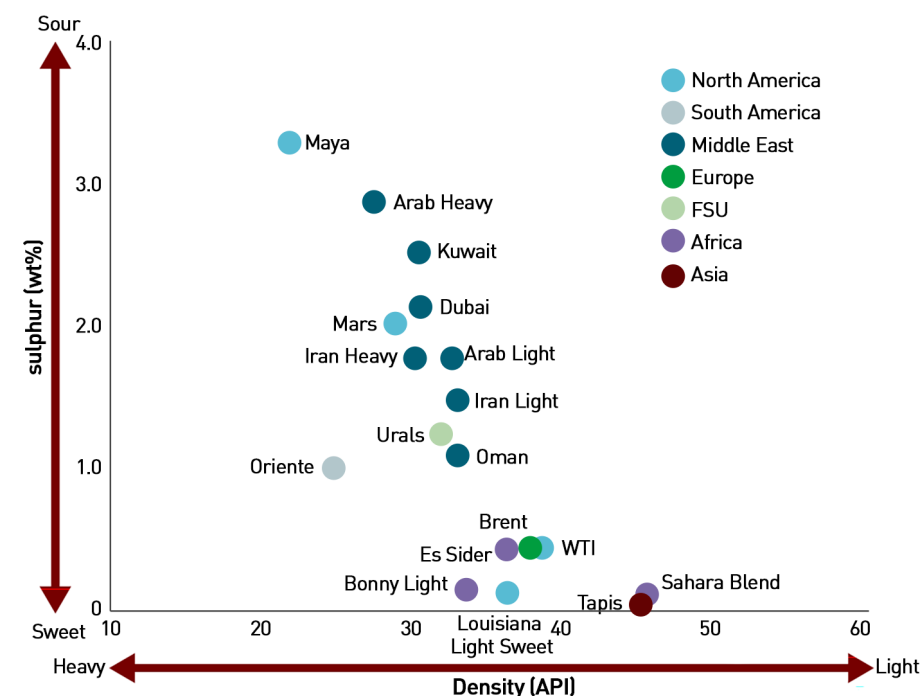
Crude oil grades are not uniform, and vary along two principal axes: density, measured by API gravity, and sulphur content:

- Density determines how easily a crude flows and how much of it distils into lighter, more valuable fractions. A light crude, with an API gravity above 35°, contains more naturally occurring naphtha and middle distillates than a heavy crude, which is more viscous and yields a larger residue fraction requiring further processing.
- Sulphur content determines refining complexity: sweet crude, with low sulphur levels, requires less desulphurisation and is less corrosive to refinery equipment, while sour crude demands additional processing units, higher operating costs and greater maintenance to manage the corrosive and toxic by-products of sulphur compounds, including hydrogen sulphide.

These two characteristics combine to give the market its shorthand: light sweet crudes, and heavy sour crudes. Light sweet crudes are generally the easier and cheaper to refine and therefore command a price premium, while heavy sour crudes trade at a discount, but are valuable feedstock for complex refineries equipped to handle them, since their lower purchase price can more than offset the additional processing cost. The majority of global reserves are sour crudes, but the main western pricing benchmarks, Brent and WTI are light sweet crudes. Heavy sour crudes include Russian Urals, Saudi Arab Heavy and Venezuelan Merey.



Crude oil quality



Source: U.S. Energy Information Administration, based on Energy Intelligence Group—International Crude Oil Market Handbook

The US shale revolution has transformed global crude markets. US oil production has grown from around 7% of global supply in 2009 to approximately 16% today, making the United States the world's largest oil producer ahead of Russia and Saudi Arabia⁷⁵. This growth has been dominated by light tight oil, lighter grades that yield a higher proportion of naphtha, gasoline and jet fuel precursors. US production has flooded the Atlantic Basin with light sweet crude, compressing the price premium that light grades have historically commanded over heavier alternatives. The share of heavy crude in global supply has remained broadly stable at around 10-15%, meaning the relative availability of the medium sour grades that European diesel-oriented refineries were configured to process has not grown proportionately with overall supply.

The result is that complex refineries configured to run heavy sour crudes are increasingly competing for a feedstock that has not grown proportionally, to the point where heavy sour benchmark grades have at times traded at a premium to light sweet equivalents on the US Gulf Coast in a reversal of the historic norm.

For European refiners who lost access to Russian Urals which is a medium sour grade that sat in the sweet spot for diesel-oriented refinery configurations, finding a direct replacement at comparable volume, quality and price has proved difficult.

However, a modern complex refinery (including older refineries that have been upgraded over time) with substantial conversion capacity can process a wide range of crude grades. The conversion units such as Fluid Catalytic Crackers ("FCCs") and associated hydrotreaters can handle significant variation in feedstock quality. In that sense, crude is not a hard technical constraint - the refinery will still operate with different crude grades within a reasonable range. However there may be an impact on the economics.

Petroleum refineries are complex and expensive industrial facilities. All refineries follow three basic steps: separation, conversion and treatment. The choice of conversion units is a major factor in the proportion of each of the refined products the refinery will be able to produce, although this

choice is an optimisation – it is not possible to focus on specific products to the exclusion of others. The output of a refinery is linked to the input and defined by chemistry – all the distillates will be present in some quantity but the choice of conversion technology allows for larger amounts of higher or middle distillates.

Refinery design and conversion unit choice

When an oil refinery is designed and built, the configuration of conversion units, that is the choice of secondary processing plant beyond the basic distillation column, determines what products the refinery will be capable of producing, in what proportions, and at what cost. These are capital decisions with thirty-year or longer payback periods. They cannot be meaningfully reversed without the kind of investment that would effectively constitute building a new refinery.

The central design choice is which conversion technology to install to upgrade the heavy fractions that emerge from the bottom of the distillation column. A fluid catalytic cracker ("FCC") uses a powdered catalyst at high temperature to crack heavy gas oil into lighter products, while a hydrocracker uses hydrogen at high pressure to achieve a similar result through different chemistry, with greater flexibility over the product slate and a stronger orientation toward middle distillates.

In practice, the UK's four remaining refineries are all configured around FCC units, originally installed in the 1970s and 1980s when gasoline dominated road fuel demand and maximising gasoline production was the primary commercial objective. Texaco, then owner of Pembroke, installed its FCC unit in the mid-1980s for precisely this reason.

Since then, demand has shifted significantly towards diesel and aviation fuel, driven by policy support for diesel in the late 1990s and sustained growth in global air travel. UK refineries now seek to optimise distillate output within the constraint that their conversion units inherently drive toward gasoline production. This configuration leaves UK refineries better placed to serve diesel and jet fuel markets than their equipment was originally designed to do, but less well placed than refineries built or substantially rebuilt in more recent decades with middle distillate optimisation as the primary objective.

However it is important to note that refinery design cannot deliver a fully bespoke product slate - crude oil distillation separates the chemicals physically present in the feedstock. Conversion units crack heavier molecules into lighter ones, but at every stage, the laws of chemistry determine what fractions are produced alongside the target products. A refinery optimised for diesel and jet kerosene will still produce significant amounts of gasoline. It cannot crack heavy gas oil into middle distillates without also generating a naphtha fraction.

The operator can adjust operating conditions and feedstock routing to shift the balance at the margin for example by running the FCC "harder" (increasing reactor temperatures, increasing the catalyst-to-oil ratio, or processing heavier feeds to maximise conversion into lighter, higher-value products like gasoline and propylene) or "softer" (lowering riser outlet temperature or reducing catalyst circulation to reduce conversion, usually to manage heat balance, minimise coke production, or deal with lower-quality feedstocks that cannot handle high severity), or by varying the cut points on the distillation column, but within limits that are set by the process chemistry, not by commercial preference. There is no configuration that produces only jet kerosene and no gasoline, just as there is no configuration that eliminates residual fuel oil entirely without additional coking capacity that makes a solid carbon-based fuel.

This is the structural origin of Europe's current fuel imbalance. UK and European refineries were configured and operated to maximise gasoline yield

⁷⁵ <https://www.energyinst.org/statistical-review>





prior to the decades of strong diesel demand growth from road freight, agriculture, construction and industry. As petrol demand has declined, driven by rising EV penetration, improved fuel efficiency, and shifting consumer behaviour, the gasoline fraction that FCC units inevitably produce has increasingly exceeded domestic demand.

Europe is simultaneously short of diesel and long of gasoline not because its refineries are poorly designed, but because the demand-side has shifted in ways that were not anticipated in the configuration decisions, and in any case the excess gasoline could not have been meaningfully avoided. The gasoline surplus is not a design flaw – it is an unavoidable consequence of the cracking chemistry. A refinery optimised for middle distillates will always produce gasoline as a by-product; as petrol demand has declined structurally across Europe, that by-product has increasingly had nowhere to go.

Crude oil selection operates within this framework but is less of a binding constraint than is sometimes assumed. UK refineries were originally built to handle a range of crude grades and have in practice processed both heavy imported crudes and lighter North Sea grades over their operating lives. These refineries were built before North Sea oil was first produced and were originally configured for heavy sour crudes, however they were easily able to accommodate the light sweet crude from the North Sea.

When the North Sea met all of Europe's fuel needs, all refineries refined North Sea crude. However, today the market relies on imports. UK refineries typically import crude for refining because it is logistically cheaper to take seaborne cargoes passing from west to east through the English Channel than it is to send North Sea crude east to west. The freight cost differential makes it more economic for North Sea oil to be refined in Europe (in the “ARA region” - Amsterdam-Rotterdam-Antwerp).

Purification

Raw crude oil contains water, salts and other contaminants which, if not removed, can form acids when heated, causing corrosion of downstream process equipment. Salts can also form deposits, causing plugging of heat exchangers or clogging trays in process towers. Salts in crude oil are mainly in the form of magnesium, calcium, and sodium chlorides, sodium chloride being the most abundant. These salts are either dissolved in emulsified water droplets in the crude oil, as a water-in-oil emulsion, or crystallised and suspended solids.

Refinery desalting is typically done in one or two stages, based on the characteristics and expected level of contamination after any pre-treatment carried out at the well head or pre-transportation stage. First the crude oil is heated to reduce its viscosity and improve water-oil separation efficiency. The heated crude is mixed with wash water and chemical demulsifiers. Proper mixing is critical to the salt removal and is achieved using mixing valves and static mixers.

The emulsion is broken by a high voltage electrostatic field within the gravity settler tank where small, dispersed salty water droplets coalesce into larger drops that settle to the bottom as brine. The brine containing extracted salts and other impurities is removed from the bottom of the tank for treatment. The desalted crude oil is then transferred to the atmospheric distillation column. The brine fluid produced is extremely corrosive and requires special materials of construction to avoid possible desalter shutdown and risk of plant shutdown. Austenitic stainless steel or Duplex materials are commonly specified.

Separation

Modern separation involves piping crude oil through hot furnaces. The re-

sulting liquids and vapours are discharged into distillation units. All refineries have atmospheric distillation units, but more complex refineries may have vacuum distillation units.

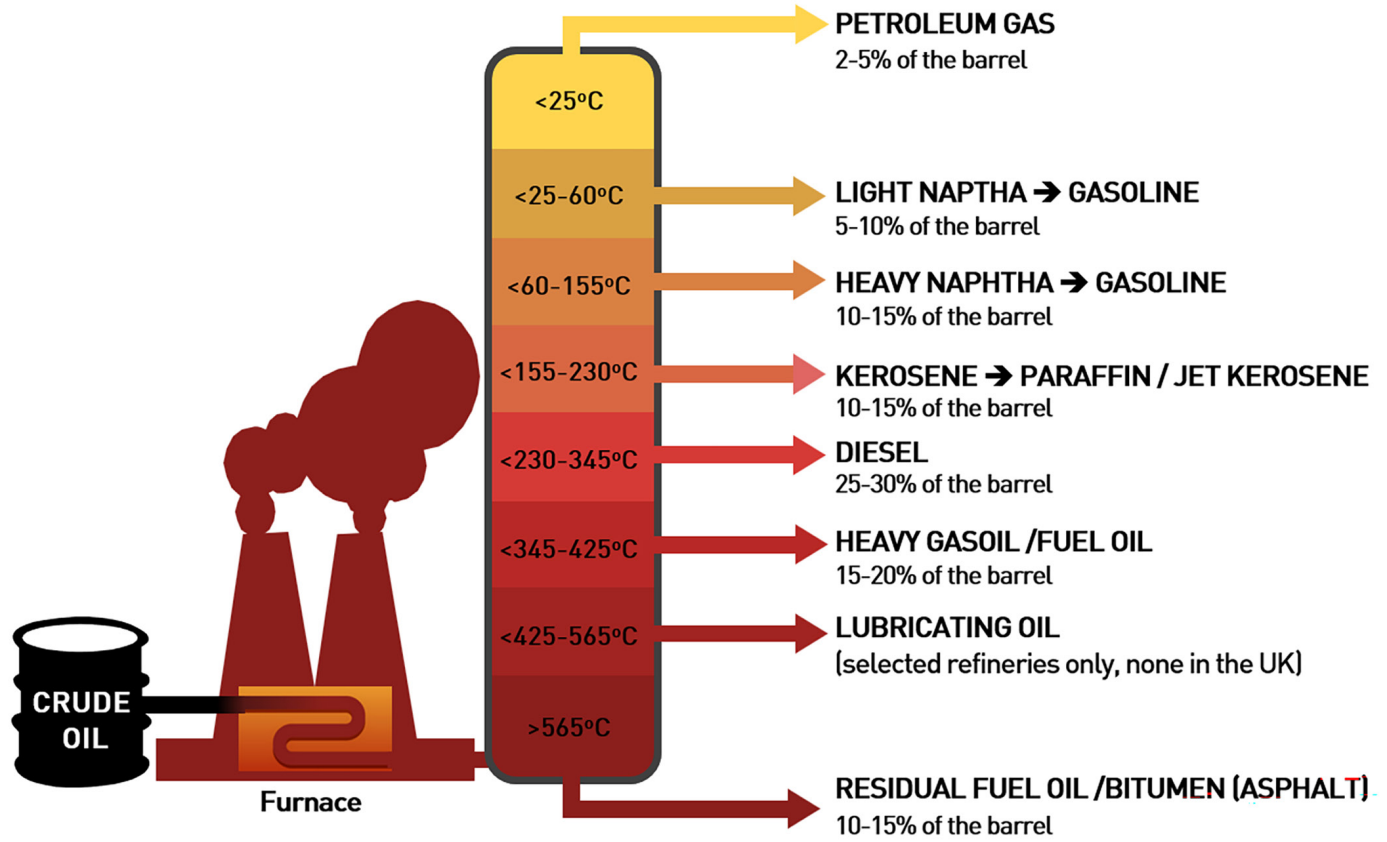
Atmospheric distillation

Every refinery starts with an atmospheric distillation unit (“ADU”), which is essentially a very large fractional distillation column. Crude oil is heated to around 350°C in a furnace, partially vaporising it before it enters the distillation column. Inside the column, a temperature gradient is maintained which is hotter at the bottom and cooler at the top. Lighter hydrocarbon fractions, with lower boiling points, rise higher up the column before condensing and are drawn off near the top, while heavier fractions condense lower down and are drawn off closer to the base. The heaviest material, which does not vaporise at all, falls to the bottom as atmospheric residue.

The lightest fractions – gases and liquified petroleum gas - come off at the top. Moving down the column, the fractions become progressively heavier: naphtha (the feedstock for petrol), kerosene (jet fuel), gas oil (diesel), and at the bottom, a heavy residue called atmospheric residue or “long residue.” Nothing is cracked or chemically altered at this stage, it is purely physical separation by boiling point.

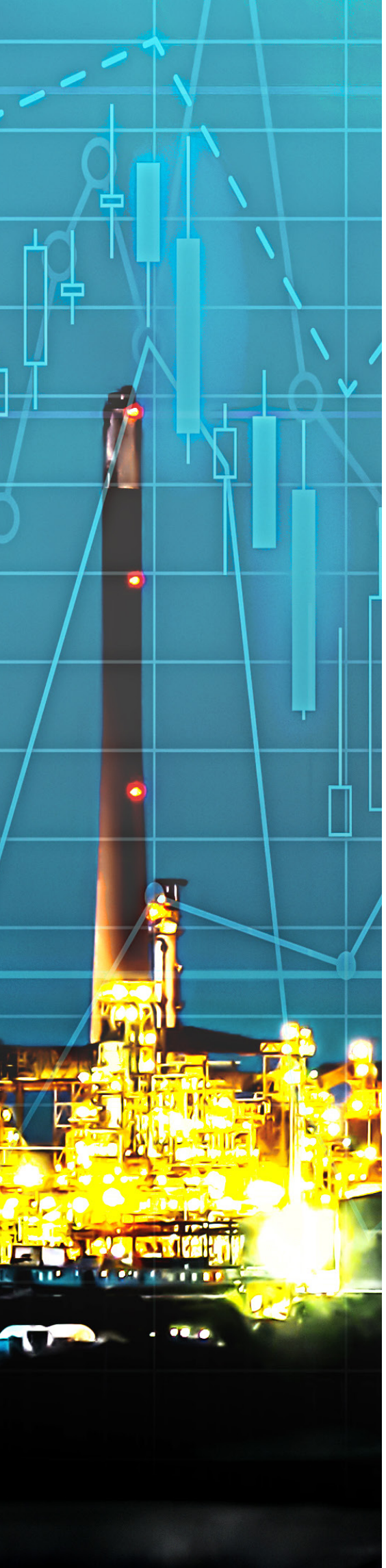
The yield profile from atmospheric distillation reflects the composition of whatever crude oil is being processed at the time. A light, sweet crude like North Sea Brent or UAE Murban contains a higher proportion of natural-

Fractional distillation of crude oil in refineries



Figures are approximate and do not include refinery fuel consumption and losses (~5-10% of the barrel)

Source: Watt-Logic



ly occurring naphtha and middle distillate fractions, while a heavy, sour crude like Russian Urals yields a larger residue fraction at the bottom.

Critically, this is not fixed by refinery design - operators routinely adjust their crude slate in response to price, availability and shipping logistics, accepting different distillation yield profiles and relying on downstream conversion units to add value to whatever the ADU produces. The crude going in determines the starting point but the configuration of the refinery determines how far it can go in converting that starting point into valuable products.

Vacuum distillation

The heavy atmospheric residue cannot be distilled further at atmospheric pressure without thermally decomposing. All the remaining UK refineries have vacuum distillation units, as do most European refineries. By applying a vacuum, the pressure is reduced enough so that the boiling point of the ADU bottoms is low enough that lighter products can vaporise without degrading the oil.

Vacuum distillation produces several types of gas oil which are slightly heavier than middle distillates such as jet fuel, kerosene, and diesel.

Conversion

A simple refinery that only distils crude will produce a large proportion of heavy, low-value products. The conversion units are what distinguish a complex “cracking” refinery from a simple one.

Visbreaking

Visbreaking (short for viscosity breaking) is a mild thermal cracking process applied to the heavy residual fuel oil that remains after vacuum distillation. Unlike the fluid catalytic cracker or delayed coker, which convert residue aggressively into lighter products, the visbreaker applies relatively gentle heat (around 450–500°C) for a short time, partially cracking the residue to reduce its viscosity and yield a small proportion of lighter products - naphtha and gas oil - alongside lower-viscosity fuel oil.

The primary objective is not maximum conversion but rather producing a residual fuel oil that meets viscosity specifications for sale without the addition of expensive cutter stocks (lighter products used to dilute thick residue to the required pumpability). By reducing viscosity through mild cracking, the visbreaker reduces the volume of cutter stock required, improving the overall economics of the residue disposition.

Visbreaking is a relatively simple and low-capital process compared and is typically found in refineries that have a significant fuel oil disposition, particularly those supplying marine bunker fuel or industrial fuel oil markets. It does not produce the large yield improvement of a coker or hydrocracker, but can meaningfully improve the economics of handling a heavy crude slate.

As European fuel oil demand has declined and environmental regulations on marine fuel sulphur content have tightened, the role of the visbreaker has become more complex, since the low-sulphur fuel oil required by the new regulations cannot be produced by visbreaking high-sulphur residue without prior desulphurisation.

Fluid catalytic cracking

There are three types of catalytic cracking: fixed-bed, moving-bed, and fluid-bed. Today, fluid-bed, otherwise known as fluid catalytic cracking

(“FCC”), is the most commonly used catalytic cracking method. FCC units contain a clay-like catalyst that provides convenient cracking sites for the hydrocarbon molecules. Because of the small size of these catalyst particles, it behaves like a fluid when it is pumped.

The FCC is the workhorse of conversion in most refineries, particularly those oriented toward gasoline production. It takes vacuum gas oil and cracks the large heavy hydrocarbon molecules into smaller, lighter ones using the catalyst at around 500°C. The key feature is the catalyst regeneration cycle: the powdered catalyst behaves like a fluid and circulates continuously between the reactor, where it contacts the hot feedstock and promotes cracking, and a regenerator, where the carbon deposits (coke) that accumulate on its surface are burned off, releasing heat that is recycled into the process. This continuous regeneration is what makes the process economically viable at scale.

The reaction products flow from the reactor to a main fractionator where they are separated into cracked naphtha, fuel oil and gases. After sulphur removal, the cracked naphtha becomes a high-octane component of blended gasoline. The offgas is separated into butanes, propane, propylene and lighter gases.

Hydrocracking

The hydrocracker performs a similar function to the FCC, converting heavy gas oils into lighter, more valuable products, but uses a fundamentally different mechanism. Rather than thermal cracking with a catalyst, the hydrocracker uses hydrogen under high pressure (typically 100–200 bar) and elevated temperature in the presence of a bifunctional catalyst containing both an acidic cracking component and a metal hydrogenation component. The hydrogen saturates the cracked fragments as they form, producing a cleaner, more stable product with very low sulphur content and a higher proportion of middle distillates - diesel and jet kerosene - rather than gasoline.

This makes the hydrocracker the preferred conversion unit for refineries oriented toward middle distillate production, as is common in the recently built export-oriented refineries in the Arabian Gulf. The products of hydrocracking, known as hydrowax, hydrocrackate and unconverted oil, are cleaner and require less subsequent treating than FCC products, but the process is more capital intensive and consumes significant quantities of hydrogen (made from methane and producing CO₂), making operating costs sensitive to the hydrogen/methane price.

The UK lost its only remaining hydrocracking capacity when Grange-mouth closed in April 2025. None of the four remaining UK refineries has a hydrocracker, which constrains their ability to maximise middle distillate yields from a given crude slate compared with some continental European competitors.

Coking

There are two types of coking units: delayed and continuous.

Delayed coking is a semi-continuous thermal cracking process used to upgrade the heaviest refinery residues - the vacuum residue that cannot be processed by an FCC or hydrocracker - into lighter products and solid petroleum coke. The feedstock is heated to around 500°C in a furnace and then fed at high pressure into large drums where the thermal cracking reaction completes. The lighter products - gas, naphtha and gas oil - are recovered overhead, while the coke accumulates on the drum walls as a solid and removed using hydraulic cutters. The drums are operated in pairs, alternating between filling and cutting cycles.

Petroleum coke has several end uses depending on its quality. Fuel-grade



coke is a low-value by-product used as an industrial fuel. Anode-grade and specialty graphite coke commands a significant premium and is a critical input for lithium-ion battery anodes and electric arc furnaces used in steel recycling. Humber is the only UK refinery with coking units and the only European producer of specialty graphite and anode-grade petroleum coke.

Continuous coking requires two separate units. In the first unit, steam is pumped through the base of the reactor, fluidising a bed of fine coke particles. The hot fluidised particles mix with the hydrocarbon feed, causing the hydrocarbons to decompose, creating lighter hydrocarbons and coke as a by-product. The cracked products leave through the top of the reactor and are sent to a fractionator. Excess coke from the reaction becomes mixed with the fluidised coke. To prevent an accumulation of material, the coke is continually circulated to a second unit, where it is separated by particle size into fractions. The smaller particle fraction is reheated and sent back to the reactor unit, while the larger particle fraction is removed from the unit to maintain steady state operation.

Combination

Cracking is not the only form of crude oil conversion - other refinery processes rearrange molecules rather than splitting them to improve quality and add value. Combination processes generally aim to increase the value of lower-value streams, which they primarily do by creating additives that result in higher octane gasoline.

Higher octane is needed to prevent autoignition of gasoline (knocking) in an engine and to meet minimum octane requirements for modern engines. Engine knock is a damaging phenomenon occurring when gasoline ignites prematurely in a cylinder, before the spark plug fires, leading to inefficient combustion, reduced power output and potential engine damage. Higher octane ratings prevent this premature ignition, improving combustion efficiency and enabling the use of higher compression ratios, a key factor in the improved fuel economy and performance of modern engines.

Alkylation

Alkylation is a secondary refinery process that many refineries have because it adds high octane hydrocarbons to motor and aviation gasoline.

The alkylation unit combines light olefins, primarily butylene and propylene from the FCC offgas, with isobutane to produce alkylate, a premium high-octane, low-vapour-pressure gasoline blending component. The reaction uses either hydrofluoric acid (HF) or sulphuric acid as a catalyst.

Regardless of the acid-catalyst used, the alkylation process reacts with a hydrocarbon that has double bonds, such as propylene or butylene, with isobutane. The resulting product is usually a seven- or eight-branched carbon molecule. Unlike cracking, which increases total volume of products versus the feedstock by reducing density, alkylation takes two low-density feedstocks and produces a higher density product. The feed volume is reduced by about 15% while maintaining the same weight.

HF alkylation is the more common configuration in UK refineries, whereas sulphuric acid is more common in the UK. Across Europe the picture is more mixed. Alkylation units, both HF and sulphuric acid, are present at most complex European refineries but are not universal.

Catalytic reforming

Reforming is an oil refining operation that produces reformate, a high-octane gasoline blending component- reformate is one of several blending components in finished gasoline.

The reforming process uses heavy naphtha, which is the second lightest liquid stream from an atmospheric distillation column, and passes it through a catalytic reformer to produce reformate which is blended into gasoline. The reformer uses a platinum-based catalyst to rearrange the molecular structure of naphtha, converting low-octane paraffins into high-octane aromatics - principally benzene, toluene and xylene - and producing hydrogen as a by-product. That hydrogen is recovered and recycled for use in the hydrotreaters. Benzene is extracted for use in chemicals and because it is not allowed in gasoline at more than 1% by specification.

Other components added to gasoline include alkylate from the alkylation unit, naphtha and straight run gasoline from the atmospheric distillation unit, cracked gasoline from the fluid catalytic cracker and coker, and hydrocrackate, which is gasoline from the hydrocracker. The amount of each component in finished gasoline depends on the particular specifications of the gasoline blend. Important considerations in gasoline blending include octane, distillation, and volatility to meet summer and winter grade gasoline specifications.

Because reformate contains significant amounts of benzene, toluene, and xylene, it also is an important source of feedstock for the petrochemical industry. One of the byproducts of reforming is hydrogen, which can itself be used in other refining processes or sold for other industrial use.

Polymerisation

Polymerisation is a process in which a substance of low molecular weight is transformed into one of the same composition but higher molecular weight, maintaining the atomic arrangement present in the basic molecule. It has also been described as the successive addition of one molecule to another by means of a functional group, such as that present in an aliphatic olefin. In refining, polymerisation is a process by which olefin gases are converted to liquid condensation products that may be suitable for gasoline.

Polymerisation may be accomplished either thermally or through the use of a catalyst at lower temperatures. Thermal polymerisation is not considered to be as effective as catalytic polymerisation but has the advantage that it can be used to polymerise saturated materials that cannot be induced to react by catalysts.

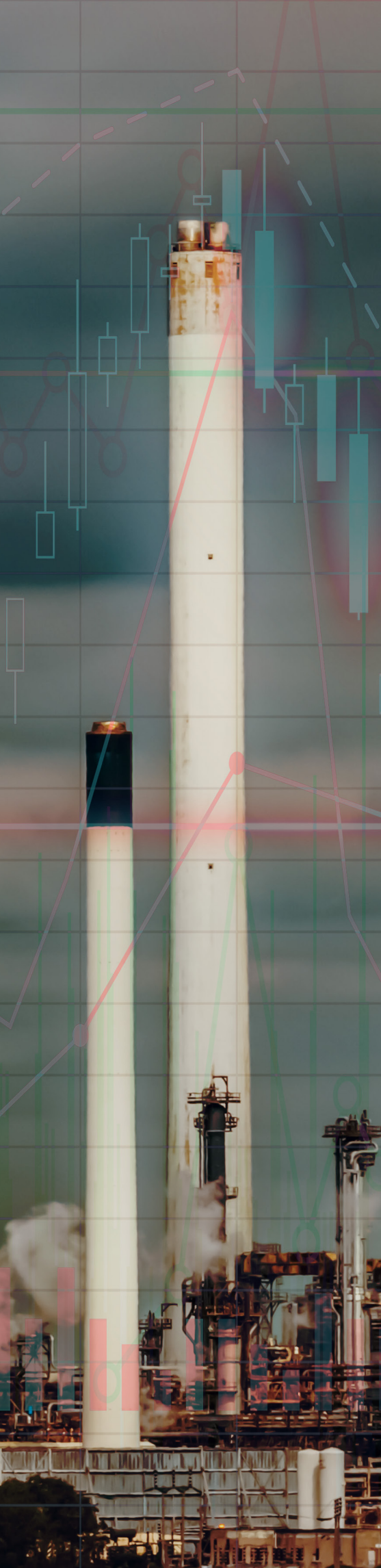
Catalytic polymerisation combines smaller olefin molecules, typically propylene and butylene from the FCC offgas, to produce higher olefins with high-octane numbers for the gasoline pool. It is a simpler process than alkylation and does not require the handling of hazardous acid catalysts, but produces a lower-quality product.

The polymerisation process was used extensively in the 1930s and 1940s, but it was replaced to a large extent by alkylation after World War II. It has gained favour after phasing out the addition of tetraethyl lead to gasoline, and the demand for unleaded gasoline has increased.

Isomerisation

Isomerisation is a chemical rearrangement process that converts straight-chain hydrocarbons into branched-chain isomers. While these molecules share the same chemical formula, their altered structure creates enhanced properties, particularly a higher-octane rating, which is critical for gasoline performance.

The primary purpose of isomerisation in refining is to enhance the octane number of light naphtha. Converting straight-chain paraffins (normal paraffins) into their branched isomers (isoparaffins) increases the gasoline's resistance to engine knock. The isomerisation process also produces



isobutane, an important feedstock for the alkylation unit. The process operates at relatively mild conditions compared with catalytic reforming.

Treatment

Refineries include further treating processes to remove impurities from petroleum product streams to meet environmental regulations and product quality specifications. The principal impurities targeted are sulphur, nitrogen, heavy metals and oxygen compounds, all of which cause problems either in the final product by contributing to harmful emissions when burned, or in the refinery itself, by poisoning catalysts in downstream units.

Catalytic hydrotreating and hydroprocessing

Catalytic hydrotreating is the most widely used treating process in modern refineries. The product stream is combined with hydrogen and passed over a catalyst - typically cobalt-molybdenum or nickel-molybdenum on an alumina support - at elevated temperature and pressure. The hydrogen reacts with sulphur compounds to form hydrogen sulphide, with nitrogen compounds to form ammonia, and with oxygen compounds to form water, all of which are then removed from the treated product stream. The result is a cleaner product with lower sulphur content, meeting the stringent specifications required for ultra-low sulphur diesel and ultra-low sulphur petrol under European regulations.

Hydrotreating also performs a secondary upgrading function in converting olefins and diolefins - unstable, reactive molecules produced by cracking - into stable paraffins. This reduces gum formation in fuels, which would otherwise cause deposits in fuel systems and storage tanks, and improves the storage stability and combustion characteristics of the finished product.

Hydroprocessing is a broader term that encompasses both hydrotreating and hydrocracking in the same unit, operating at higher severity. At hydroprocessing conditions, heavier feedstocks are not only cleaned but partially cracked into lighter, more valuable products, combining the treating and conversion functions in a single step. This makes hydroprocessing units particularly valuable for upgrading heavy, high-sulphur gas oils that would not otherwise meet product specifications or that are too heavy for direct blending into finished fuels.

The hydrogen consumed by hydrotreating and hydroprocessing units is a significant operating cost. It is supplied from one of three sources: hydrogen produced as a by-product of catalytic reforming, a dedicated hydrogen plant using steam methane reforming (where methane is converted into hydrogen and carbon dioxide), or a combination of both. The management of hydrogen across the refinery, balancing production, consumption and purity, is an important aspect of refinery optimisation, and the availability of hydrogen constrains how aggressively hydrotreating units can operate.

Nelson Complexity Index

The Nelson Complexity Index ("NCI") is a comparative metric system that rates oil refineries based on their ability to process crude oil into refined, higher-value products. The NCI was developed by Wilbur Nelson in 1960, to compare refinery sophistication and construction costs, providing a standardised measure across the industry. It measures the complexity and cost of each major type of refinery equipment and describes a refinery's secondary conversion capacity that is its ability to upgrade the heavy fractions that emerge from primary distillation, against its crude distillation capacity.

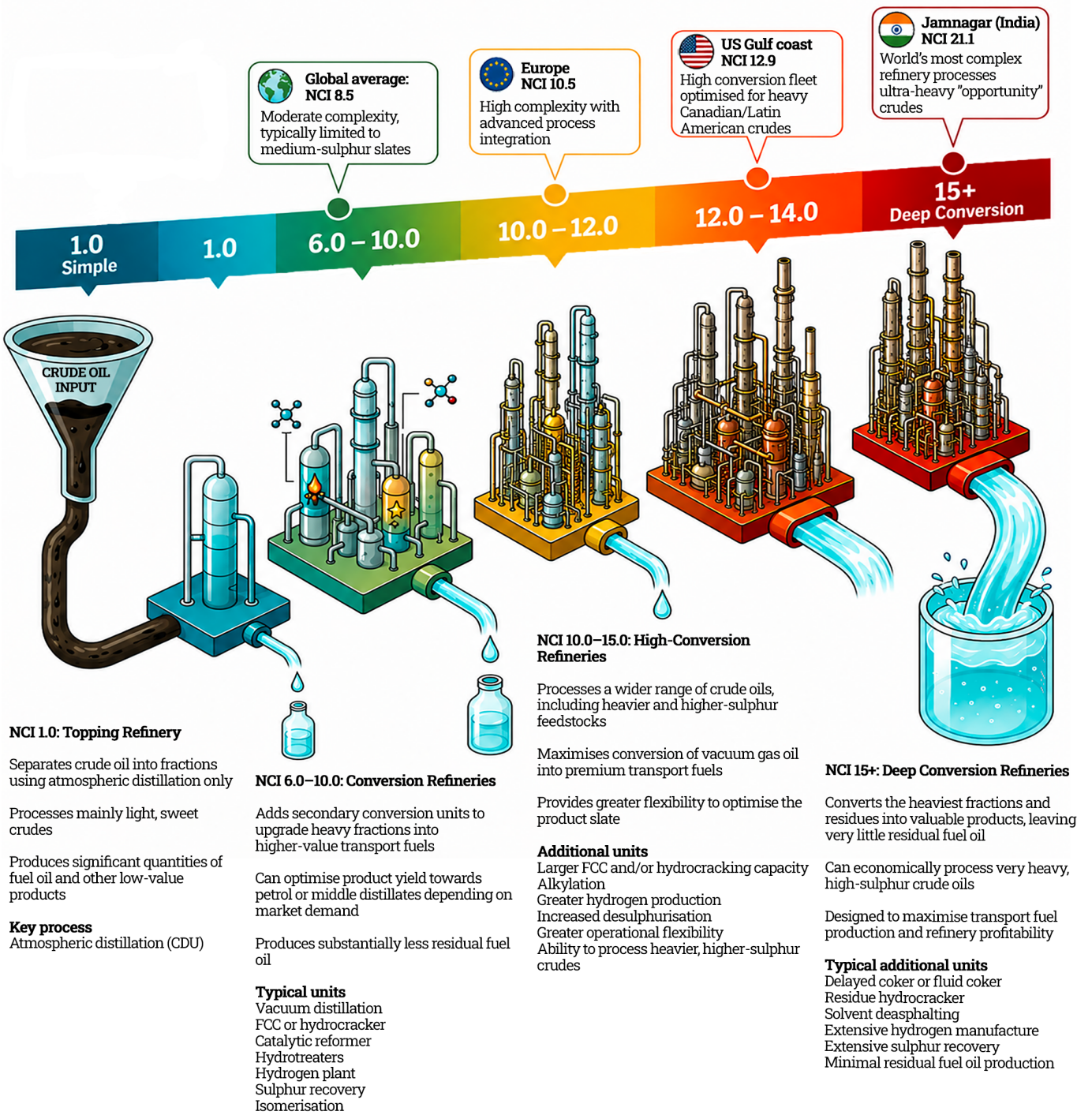
It uses a scale of 1 to 20 or even higher, for example the new Jamnagar re-

finery has an NCI of 21.1, with higher scores indicating more complex and capable refineries. A higher complexity score implies a refinery can produce a larger variety of high-demand products, making it more profitable and versatile.

A simple hydroskimming refinery that does little more than distil crude oil scores around 2 to 3 on the index while a highly complex coking refinery with hydrocracking, fluid catalytic cracking and multiple treating units can score above 12. A higher NCI generally indicates both higher capital investment and greater ability to extract value from crude feedstock, producing more high-value transport fuels and fewer low-value residual products.

Nelson index is calculated applying established complexity indexes in the

Nelson Complexity Index



Source: Watt-Logic

table below:

Complexity Index for oil refining processes

Refining process	Index
Atmospheric distillation	1.0
Vacuum distillation	2.0
Delayed coking	6.0
Catalytic cracking	6.0
Catalytic reforming	5.0
Hydrocracking	6.0
Alkylation	10.0
Aromatics / Isomerisation	15.0
Lubricating production	10.0
Oxygenates production	10.0

Source: Wilbur L. Nelson, *Oil & Gas Journal* (1998 values)

Key refinery operating challenges

A refinery is essentially a continuous process plant that is designed to run around the clock - stopping and starting is expensive, operationally and technically demanding whilst introducing additional safety hazards. Maintaining a steady supply of crude oil is therefore the first operational priority. For UK refineries, crude arrives almost exclusively by sea. Tankers discharge at dedicated marine terminals, from which crude is pumped via pipeline to refinery storage tanks, providing a buffer of typically two to four weeks of supply. The size of that buffer is commercially significant: buying crude earlier to build stocks costs money, while running stocks down to minimise working capital increases vulnerability to any disruption in shipping.

In practice, UK refineries try to match their crude deliveries closely to their processing rates, which makes them sensitive to delays caused by weather, port congestion, tanker availability, or - as the current crisis in the Strait of Hormuz has demonstrated - disruption to shipping routes.

Once crude arrives, the refinery operates as a series of linked process units, each with its own throughput rate and operating parameters. The crude distillation unit sets the pace for the downstream processes - if it runs at 80% of its nameplate capacity, every subsequent unit has correspondingly less feedstock to work with. Refineries can and do vary their throughput in response to market conditions, maintenance requirements, or crude availability, but there are limits. Running significantly below design throughput is uneconomic because many costs including energy, staffing and maintenance are largely fixed regardless of how much crude is being processed. Running above design throughput risks equipment stress and product quality issues and is limited by various regulations or safety case requirements.

Operational flexibility within a given configuration is real but limited. Operators can adjust cut points on the distillation column, vary the severity of the FCC operation, and change blending recipes for finished products, all of which allow some shift in the product slate in response to market prices. In practice this flexibility operates within relatively narrow bands - a refinery cannot switch from producing primarily diesel to primarily jet fuel overnight, and it cannot eliminate its gasoline output regardless of market conditions.

A refinery is configured around expected ranges of crude quality, so if a cargo arrives that is significantly outside those parameters for example higher sulphur than expected, different density, or contamination with water or other products, it creates problems that cascade through the plant. Hydrotreaters sized for a given sulphur load may be unable to process a higher-sulphur crude to the required ULSD specification without reducing throughput, while an FCC optimised for a particular feedstock viscosity and density will produce a different and potentially less valuable product mix if the crude slate changes significantly. In extreme cases, off-spec crude can cause equipment fouling or corrosion that requires unplanned maintenance.

Supply disruptions cause a different category of problem. If crude deliveries are delayed or interrupted, the refinery must draw down its storage buffer. A two-to-four week buffer sounds comfortable, but if the disruption extends beyond that, the refinery faces a choice between reducing throughput, which is costly but manageable, or shutting down units entirely, which is significantly more disruptive and expensive. Restarting a cold unit is not straightforward: it takes time, consumes energy, and generates off-spec product during the warm-up period that cannot be sold.



The operational challenges do not end when refined products leave the processing units. Finished fuels must be moved out of the refinery into the distribution system promptly as storage tanks on site have limited capacity, and if the tanks fill up because product cannot be moved, the refinery would have to reduce throughput or pause operations. This is the mirror image of the crude supply problem - just as a refinery requires a steady flow of crude coming in, it needs a steady flow of finished products out.

UK refineries distribute their products through three main routes: the national pipeline network, coastal tankers, and road tankers. The pipeline network which connects the refineries to regional distribution terminals and airports is the most efficient route for bulk product, but capacity is fixed and shared between multiple users. Coastal tankers provide flexibility for moving product between ports but are subject to weather and vessel availability. Road tankers are the most flexible but also the most expensive and capacity-constrained per unit volume. If any of these routes is disrupted either by bad weather, industrial action, tanker shortages, or pipeline maintenance, product can back up at the refinery and supply to retail forecourts and airports tightens.

The UK's operational vulnerabilities are not categorically different from those of continental European refiners, but they are more acute in several respects.

Most European countries retain more domestic refining capacity relative to their demand than the UK does following the 2025 closures, giving them a larger margin before product import dependence becomes critical. Several continental refineries, particularly in the ARA hub, have better pipeline connectivity to inland demand centres and more diverse crude supply routes than UK coastal refineries, although the UK does benefit from diverse crude supplies as it is able to access cargoes bound for ARA via the English Channel. Continental governments have also been more proactive – or interventionist, in response to greater union pressure, particularly in countries such as France and Italy.

France maintains a minimum number of active refineries under a national strategic resilience policy, while Germany has co-funded upgrades at its refineries to ensure some domestic processing remains viable. The UK has no equivalent policy framework.

Asian refineries, particularly in China, South Korea and Japan, are generally newer, larger, and more complex than their European counterparts, with better integration between refining and petrochemicals and more modern process control systems. However, Asian markets are also far more exposed to Hormuz disruption, importing more than 60% of their total crude requirements from Middle Eastern sources.

Middle Eastern refineries present a different picture again. Export-oriented by design, they are built to run at high utilisation rates and move large volumes of product to international markets. Unlike facilities serving domestic markets, export-oriented installations cannot easily accumulate inventory during distribution disruptions, forcing immediate throughput reductions when shipping access is constrained. The current conflict has therefore imposed disproportionate operational stress on precisely the refineries that the global market was most relying on to compensate for tighter supply elsewhere.

For UK refineries, the net position is one of mature assets, limited domestic alternatives if they underperform, constrained distribution infrastructure, and a policy environment that has not historically treated their operational continuity as a strategic priority. The Lindsey closure illustrated how financial losses, maintenance costs and financing difficulties can combine to bring a refinery down relatively quickly – and that once a refinery closes, the infrastructure, skills and supply chain relationships it supported are typically lost.



Appendix 3 – UK refineries sector

Fawley (ExxonMobil)

Fawley (in Hampshire) is the UK’s largest refinery and one of the most complex in Europe. The original refinery was built in 1921 by Atlantic Gulf and West Indies Company. It was acquired by Esso (later re-named Exxon) in 1925, although it was substantially rebuilt and extended in 1951. It has a crude processing capacity of 270,000 bpd, which is just under 30% of the UK’s total refining capacity, covers 3,250 acres and employs over 2,500 people including contractors.

The refinery operates two crude distillation units with associated vacuum distillation units – a third crude distillation unit and its associated vacuum distillation unit is currently mothballed, with emission limits to be agreed before either returns to service. The primary conversion unit is a fluid catalytic cracker, which upgrades heavy vacuum gas oil into motor gasoline components, gas oil and LPG⁷⁶.

Two catalytic reformer units upgrade naphtha to produce high-octane reformate for the motor gasoline pool: a cyclic reformer, and a semi-regenerative reformer. A wax isomeriser and light ends unit process additional intermediate streams, while an isomerisation unit upgrades light naphtha to increase its octane value. Treating and desulphurisation is handled by a suite of eight hydrotreating units, reflecting the breadth of product streams requiring sulphur removal. Sulphur is recovered through two SRU trains with a tail gas treatment unit processing sour gases from across the site.

Steam and power are generated by two 400 MWth boilers (combined capacity limited to below 500 MWth by software interlock), a 196 MWth gas turbine combined heat and power unit and a 451 MWth gas turbine cogeneration unit. Two bitumen plants have been decommissioned.

In 2019 three new units were authorised, comprising the FAST project: a new steam methane reforming hydrogen plant (130 MWth, with a pressure swing adsorption unit), a new high pressure diesel hydrofiner (12 MWth), adding approximately 37,000 barrels per day of ultra-low sulphur diesel production capacity and increasing Fawley’s diesel output by approximately 40%, and a replacement low-sulphur jet hydrofining reactor. These units were commissioned in 2025. The project shifts the site’s product balance materially toward middle distillates and is estimated to reduce UK diesel import requirements by approximately a quarter.

The refinery installation boundary also encompasses the ExxonMobil Chemical Limited petrochemical plant which produces halobutyl rubber - used in the majority of European vehicle tyres - alongside other chemical products from refinery feedstreams. The site also hosts the largest refrigerated

erated LPG storage facility in Northern Europe.

ExxonMobil cancelled its proposed hydrogen production and carbon capture project at Fawley through the Solent Cluster⁷⁷, due to lack of government support.

Fawley sits within ExxonMobil’s global downstream portfolio under the Esso Petroleum Company Ltd (“EPC”) subsidiary. ExxonMobil does not publish refinery-level financial accounts for Fawley specifically, but EPC Ltd’s own strategic report confirms its principal activity is “the refining, distribution and marketing of petroleum products in the United Kingdom,” making its statutory accounts a reasonably clean UK-downstream-only proxy. EPC Ltd’s turnover fell to £10,594 million in 2024 (2023: £11,207 million), which the company attributes to a 7% fall in market prices against broadly stable volumes⁷⁸. The company swung to an operating loss of £41 million (2023: profit of £253 million) after expensing rather than capitalising turnaround costs. The loss for the year widened to £63 million after an £87 million impairment against EPC’s investment in its Indonesian subsidiary, PT Federal Karyatama, unrelated to UK refining.

No dividend was paid to the parent in 2024, against £500 million distributed in 2023. Recent investment has focused on improving product quality and margins rather than maintaining legacy capacity: £208 million was added to assets under construction in 2024, with £426 million transferred into plant and machinery, consistent with the low-sulphur diesel facility reaching completion.

In particular, ExxonMobil commissioned the £800 million Fawley Hydrofiner, which upgrades lower-value distillates into higher-value ultra-low sulphur diesel for the UK market, as part of a wider programme of high-return downstream investments. This new low-sulphur diesel unit will produce an additional 37,000 bpd of ultra-low sulphur diesel, increasing Fawley’s diesel output by 40%⁷⁹. This formed part of the wider US\$1.5 billion Fawley Strategy (FAST) project, described as the “largest upgrade to a British refinery in decades”⁸⁰ which also included a new hydrogen production plant, significant modifications to existing refining units, including expansion of the residfiner, together with extensive supporting infrastructure, utilities and refinery integration works⁸¹.

Looking back to what was considered the “golden era” of UK refining 2003-2008, Fawley’s 2024’s weak result should be read against a much stronger

⁷⁷ https://corporate.exxonmobil.com/news/news-releases/2021/1208_exxonmobil_sgn_green-investment-sign-mou-for-southampton-hydrogen-hub

⁷⁸ <https://find-and-update.company-information.service.gov.uk/company/00026538/filing-history/MzQ4MTQwNjcwNGFkaXF6a2N4/document?format=pdf&download=0>

⁷⁹ <https://corporate.exxonmobil.com/locations/united-kingdom/fawley/fawley-hydrogen-facility-investment#Fawleyshydrogenplant>

⁸⁰ <https://zenithstructural.com/case-studies/exxonmobil-fawley-new-reactor-refurbishment-project/>

⁸¹ <https://investor.exxonmobil.com/company-information/press-releases/detail/198/exxonmobil-to-expand-ultra-low-sulfur-diesel-production-at>

⁷⁶ https://assets.publishing.service.gov.uk/media/5c7d56daed915d4067f2b333/Variation_and_consolidation_notice.pdf





pre-2008 baseline. In 2007, EPC Ltd reported turnover of £7,010.6 million, operating profit of £383.8 million (an operating margin of 5.5%, itself attributed by the company to “higher refining margins”), and profit for the year of £307.7 million⁸². Return on net assets (using net assets inclusive of the pension position) of £1,403.2 million in 2007, on a consistent basis with the £3,003 million reported in 2024 was 21.9% in 2007, against -2.1% in 2024, when the company made an outright loss.

Because 2024 was a loss-making year, a fairer like-for-like comparison uses EPC’s most recent profitable year, 2023, when the operating margin was 2.3% and return on net assets was 8.5%, both still a fraction of 2007’s 5.5% and 21.9%. This confirms 2024 wasn’t simply a one-year dip but a sustained structural decline, consistent with the pattern across the sector.

Clearly, the economic muscle of ExxonMobil provides Fawley with significant financial security, but even on a standalone basis, the refinery is well configured for its local market. However, it is not immune from the headwinds facing the UK refinery sector and remains vulnerable to high electricity costs and a punitive carbon taxing regime.

Pembroke (Valero)

The Pembroke Refinery, in Pembrokeshire, Wales came on stream in 1964 and was initially owned by the Regent Oil Company, a large domestic marketer of Trinidadian crudes. Regent was fully acquired by Texaco in 1956, and was in turn acquired by Chevron in 2000.

Valero Energy Corporation bought the refinery from Chevron in 2011. Despite occupying a smaller site than Fawley, Pembroke has a similar throughput with a total capacity of 270,000 bpd. This represents just under 25% of UK refinery capacity.

The refinery is configured as a coastal complex refinery processing primarily light sweet crude oils. The site operates a single atmospheric crude distillation unit with associated vacuum distillation. The principal conversion unit is a fluid catalytic cracker, commissioned in 1982, which upgrades heavy residues into motor gasoline components, gas oil and LPG. A catalytic reformer upgrades naphtha to produce high-octane reformate for the motor gasoline pool^{83,84}.

Three hydrotreating units desulphurise intermediate streams and finished products to meet ULSP and ULSD specifications. Between 2006 and 2014 the refinery underwent a series of operational upgrades, most notably the implementation of an advanced ULSD optimisation system in 2006 covering the crude distillation, vacuum distillation, hydrotreating and FCC units, which delivered a 10% increase in middle distillate production through co-ordinated process unit optimisation⁸⁵.

An HF alkylation unit converts light olefins from the FCC into high-octane alkylate for gasoline blending. Product sweetening is handled by Merox treaters for kerosene and other streams. Sulphur is recovered through a dedicated SRU with sour water stripping. A 49.9 MWe cogeneration unit, commissioned in 2021, provides electricity and supplementary steam to the site from a gas turbine with heat recovery steam generator, reducing

⁸² <https://find-and-update.company-information.service.gov.uk/company/00026538/filing-history/MjAxMDU4Mjc2MmFkaXF6a2N4/document?format=pdf&download=0>

⁸³ <https://naturalresources.wales/media/685191/valero-refinery-bref-review-draft-decision-document.pdf>

⁸⁴ <https://naturalresources.wales/permits-and-permissions/permit-applications-consultations-and-decisions/current-consultations-environmental-permit-draft-decisions/pembroke-refinery-valero-energy-ltd/>

⁸⁵ https://www.aspentech.com/-/media/aspentech/home/resources/events-and-workshops/pdfs/fy18/q4/acowug-2018/2018-acowug-an-rigden-valero-pembroke-gdot.pdf?sc_lang=en

dependency on grid power and site boilers.

Products are distributed approximately 75% by sea a consequence of Pembroke’s coastal location and deep-water port infrastructure, with the remainder by pipeline to the Midlands and Manchester and by road tanker (around 2%). The refinery’s crude terminal is capable of handling tankers of 275,000 tonnes deadweight. Approximately 44% of output is gasoline and 40% distillates, consistent with the FCC-dominated configuration processing light sweet crudes.

Supporting over 1,000 jobs, Pembroke Refinery is one of the largest employers in West Wales contributing around £75 million per year to the local economy, and accounting for approximately 15% of Welsh export GDP⁸⁶.

Valero Energy Ltd, the UK subsidiary through which Valero Energy Corporation operates the Pembroke Refinery alongside UK marketing activities under the Texaco and Valero brands, reported turnover of £10.7 billion for the year ended 31 December 2025 (2024: £10.3 billion), with profit after taxation of £304.6 million (2024: £253.3 million). The recovery reflects a return to fuller-year running as 2024’s results were depressed by a planned turnaround in Q3 2024 that cut refinery utilisation to 67.9% from 73.9% for 2024 as a whole. With no comparable turnaround in 2025, operating profit almost doubled to £369.8 million (2024: £197.5 million), and gross margin rose to 7.8% of turnover (2024: 5.9%)⁸⁷.

Net assets rose to £3,249.5 million (2024: £3,179.1 million) despite a £234.2 million dividend paid to the parent during the year, a materially lower payout than the £438.0 million distributed in 2024. Cash at bank rose to £1,198.1 million (2024: £874.0 million), underlining continued strong cash generation. Headcount fell modestly to 618 (2024: 635). The stock write-down to net realisable value increased sharply to £71.8 million (2024: £11.8 million), which is consistent with softer refined product prices at the end of 2025, a detail that sits somewhat at odds with the otherwise stronger full-year result. This is unlikely to represent the start of a deteriorating trend as refining margins have moved sharply higher since in the wake of the Iran war.

It might be tempting to look at this strong set of results and assume that the UK refinery sector is in good shape. That would be a mistake. While the last few years have shown some improvement, they are significantly worse than in the period before the 2008 financial crash which coincided with the start of a prolonged deterioration in UK refinery competitiveness as energy costs rose sharply.

Valero’s return on net assets - the cleanest available comparator given the differences in entity scope between then and now - stood at 15.4% in 2007 against just 9.4% in 2025, a decline of well over a third, despite 2025 being a comparatively strong year versus the recent past⁸⁸. Operating margins tell the same story - down from 3.79% in 2007 to 3.45% in 2025. Adjusted for inflation, 2007’s £206.4 million profit is worth in the region of £340–360 million in today’s money, comfortably above the £304.6 million actually reported for 2025.

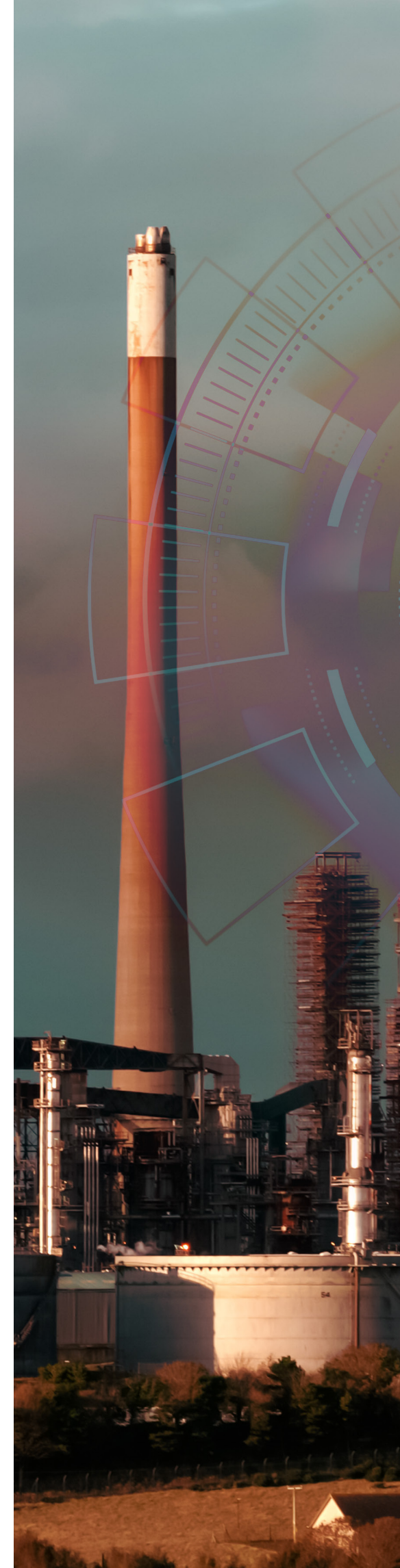
Valero’s North Atlantic region, comprising Pembroke and the Jean Gaulin refinery in Canada, reported a refining margin of \$1,014 million in Q2 2026 against \$476 million in Q2 2025, with throughput of 506,000 barrels per day and a refining margin of \$22.02 per barrel, reflecting the strong middle distillate crack environment and the absence of planned maintenance downtime that affected 2025 comparatives⁸⁹.

⁸⁶ <https://committees.parliament.uk/writtenevidence/152004/html/>

⁸⁷ <https://find-and-update.company-information.service.gov.uk/company/08566216/filing-history/MzUzNzg1MjQ4MWFkaXF6a2N4/document?format=pdf&download=0>

⁸⁸ <https://find-and-update.company-information.service.gov.uk/company/00145197/filing-history/MjAxNzEwOTM2MGFkaXF6a2N4/document?format=pdf&download=0>

⁸⁹ <https://investorvalero.com/news/news-details/2026/Valero-Energy-Reports-Second-Quarter-2026-Results/default.aspx>



Humber (Philips 66)

The Humber Refinery is located in North Lincolnshire, close to the now closed Prax Group's Lindsey refinery whose assets it purchased in 2026⁹⁰ (Phillips 66 does not intend to re-start the Lindsey refinery – instead it plans to integrate key assets such as storage facilities into operations at its Humber refinery). The Humber refinery was first planned in 1964 and was expected to cost £15 million, and to be operational by late 1966. It actually opened in 1969 after delays caused by severe weather and industrial action, and cost £50 million (approximately £750 million in today's money).

In 1969 the capacity was 80,000 bpd, targeting the domestic petroleum coke market that was then almost entirely met by imports. In the mid-1970s a £45 million expansion increased capacity to 130,000 bpd, partly fed by North Sea crude including the first delivery from Britoil's Thistle field in 1978. In the 1990s a £500 million by Conoco brought the refinery to its current scale and configuration. Humber has attracted major capital commitment from every owner across six decades.

Humber is the most technically sophisticated UK refinery, with a unique coking capability that enables it to process heavy sour crudes that other UK refineries cannot economically handle, and a product diversification into specialty coke, sustainable aviation fuels and petrochemicals that insulates it partially from conventional fuel demand decline.

The current refinery complex is built around two crude topping units feeding three vacuum distillation units. The primary conversion unit is a fluid catalytic cracking unit ("FCCU"), which processes vacuum gas oil and heavy residues into lighter products including motor gasoline, gas oil and LPG⁹¹. The FCCU is unique among UK refineries in being permitted for post-combustion carbon capture - a new amine-based solvent capture plant, designed for 95% CO₂ capture from the FCCU regenerator flue gas at up to 0.5 million tonnes per year, was permitted in October 2025⁹². However, the Final Investment Decision has not been taken and the project is now on hold, pending confirmation from the government of a funding pathway⁹³.

The site operates two delayed coking units. Desulphurisation and product

treating is handled by a suite of dedicated hydrodesulphurisation units: a gas oil HDS unit, a virgin HDS unit, a cracked HDS unit, a diesel HDS unit and a gasoline HDS unit, together with a Penex unit for light naphtha isomerisation. The refinery also operates two catalytic reforming units to produce high-octane reformate, and an aromatics extraction unit. A hydrode-alkylation unit produces benzene from toluene. Sulphur is recovered through two Claus SRU trains with a tail gas treatment unit.

The site is the first in the UK to produce sustainable aviation fuel at commercial scale, via a dedicated HEFA unit with a nameplate capacity of 150,000 tonnes per year, supplied to British Airways under a multi-year agreement. Separately, the FCCU is permitted to co-process limited volumes of renewable feedstocks - up to 5% tyre pyrolysis oil and 20% used cooking oil - alongside conventional crude-derived feedstocks, producing a partially renewable product slate from the existing conversion unit.

Refined products are distributed by pipeline to an extensive UK network, by rail and by road tanker, with crude received via the Tetney offshore single-point mooring terminal through a pipeline under the Humber estuary.

The wider Phillips 66 group is a leading integrated downstream energy provider operating with Midstream, Chemicals, Refining, Marketing and Specialties, and Renewable Fuels segments. At 31 December 2025, the company had total assets of \$73.7 billion⁹⁴. Phillips 66 Ltd, the UK subsidiary that owns and operates Humber, is a more straightforward entity than Esso Petroleum Company Ltd in that it operates a single primary asset: the Humber Refinery and its accounts relate to the refinery and the associated crude oil procurement and refined products marketing activities.

Phillips 66 Ltd reported turnover of \$23.3 billion for the year ended 31 December 2024, broadly flat against the previous year. Gross profit fell sharply from \$561 million to \$200 million, reflecting the deterioration in European refining margins during the second half of 2024 as market cracks returned to typical mid-cycle levels following the exceptional years of 2022 and 2023. Profit for the year was \$350 million (2023: \$570 million), supported by disposal gains and income from participating interests⁹⁵. The balance sheet shows net assets of \$2.3 billion, with the reduction from \$3.2 billion in 2023 driven primarily by \$1.2 billion of dividends paid to the parent rather than by operating losses.

Phillips 66 Ltd states explicitly in its statutory accounts that under a higher carbon cost regulatory scenario, industries subject to global competition

90 <https://www.eastmidlandsbusinesslink.co.uk/mag/featured/phillips-66-completes-acquisition-of-lindsey-oil-refinery-assets/>
91 https://assets.publishing.service.gov.uk/media/690dfd847ad122f854627d8/Application_Variation_V021_Permit_notice_-_31102025.pdf
92 <https://www.phillips66.co.uk/emerging-energy/carbon-capture/>
93 https://committees.parliament.uk/writtenevidence/160989/pdf/?__cf_chl_tk=n-hwxcwvcif48zo.SgfnnUGNNuq8JpDDq5_D7M85EljO4-1785387723-1.0.1.1-hQqGxnJoWKqEdR1bvVvjOXU38pRUJ.qsasqfvY6ACg

94 <https://www.sec.gov/Archives/edgar/data/1534701/000119312526139125/d64580dars.pdf>
95 <https://find-and-update.company-information.service.gov.uk/company/00529086/filing-history/MzQ4Mzc5NTUwMGFkaXF6a2N4/document?format=pdf&download=0>



would become less competitive, and that a focus on reducing UK territorial emissions without considering embedded emissions could lead to reductions in UK production and an increase in imports, “effectively moving industrial activity abroad”.

Phillips 66 group's 2026 global capital budget of \$2.4 billion, announced in December 2025, includes a newly announced multiyear gasoline quality improvement project at Humber, with an expected startup date in the second quarter of 2027, designed to enable production of higher-quality gasoline for higher-value global export markets⁹⁶. The budget also includes over 100 smaller projects across the refining portfolio focused on crude flexibility, feedstock optimisation and clean product yield improvement, a category in which Humber, with its wide crude slate capability, is well positioned to benefit.

It is harder to make a direct comparison with historic performance for Humber due to the way in which the wider business has been re-organised in the interim. The 2007 entity, ConocoPhillips Limited, generated the large majority of its turnover outside the UK⁹⁷. It segmental analysis indicates UK revenues of £3,095.3 million, Rest of Europe revenues of £7,343.5 million and Other revenues of £2,335.4 million. This points to a substantial international trading operation sitting alongside Humber refining, not a UK-refining-and-marketing vehicle comparable to EPC Ltd or Valero Energy UK Ltd in 2007. Return on net assets for ConocoPhillips was correspondingly very high in 2007 - 34.6% against tangible fixed assets of only £590.9 million on turnover of £12.8 billion - a pattern more consistent with an asset-light trading business than a capital-intensive refinery.

Stanlow (Essar (EET Fuels))

Stanlow is the smallest UK refinery, located on the Manchester Ship Canal in Cheshire. It directly employs over 700 people and processes 180 kbpd of crude oil each year, producing a range of oil products, including about one-sixth of Britain's transport fuels. Fuel processing at the site dates back to 1924 when Shell built a facility for bitumen production. The refinery was completed in 1952 and has since been expanded several times. In 2010 the refinery was bought by Essar⁹⁸ which is ultimately owned by the Ruia family⁹⁹. Capacity at the refinery was reduced in 2014 from just over 14 million tonnes per year to 9 million tonnes by closure of one of the crude distillation units.

A major turnaround in 2018, increased capacity to over 10.2 million tonnes per year¹⁰⁰, although now EET reports capacity to be back at 9 mt. This equates to 180,000 bpd and represents around 20% of the UK's refining capacity. Stanlow produces around 16% of UK road transport fuels, including 4.4 billion litres of diesel, 3 billion litres of petrol and 2 billion litres of jet fuel annually.

The refinery operates one crude distillation unit supported by a network of process furnaces with combined thermal input exceeding 500 MWth. A second distillation unit closed in 2014. The primary conversion unit is a fluid catalytic cracker, which includes a reactor-regenerator section, main fractionator column and CO boiler, with an associated gas separation unit. The £200 million cracker complex uses advanced technology to break heavy fraction molecules into new hydrocarbon combinations for petrol, diesel and chemical unit feedstocks. Energy from the cracker is harnessed by a power recovery train - the largest in Western Europe - generating 21 MW of electricity, powering the refinery with the surplus exported to the

⁹⁶ <https://investor.phillips66.com/financial-information/news-releases/news-release-details/2025/Phillips-66-announces-2026-capital-budget/default.aspx>

⁹⁷ <https://find-and-update.company-information.service.gov.uk/company/00529086/filing-history/MjAxMjAzNDgzMGFkaXF6a2N4/document?format=pdf&download=0>

⁹⁸ <https://www.eetfuels.com/history/>

⁹⁹ <https://www.essar.com/us/founding-family/>

¹⁰⁰ <https://fueloilnews.co.uk/2022/11/the-uks-refineries-past-present-and-future/>

grid^{101,102}.

Upgraded products are processed through an HF alkylation unit combining light olefins with isobutane to produce high-octane gasoline blendstock, and a platformer using a platinum catalyst to upgrade light fractions by reducing their hydrogen content. The upgraded stream produces LPG, chemical-grade benzene and toluene, and high-octane petrol components, feeding an aromatics plant producing benzene, toluene and xylene.

Desulphurisation is handled by two hydrodesulphurisation units and a dedicated hydrotreater, enabling production of ultra-low sulphur road fuels. The hydrodesulphuriser uses high temperature and pressure catalytic processes to remove sulphur from gas oil for diesel blending, and was extensively refurbished in the late 1990s to launch the UK's first low sulphur diesel ahead of EU requirements. In 2000 a £30 million hydrotreater 2 and gasoline 3-cut splitter were added to enable robust production of low-sulphur petrol.

Stanlow has a somewhat troubled financial history. The covid-19 pandemic hit the site hard leading to additional going concern disclosures in the 2020 accounts¹⁰³. Three chief executives resigned in fifteen months, and two city law firms and two auditors withdrew over governance concerns in relation to loans from Russian bank VTB¹⁰⁴. A \$130 million turnaround completed in May 2025 improved throughput and margins, and the site recorded record sales volumes following the Grangemouth and Lindsey closures¹⁰⁵. A further US\$100 million investment was made in installing and commissioning the UK's first hydrogen-ready furnace.

EET is pursuing an ambitious decarbonisation programme as part of the HyNet industrial cluster, centred on blue hydrogen production, but the programme is substantially behind schedule. The Final Investment Decision on the first unit, originally targeted for 2023, is now expected in the second half of 2026, pending a government revenue support agreement that remains unsigned after four years of negotiation¹⁰⁶. EET also has a separate scheme for capturing refinery emissions, which is also yet to take FID pending confirmation of government support.

Essar's financial results for the year ended 31 March 2025 reflect a severe deterioration despite an increase in market share following the recent refinery closures. Revenue was marginally higher than in the previous year despite more than two months of turnaround downtime, however the gross refining margin fell from \$12.9 /bbl to \$7.7 /bbl, while operational EBITDA (the measure most representative of underlying refinery performance) collapsed from \$253.9 million to \$2.0 million, with the pre-tax loss increasing from \$90.4 million to \$325.9 million. The Group depends heavily on receivables financing, inventory and trade finance facilities, as well as a material revaluation of its physical assets - 91% of reported equity is attributable to the revaluation¹⁰⁷.

Set against its peers, Stanlow's economics inside Shell already looked weak well before the 2011 sale. In 2007- a strong year across the sector, sitting within what the industry still refers to as refining's “golden age” of 2004–2008 - Fawley delivered an operating margin of 5.5% and a return on net assets of 21.9%; Pembroke, then under Chevron/Texaco ownership,

¹⁰¹ https://assets.publishing.service.gov.uk/media/6377652ee90e07284b829d26/FP-3139FN-V012_-_Variation_Notice.pdf

¹⁰² <https://www.eetfuels.com/our-locations/>

¹⁰³ <https://www.eetfuels.com/wp-content/uploads/2025/03/1-eouk-sep-20-financial-statements-signed.pdf>

¹⁰⁴ <https://www.source-material.org/essar-stanlow-vtb-russia-sanctions/>

¹⁰⁵ <https://www.essar.com/inthenews/essar-energy-transition-strengthens-its-business-with-completion-of-a-us130mn-turnaround-and-improvement-plans-worth-us350mn-annually-at-the-stanlow-refinery/>

¹⁰⁶ <https://committees.parliament.uk/writtenevidence/161611/html/>

¹⁰⁷ <https://www.eetfuels.com/wp-content/uploads/2025/11/EET-Annual-Report-2025-Final.pdf>



returned 3.79% and 15.4% respectively. Shell UK Limited’s downstream segment, which included Stanlow alongside UK marketing and a substantial oil trading book, managed a profit-before-tax margin of just 0.4% in the same year¹⁰⁸.

The comparison cannot be made refinery-for-refinery because Shell did not disclose Stanlow’s results separately, and the segment figure is diluted by low-margin trading turnover, but the scale of the gap is striking enough to suggest Stanlow was a genuine laggard within Shell’s UK portfolio, not merely a victim of general sector conditions. It is also worth noting that the sector’s remaining refineries today may look more resilient in part because the weaker assets with the exception of Stanlow have already closed - survivorship, rather than universal strength, may explain some of the current picture.

Essar’s decision to buy Stanlow in 2011 should not be interpreted as a distressed rescue. It formed part of a stated strategy of building roughly 1 mmbpd of global refining capacity by acquiring assets in Europe and Africa during a post-crisis downturn¹⁰⁹ - a leveraged roll-up, timed deliberately to buy developed-market capacity cheaply while Western strategics were retreating. The financing structure made the risk explicit from day one - of a total acquisition cost of US\$ 1,174.0 million, only US\$ 241.5 million was funded by share capital, with the balance covered by a US\$ 346.9 million related-party loan (on which interest was waived entirely, since the company was loss-making) and a US\$ 243.3 million drawdown against a US \$1.5 billion revolving credit facility. Net assets on completion were just US\$ 185.0 million against total assets of US\$ 2,810.2 million, a wafer-thin equity cushion for a capital-intensive, cyclical asset¹¹⁰.

The buyer also lacked two things Shell’s ownership had supplied largely invisibly a route-to-market for the refined products and trading capability, and deep refining-specific operational experience. Both gaps were clear in the post-acquisition 2012 accounts. There was a five-year crude supply agreement and an off-market product-offtake obligation with Shell itself and a range of trading agreements including with Valero. There was also an early reliance on receivables factoring and inventory sale-and-repurchase arrangements with Barclays, executed within months of the acquisition being completed.

Fourteen years on, Essar’s gamble has not paid off. Despite roughly £700 million of investment and a reported cUS\$ 5 /bbl improvement in Stanlow’s refining margin capability since 2011, EET Fuels’ 2025 results show gross refining margin collapsing from US\$ 12.9 /bbl to US\$ 7.7 /bbl, operational EBITDA falling from US\$ 253.9 million to just US\$ 2.0 million, and a pre-tax loss widening to US\$ 325.9 million, with 91% of reported equity now resting on a revaluation of physical assets rather than retained earnings. If anything, the underlying financial position looks more fragile today than in the first reported period after acquisition, not less.

The combination of a leveraged balance sheet, governance issues and an uncertain investment pipeline makes Stanlow appear to be the most financially vulnerable of UK refineries, with long-term viability highly dependent on policy commitments that have not yet been secured. Stanlow looks potentially operationally viable, but financially fragile – the refinery may be a decent asset trapped inside an overleveraged, expensive and governance-heavy corporate structure. The 2026 accounts will be critical in assessing whether management’s two-year Business Improvement Plan has restored sustainable profitability and strengthened the balance sheet, or whether more fundamental questions over the business’s long-term financial resilience remain.

108 <https://find-and-update.company-information.service.gov.uk/company/00140141/filing-history/MjAyNjEwNTQ2NWFKaXF6a2N4/document?format=pdf&download=0>
109 https://www.business-standard.com/article/companies/essar-buys-uk-s-stanlow-refinery-for-350-mn-111080100124_1.html
110 <https://find-and-update.company-information.service.gov.uk/company/07071400/filing-history/MzA2OTI5ODMwOWFKaXF6a2N4/document?format=pdf&download=0>

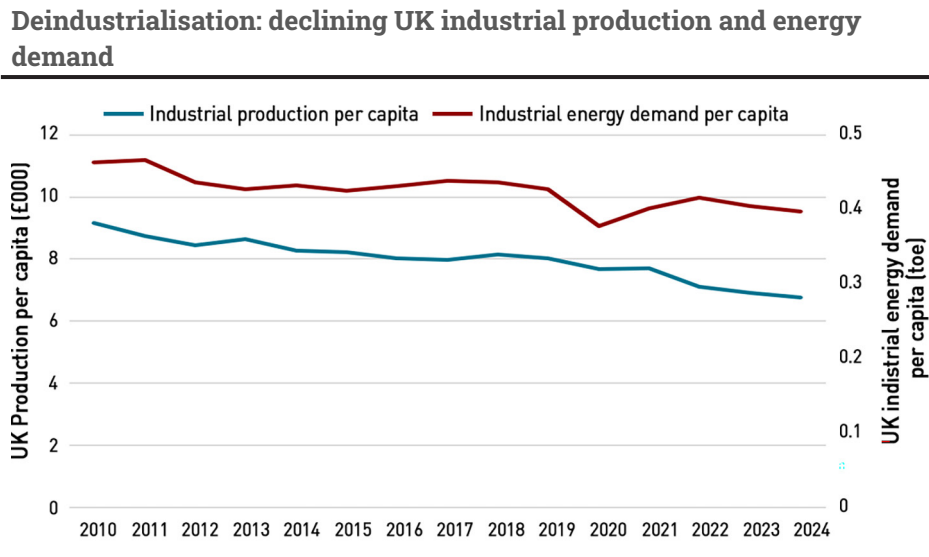
Appendix 4 – carbon pricing

Overview of the UK ETS

The UK Emissions Trading Scheme (“ETS”)¹¹¹ is the UK’s carbon market, created on 1 January 2021 after the UK left the EU ETS following the UK’s departure from the European Union (“Brexit”). It is a key policy instrument for achieving net zero by 2050, and aims to reduce greenhouse gas emissions in a cost-effective way. The EU Emissions Trading Scheme was launched in 2005 as the world’s first large-scale carbon market. The UK participated from the outset until leaving the scheme at the end of 2020 following Brexit.

The ETS seeks to apply a cost to activities such as fossil fuel power generation, manufacturing and air travel that, according to the Government, “better reflects the cost to society of the emissions they produce”. The government has legislated for the scheme to run from January 2021 to December 2030, (phase one). Further legislation is needed for it to run beyond 2030¹¹² (phase two). A consultation on phase two closed in April 2026 and is now under consideration by the Government¹¹³. The scheme is administered by the ETS Authority which is made up of various UK Government departments and the devolved governments of Scotland, Wales and Northern Ireland.

The ETS is a “cap and trade” system. The government places a cap on emissions, which is reduced over time - the cap was 156 million tonnes of CO₂ in 2021 and will fall to 50 million tonnes in 2030. The cap is divided into allowances (UK ETS Allowances (“UKAs”)), each allowing a participant to emit one tonne of CO₂ equivalent.



Source: Office for National Statistics UK Index of Production time series, Office for National Statistics population data and estimates, DESNZ Energy Consumption in the UK (ECUK): Final Energy Consumption Tables

Participants must acquire enough allowances to cover their emissions each year, with this need for allowances creating a market in which allowances are bought and sold. This market sets the carbon price which should be high enough so that, over time, it is cheaper for scheme participants, such as power generators and heavy industries, to introduce decarbonisation measures than to carry on emitting. The ETS covers power, heavy

111 <https://www.gov.uk/government/publications/uk-emissions-trading-scheme-uk-ets-policy-overview/uk-emissions-trading-scheme-uk-ets-a-policy-overview>
112 <https://www.nao.org.uk/wp-content/uploads/2025/06/uk-emissions-trading-scheme.pdf>
113 <https://www.gov.uk/government/consultations/extending-the-uk-emissions-trading-scheme-cap-beyond-2030/extending-the-uk-ets-cap-beyond-2030-english-consultation-document-html-version>

industry and aviation, and accounts for roughly a quarter of UK territorial emissions and has over 1,000 participants.

Allowances can be obtained through free allocation, government auctions or purchases in the secondary market. Auctions are the primary means by which companies acquire the UKAs needed to meet their ETS compliance obligations. In 2024 69 million allowances were auctioned – this will fall to 24 million in 2030.

A key feature of the UK ETS, like its European relative, is free allocation - installations judged to be exposed to carbon leakage risk receive some allowances free of charge in order to reduce their net carbon cost. The logic is that, without this protection, carbon pricing could simply push production offshore rather than cut global emissions. Free allowances are also intended to provide a financial incentive for companies to innovate and improve efficiency, thereby reducing their emissions. The ability to sell their excess free allocation on the secondary market provides a means of raising funds which can help cover these decarbonisation investments.

The number of free allowances issued to a company is based on their historic production levels, a benchmark comparing efficiency of production in its sector, a measure to reward the most carbon efficient companies, and the risk of carbon leakage.

In practice, carbon costs are not the only drivers of offshoring that leads to carbon leakage – high energy costs aside from the impact of carbon pricing have contributed to significant levels of deindustrialisation in the UK.

The UK ETS allows banking of allowances, enabling firms to carry forward unused allowances and smooth compliance costs over time rather than treating each year in isolation. In December 2025 the Government confirmed that banking would be permitted between phases one and two, removing the risk that allowances lose value at the end of the current phase. This is important since to date, the supply of allowances has exceeded demand. Government modelling for its 2025 traded carbon values assumes a surplus¹¹⁴ of allowances in the system, estimated at around 67 million in 2025, indicating that the market is structurally “long”, with more allowanc-

¹¹⁴ <https://www.gov.uk/government/publications/traded-carbon-values-used-for-modelling-purposes-2025/traded-carbon-values-used-for-modelling-purposes-2025>

es available than required for compliance. In a long market, firms can meet their obligations without significant scarcity, which tends to suppress carbon prices and weaken the incentive to decarbonise.

External commentary has also highlighted this surplus position as a key driver of relatively low and volatile UK carbon prices compared with the EU ETS. The expectation is that this surplus will decline over time as the cap tightens, but in the near term it continues to shape market behaviour and pricing dynamics.

Comparison with other carbon markets

According to the World Bank¹¹⁵, there are now 80 carbon pricing schemes globally, covering 28% of global greenhouse gas emissions. More countries, including Brazil, India, and Turkey, are implementing domestic carbon pricing frameworks, while others, including Zambia, Tanzania, Paraguay, and Vietnam, are planning to participate in international carbon markets.

Not all carbon pricing schemes are constructed the same way, with the distinction being important when interpreting the price-per-tonne figures being compared. Most developed-economy schemes, including the UK and EU ETS, are “cap-and-trade” schemes where the government sets an absolute, declining limit on total emissions across covered installations, issues allowances equal to that limit, and lets the market set a price for the resulting scarcity. Because the cap falls over time, the number of allowances in the system shrinks, scarcity is built in by design, and the price is a genuine signal of the marginal cost of staying within a shrinking pool of permits¹¹⁶.

A number of other schemes, including China’s national ETS, now the world’s largest carbon market by covered emissions, operate instead on an “intensity-based” or “baseline-and-credit” model. Here the government sets an emissions-intensity benchmark per unit of output (for example, tonnes of CO₂ per MWh generated) rather than a fixed ceiling on total emissions. Installations that beat their benchmark generate tradeable credits while those that fall short must buy them.

¹¹⁵ <https://openknowledge.worldbank.org/entities/publication/e5f6e755-e6a6-4d2c-927a-23b5cc8a9b03>

¹¹⁶ <https://www.iosco.org/library/pubdocs/pdf/IOSCOPD774-note.pdf>



International comparison of Emissions Trading Schemes

Country	Sectors	Coverage of greenhouse gas emissions (%)	Carbon Price (US\$)
UK	Domestic aviation Industry Power	c25%	48
South Korea	Maritime, waste Domestic aviation Transport Buildings Industry Power	c89%	8
California (USA)	Transport Buildings Industry Power	80%	35
Quebec (Canada)	Transport Buildings Industry Power	77%	35
New Zealand	Forestry Maritime Waste Domestic aviation Transport Buildings Industry Power	> 50%	39
China	Power	> 40% of CO2 emissions	13
EU	Maritime Domestic aviation Industry Power (Transport and buildings will also be included under the EU's separate ETS 2 scheme)	c38%	70
Switzerland	Domestic aviation Industry Power	12%	65

Source: National Audit Office analysis of International Carbon Action Partnership data

Unlike the cap-and-trade model, intensity-based schemes allow total covered emissions to rise as long as output grows proportionally, because there is no absolute cap constraining the aggregate and scarcity, where it exists, comes from the tightening of the intensity benchmark rather than from a shrinking pool of allowances¹¹⁷. China has signalled it intends to shift its ETS toward an absolute cap by 2027, but it operates on the intensity-based model today. China alone accounts for a large share of the emissions now nominally “covered” by carbon pricing globally¹¹⁸.

Carbon pricing

The Government explicitly states that the purpose of carbon pricing is to “apply a cost to activities like fossil fuel power generation, manufacturing and air travel that better reflects the cost to society of the emissions they produce”. But this is an incomplete framing of the problem as it ignores the benefits of using fossil fuels. A better framework would be one that sought to reflect the net social impact of an activity, not just its negative externalities.

For example, the refining sector (and energy production more broadly) doesn’t just emit greenhouse gases, it also delivers energy security (reduced dependence on imports), system resilience (local capacity in shocks or crises), economic value (jobs, tax base, industrial capability), and strategic optionality (ability to respond to geopolitical disruption). These are positive externalities or public goods and are not fully priced in markets either.

117 <https://www.iea.org/reports/chinas-emissions-trading-scheme>
118 <https://ieefa.org/resources/chinas-emissions-trading-system-ets-reforms-track-needs-robust-enforcement>

Under the existing, one-sided framework, if leakage is not adequately prevented, for example where UK refining faces a carbon cost, but imports do not face an equivalent cost, the policy effectively assumes that a tonne of emissions avoided in the UK is a net benefit, regardless of where production moves. If production shifts overseas, where emissions are the same or higher, and the UK loses domestic capacity then global emissions may not fall, and positive domestic externalities are lost. This is not just inefficient, it actively reduces welfare.

Furthermore, refineries are not just “emitters”, they are critical infrastructure for transport fuels (including aviation and defence), providers of feedstocks for petrochemicals, plastics, pharmaceuticals and part of emergency supply chains (eg during supply disruptions). These are strategic goods where markets alone may not deliver optimal outcomes. A purely carbon-cost-based framework treats refining as a standard industrial activity and ignores its systemic importance.

As a result the Government becomes exposed to calls for ad hoc sector-specific support in order to protect strategically important industries, when a more coherent policy approach would seek to balance positive as well as negative externalities from the outset.

Evolution of UK carbon prices

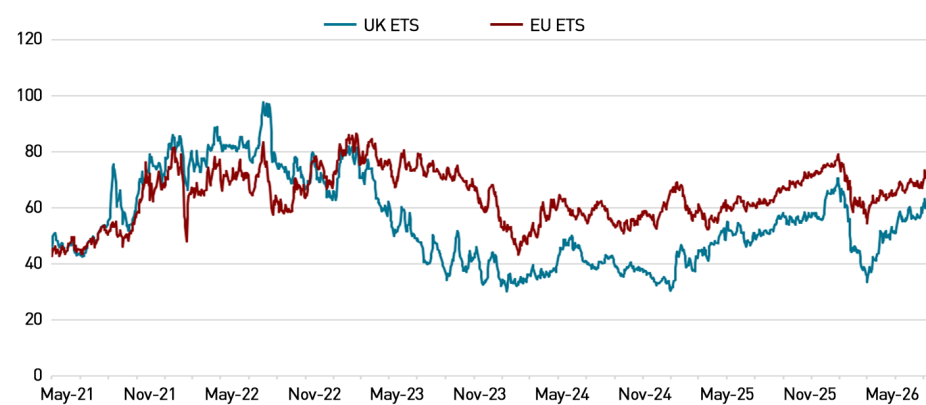
While the price of UKAs is set by the market, the ETS Authority has a mechanism – the Auction Reserve Price (“ARP”) - to protect against price decreases that could disincentivise investment in decarbonisation. The ARP is set at £22 per tonne of CO₂ equivalent, and is the lowest price at which UKAs can be sold at auctions. The value was set in 2021 and was intended to be a temporary measure that would be phased out as the market matures. To date the price of UKAs has not fallen below this value and in December 2025 the Government announced¹¹⁹ that the ARP will be maintained at its real value, implementing an inflation-based increase to £28 which applied from April 2026, and to increase the value annually by inflation from 2027.

The UK ETS also has a Cost Containment Mechanism (“CCM”) that is intended to protect against sustained high prices. In December 2025, the Government confirmed that the threshold for CCM activation will continue to be triggered if the average price for one allowance on the secondary futures market exceeds three times the average price of the preceding two-year period for six consecutive months¹²⁰.

In practice, this is a very high hurdle that is slow to take effect, and does not automatically drive market intervention. Activation only requires the UK ETS Authority (the UK, Scottish and Welsh Governments and the Northern Ireland Executive) to meet and consider whether to act – there is no obligation to actually do so. This stands in contrast to mechanisms such as California’s Cap-and-Trade programme, where breaching a price tier automatically releases additional allowances from a reserve, without the need for a discretionary decision¹²¹. The UK mechanism has been triggered twice to date, in December 2021 and January 2022, when allowance prices breached the (then lower) trigger thresholds. On both occasions the Authority met, published only a brief outcome statement rather than minutes of the discussion, and concluded the market was functioning normally, taking no action¹²².

119 <https://www.gov.uk/government/consultations/uk-emissions-trading-scheme-future-markets-policy/outcome/uk-emissions-trading-scheme-main-authority-response-to-the-future-markets-policy-consultation-accessible-webpage>
120 <https://www.gov.uk/government/publications/uk-emissions-trading-scheme-uk-ets-policy-overview/uk-emissions-trading-scheme-uk-ets-a-policy-overview>
121 <https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cost-containment-information>
122 <https://www.gov.uk/government/publications/uk-emissions-trading-scheme-ets-authority-cost-containment-mechanism-decisions>

UK and EU ETS prices (£ /tonne)



Source: Bloomberg, ECB EUR/GBP exchange rate

In 2011–12 the UK Government became concerned that carbon prices under the EU ETS were too low and too volatile to provide a meaningful incentive for decarbonisation, particularly in the power sector. In response, it introduced the Carbon Price Floor¹²³ (“CPF”) from April 2013, implemented through the Carbon Price Support (“CPS”) as a tax on fossil fuels used in electricity generation. The CPS was designed to “top up” the prevailing carbon price to a target level, ensuring that UK generators faced a higher and more predictable carbon cost than under the EU ETS alone.

The CPF taxes fossil fuels used to generate electricity via CPS rates set under the Climate Change Levy. The price floor consists of two components which are paid for by energy generators in two different ways: (i) The EU ETS allowance price (later UKA prices); and (ii) the Carbon Support Price, which tops up the ETS prices, to the carbon floor price target. When the CPF was introduced, it was due to rise every year until 2020 (to a price of £30/tCO₂), however in the 2014 Budget the Government announced that the CPS component of the floor price would be capped at a maximum of £18/tCO₂ from 2016 to 2020 to limit the competitive disadvantage faced by business and reduce energy bills for consumers. This price freeze was subsequently extended and no further increases were introduced.

Since the implementation of the CPF there were significant reductions in coal electricity generation, with the final coal plant closing in September 2024. Since then there has been no meaningful decarbonisation delivered by the CPF since the use of gas generation is driven by a need to meet electricity demand when output from low carbon generation and renewables is insufficient. The additional costs of the CPF are ultimately borne by domestic and business consumers through higher wholesale electricity prices, meaning the competitiveness of energy intensive industries was being undermined for no real benefit. As a result, the Government announced¹²⁴ in April 2026 that Carbon Price Support will be removed from April 2028.

UK carbon prices sit in an uncomfortable middle ground. In practice, ETS prices remain too low to incentivise CCS investment decisions - UK carbon capture is financed not through the ETS price but through bespoke government revenue-support contracts negotiated bilaterally under the Track-1/Track-2 cluster sequencing process. The projects that have reached FID, including Northern Endurance Partnership and Net Zero Teesside, only confirmed their investment decisions after those government support contracts were agreed, and not in response to any ETS price signal. Projects still awaiting FID are largely stalled on funding allocation and transport-and-storage infrastructure access, not on carbon price levels.

That leaves the ETS doing little to pull forward decarbonisation invest-

¹²³<https://commonslibrary.parliament.uk/research-briefings/sn05927/>

¹²⁴ <https://questions-statements.parliament.uk/written-statements/detail/2026-04-16/hcws1519>

ment. Instead it imposes a real, volatile cost. UK carbon allowances have ranged from £34 /tonne in early 2025 to £73 /tonne in January 2026 and stand at around £59 /tonne today and are imposed on energy-intensive, trade-exposed businesses competing against international producers facing no equivalent costs.

With free allocation for carbon-leakage-exposed sectors due to be phased out from 2027 as the CBAM takes over, that exposure is set to grow. The result is a carbon price that fails to drive UK decarbonisation investment, while adding to cost burdens that push UK production out of business in favour of imports from countries with no carbon price at all, and often dirtier energy, an outcome that delivers no global emissions benefit, since production simply moves rather than falls.

Harmonisation with the EU ETS and the Carbon Border Adjustment Mechanism

The UK’s Carbon Border Adjustment Mechanism (“CBAM”) is a new tax¹²⁵ which “will ensure that highly traded, carbon intensive goods which are imported into the UK face a comparable carbon price to that paid by manufacturers producing the same goods in the UK”. This compares with goods manufactured in the UK which are subject to the ETS. The CBAM will apply from 1 January 2027 to goods from the following industrial sectors: aluminium, cement, fertiliser, hydrogen, iron and steel.

The EU introduced its CBAM¹²⁶ in 2023, with a transitional phase currently underway and full financial obligations due to begin in 2026. It also applies initially to a limited number of industries considered to be both emissions-intensive and exposed to international trade, including iron and steel, cement, fertilisers, aluminium, hydrogen and electricity.

The UK’s CBAM policy is less developed than the EU’s and remains subject to consultation and refinement. The UK version is expected to cover a broadly similar set of sectors, although the precise scope, methodology and interaction with the UK ETS are still being finalised. Notably, neither the EU nor UK CBAM currently extends to refined petroleum products, leaving sectors such as refining exposed to carbon costs domestically while competing against imports that do not face an equivalent charge.

The EU CBAM forms part of a broader industrial and climate policy framework linked to the EU ETS, whereas the UK approach is being developed primarily as a tax instrument by HM Treasury. This difference in institutional ownership has contributed to a slower and less detailed articulation of the UK mechanism, with industry raising concerns about uncertainty over its eventual design and operation.

The EU CBAM is already in a transitional phase with detailed reporting requirements in place and a clearly defined methodology for calculating embedded emissions and carbon costs. By contrast, the UK CBAM is not due to be implemented until 2027 and remains at the consultation stage, with key elements including calculation methods, treatment of indirect emissions, benchmark setting and administrative processes still to be finalised. The UK has indicated a broadly similar sectoral approach but has not yet set out the full interaction with the UK ETS, including how the CBAM will evolve as free allowances are reduced.

The EU CBAM also has a more developed institutional and enforcement structure, including monitoring, reporting and verification requirements and arrangements for importers to purchase and surrender CBAM certificates linked to EU ETS prices. The UK has yet to publish equivalent detail, leaving open questions around compliance burdens, enforcement mechanisms and how effectively the system will prevent circumvention. This creates uncertainty for businesses about future carbon costs and competitive impacts.

¹²⁵ <https://www.gov.uk/government/publications/introduction-of-carbon-border-adjustment-mechanism/carbon-border-adjustment-mechanism>

¹²⁶ https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en

The UK has also committed to introducing its own reporting framework for the CBAM, and there is no indication it will be fully aligned with the EU system. In practice, this makes duplication of reporting requirements almost inevitable, particularly for exporters already subject to EU CBAM. The result is likely to be parallel compliance regimes rather than a single, coherent framework, creating additional costs for UK businesses.

The effectiveness of the CBAM in preventing carbon leakage will depend both on coverage and implementation. Partial sectoral coverage risks “leakage within the boundary”, where emissions-intensive intermediate products are imported and then processed within the UK. More broadly, CBAMs introduce additional costs into supply chains, which are likely to be passed through to consumers, contributing to upward pressure on prices, particularly in construction and manufacturing, ultimately driving inflation. While both the EU and UK mechanisms are designed to level the playing field, their limited scope and phased implementation mean that, in the near term, significant exposure to carbon leakage remains for sectors outside its coverage.

The relatively modest inflationary impact identified in much of the CBAM literature reflects its limited sectoral scope. The EU mechanism applies primarily to a small number of emissions-intensive intermediate goods and excludes most consumer products, as well as key inputs such as natural gas, despite imports being included. If the CBAM were extended more broadly to cover a wider range of goods, including final consumption items and energy products, the inflationary impact would be materially higher.

More broadly, this highlights a central limitation of net zero policy, which focuses on territorial production emissions rather than emissions associated with consumption. The focus on production emissions effectively incentivises offshoring of manufacturing in favour of imports. The CBAM partially addresses this, but only for a narrow set of sectors. A fully consumption-based approach would apply carbon costs across all imports, exposing the true cost of decarbonisation. That has not been pursued, in part because the resulting increase in consumer prices would be more visible and politically difficult to sustain.

The UK Government has indicated that it intends to pursue closer alignment, or “linking”, between the UK ETS and the EU ETS, arguing that alignment is necessary to reduce the risk that UK exports face additional carbon costs at the EU border. This is particularly sensitive in Northern Ireland, with trade body Energy UK saying that if the EU CBAM were not to apply in Northern Ireland, it could call into question the legal framework supporting post-Brexit trading arrangements.

However, full harmonisation of the UK and EU ETS is not strictly necessary for CBAM purposes, and the Government’s case for pursuing it is weak. The

EU CBAM allows importers to deduct verifiable carbon costs already paid in the country of origin from their CBAM liability. In practice, this means that UK exporters subject to the UK ETS will only face a CBAM charge to the extent that the effective carbon price they have paid is below the EU ETS price. The EU CBAM Regulation does not require identical ETS design or architecture; rather, it requires that carbon pricing be measurable, verifiable, and attributable to the goods concerned, conditions which the UK ETS is capable of meeting. The disadvantages of harmonisation outweigh any benefits and therefore the plans should be abandoned.

The Government’s preferred route to full mutual exemption is formal ETS linking, as agreed in principle at the May 2025 UK–EU Summit. Linking would allow goods originating in either jurisdiction to be treated as subject to an equivalent carbon pricing regime, removing the need for CBAM adjustments. This is a legitimate objective for UK industries that export significant volumes of CBAM-covered goods to the EU, such as steel, aluminium, cement, fertilisers and hydrogen. However, these sectors represent only a subset of UK ETS participants. For industries that do not materially export CBAM-covered goods to the EU, the CBAM exposure argument for alignment does not apply. In such cases, harmonisation, particularly where it implies price convergence with the EU ETS, would increase carbon costs without providing a corresponding benefit.

Market evidence suggests that expectations of alignment are already influencing UK carbon prices. In February 2025, following the Prime Minister’s announcement of the Government’s intention to pursue ETS linking, UKA prices rose by approximately one third. The current price differential between UK and EU allowances remains material (of the order of £10–15/tCO₂), implying that convergence would impose a significant additional cost burden across much of the UK ETS-covered economy.



Abbreviations

API	American Petroleum Institute (used in the measure of a petroleum liquid’s density relative to that of water)
ARA	Amsterdam–Rotterdam–Antwerp
bbl	Barrel
bpd	Barrels per day
CBAM	Carbon border adjustment mechanism
CCS	Carbon capture and storage
DESNZ	Department for Energy Security and Net Zero
ETS	Emissions trading scheme
FCC	Fluid catalytic cracker
FID	Final Investment Decision
kbpd	Thousand barrels per day
LPG	Liquid petroleum gas
mmbpd	Million barrels per day
mt	Million tonnes
NCI	Nelson Complexity Index
ULSD	Ultra-low sulphur diesel
WTI	West Texas Intermediate



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