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OEUK – UK produced gas and its role in future security of supply

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February 2026

Project reference: P1659

UK gas system – key takeaways

The UK still needs gas – NESO's 10-year forecast for total GB demand estimates in 2026 the UK will use 53.6 bcm, by 2035 this falls to 53.3 bcm[1] (0.6% drop). Domestic supply is a crucial part of the gas mix and will be for years to come

Supports jobs, communities and UK tax revenues

- 115,000 jobs[2] across the UK supported by the oil and gas sector

The present policy framework is accelerating the decline in production

- Investment needed to slow the decline or maintain rates
- Steep production declines have been stopped previously
- Despite the UKCS being a mature basin, there are still opportunities extract more oil and gas

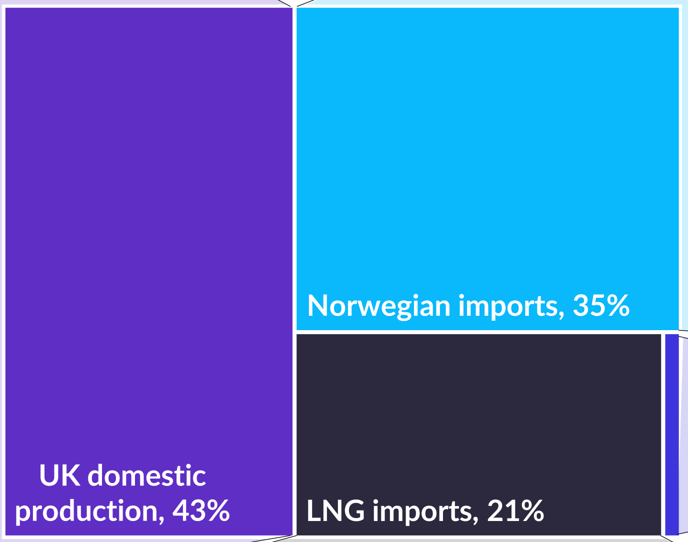
Reducing production will result in a rise in LNG imports to make up the shortfall

The current fiscal environment is not encouraging investment

- UK headline tax is 78% until March 2030
- The trigger price for gas, to determine 'normal' pricing conditions, is too low

Current production forecasts are not set in stone and subject to change based on investment plans

UK annual gas supply (2020-2024)[3]



The bulk of the gas imported from Norway is transported through pipelines to the UK

- Contracted volumes for reliant current supply
- Low greenhouse gas emissions

Also supplies mainland Europe, with long term contracts in place

Norwegian production has been predominantly flat to date, but the basin is maturing

- Production is on the brink of decline
- The Norwegian Offshore Directorate forecasts three future decline scenarios – two of which show the start of steep decline rates after 2026
- This could result in less gas available for supply

Interconnectors (1%)

- Bacton to the Netherlands and to Belgium.
- Contribution to energy supply is minimal

Primary sources for LNG imports are USA and Qatar

- Gas produced overseas, put into liquid form, shipped to UK then regasified for use
- -> Higher GHG emissions than domestic production (3 times more on average)
- Will be source to 'fill the gap' if domestic production levels drop
- Does not provide the jobs and tax benefits of domestic production

Gas storage

- Crucial for energy security and resilience to demand peaks
- UK has capacity for only 10 days of demand (January 2025 average demand)
- Investment is needed but there are domestic opportunities

[1] NESO Natural Gas Demand Summary ED3 2025 – Ten Year Forecast: Total GB Gas Demand (Excluding exports and shrinkage) – NESO considers this to be its "best view of future demand"
[2] OEUK Economic Report 2025
[3] Chart shows five-year average gross UK annual gas supply (2020-2024), from DESNZ's Gas system in transition consultation document

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UKCS Gas Infrastructure Report

This report provides an overview of domestic gas production, the current challenges, the upside potential and risks of failure to maximise economic recovery. Oil production is equally as important to the energy mix and is intertwined with gas production. Westwood produces its own production and economic models in its in-house Atlas platform, using a 'bottom-up' approach. The models project future production at an individual field and processing hub level based on historic trends and information such as drilling plans or well workovers that would impact future production rates. When combined, these forecasts give a view on future UKCS production. Cessation of production is based on when the pre-tax operating cashflow of the field and/or hub goes negative.

In contrast, the NSTA implements a 'top-down' approach for production forecasts, whereby future production is forecast based on basin-level decline assumptions, based on informed judgement and guided by most recent survey data available (including the investment plans from operators at the time of surveys). The NSTA applies a 'stylised compound' decline rate to production on the UKCS scale, which was 12% annual decline in gas production volumes in its November 2025 forecast. The previous rate in 2024 was an 11% year-on-year decline, and for context was only 5% in 2016. The NSTA states that "The projected production profiles are deliberately stylised to avoid the impression of spurious accuracy".

Westwood's data is derived from publicly available sources, and its analysis incorporates a comprehensive range of technical, commercial and industry information. Government-published data is included as one component and is assessed alongside company disclosures, market intelligence and Westwood's own expertise to produce an independent evaluation.

UK gas production overview

Gas volumes are often measured in billion cubic metres (bcm) - 1 bcm is enough to provide heat for almost 1 million homes for a year[1]

Steep UK gas decline is not inevitable

- Production peaked in 2000 and fell sharply until 2013. Production rates largely stabilised until 2022, during which time the industry was focussed on maximising economic recovery in spite of commodity price volatility, showing that the current decline could be arrested given the right investment environment

UK domestic production still matters for energy security

- In 2024, the North Sea Transition Authority (NSTA), reported that UK produced gas supplied 39.2% of UK gas demand. Piped gas from Norway supplied 45.5% and LNG imports contributed 15.1%

Domestic supply also matters for environmental impact

- In 2024, the NSTA reported that LNG imports had a GHG emissions intensity of 85 $kgCO_2$/boe whereas UK domestic production was 28 $kgCO_2$/boe. Newer UK field developments have an even lower emissions intensity which is more competitive with Norwegian piped gas (which had an average emissions intensity of 8 $kgCO_2$/boe) and offers energy security and jobs benefits

LNG has reshaped the market

- The rise of LNG in the last 10 years has changed the dynamics of the gas market, reshaping gas trade and pricing systems and bringing more choice for gas imports but also higher emissions and higher, globally contested, prices

The headline tax rate for oil and gas companies is 78%

- In 2022, the Energy Profits Levy (EPL) was introduced to recuperate tax revenues during the period of exceptionally high oil and gas prices (which peaked at US$122/bbl and 414 p/therm). Initially it was set at a rate of 25% with an end date of 2025, but through various Budgets has increased to 38% with an end date of 31 March 2030
- There is a mechanism to trigger an end to the EPL when commodity prices return to 'normal' levels. In January 2026, Brent oil spot price averaged US$62.5/bbl, below the threshold of US$74.21/bbl. The higher tax rate remains in place due to gas prices - the gas price threshold is 59 pence/therm. In January 2025, NBP spot price averaged 88 p/therm, with a peak of 106 p/therm due to a cold weather snap

Fiscal conditions are constraining investment in UK domestic production

- As a result, the production decline rate is increasing again. This will lead to an earlier cessation of production of fields and their processing hubs, which will increase the reliance on LNG imports to fulfil the demand. In October 2025, the NSTA reported that 42 development wellbores were drilled and completed in 2025, down from the 74 completed in 2020

Domestic production supports jobs across the country

- UK gas production arrives onshore at 12 processing terminals, located in Shetland, NE Scotland, Teesside, Dimlington, Bacton and Barrow - early closure risks the loss of jobs, skills & supply chain capability

Pipeline systems are complex and interconnected

- In 2025, 75% of gas throughput volumes were produced from fields which also relied on a liquids pipeline system

Subsurface opportunities remain

- There are opportunities in the subsurface to improve the production outlook for the UK. These would make business sense for investment with the right fiscal conditions

UK gas storage is limited and requires investment

- Current capacity is sufficient for just 10 days of demand at peak times (January 2025 average demand), almost half is at the Rough facility, which could cease this year without investment

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Source: Westwood Energy Atlas

[1] Based on DESNZ Review of the Average Annual Domestic Gas and Electricity Consumption Levels (March 2025) and TWh:bcm conversion used in DESNZ's Gas system in transition consultation document

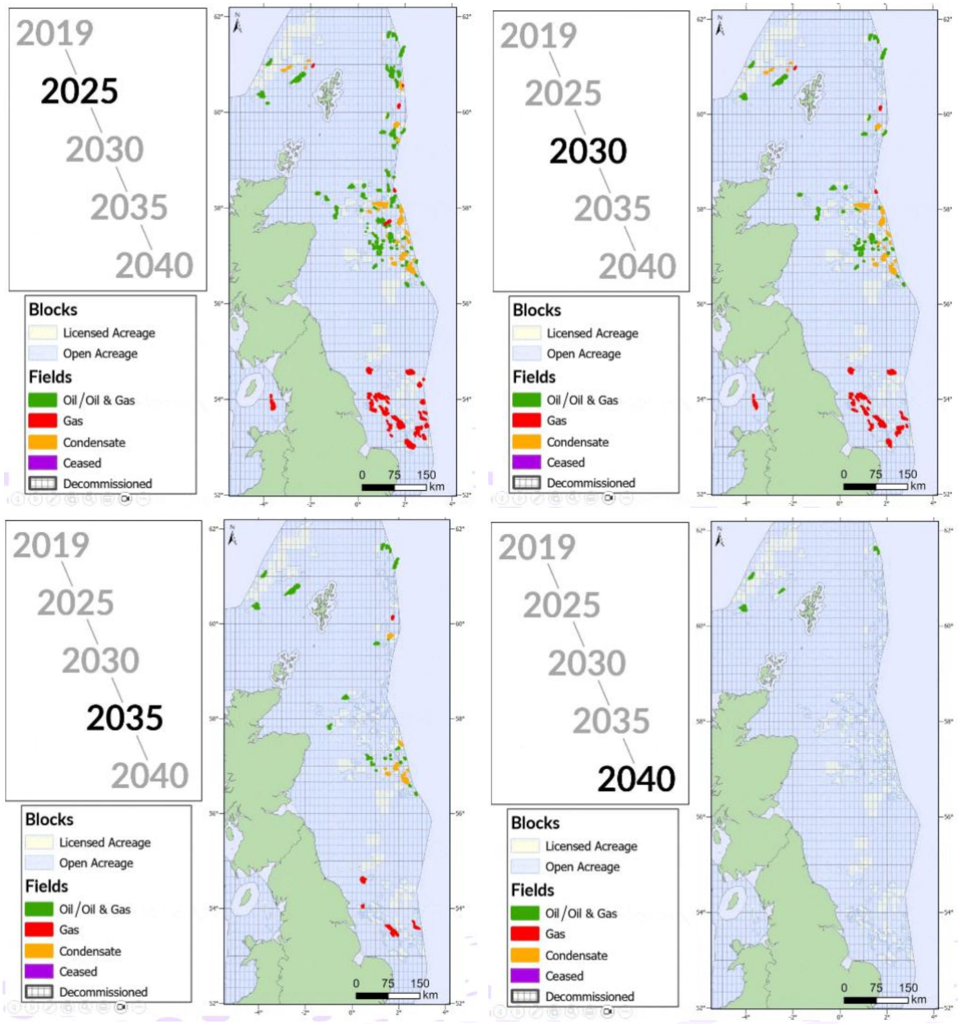
The cost of underinvestment

The UK has an enviable position with access to natural resources and renewable energy sources to supply a large proportion of its energy demand. Investment can prevent early cessation of production and support jobs

- Maintaining UK gas and oil production is challenging, but since 2013 the sector arrested the steep rate of decline prevalent since 2001 through continued investment. Domestically produced liquids and gas should continue to be a key part of UK energy supply
- Maximising economic recovery from UK fields supports UK jobs offshore and onshore, including in oil and gas companies, the supply chain, at terminals across the country, and locally supportive regions. 115,000 jobs[2] across the UK are supported by the oil and gas sector
- Accelerated decline rates will result in the early closure of fields resulting in a 'disappearing offshore landscape'
- Investment is needed to sustain production levels. The level of investment directly impacts the rate of production decline. New wells, well workovers, enhanced recovery techniques and equipment upgrades (such as compressors) help to maintain production rates. Investment also supports service sector jobs and maintains longevity of terminal operations
- Investment must make business sense. In the UK, many companies have overseas opportunities also competing for capital. The sector is currently paying a windfall tax in non-windfall commodity price conditions. The windfall tax (EPL) is acting as a barrier to near-term investment
- The interconnectivity of the gas and liquids pipeline infrastructure presents a 'house of cards' risk to offshore production
    - *Of the top ten offshore production hubs in the UK, which account for 48% of total production in 2026, no two hubs have the same liquids and gas export routes*
    - *Four hubs, accounting for 21% of total gas production in 2026, are reliant on the Forties Pipeline System. These hubs each have different gas export routes*

[2] OEUK Economic Report 2025

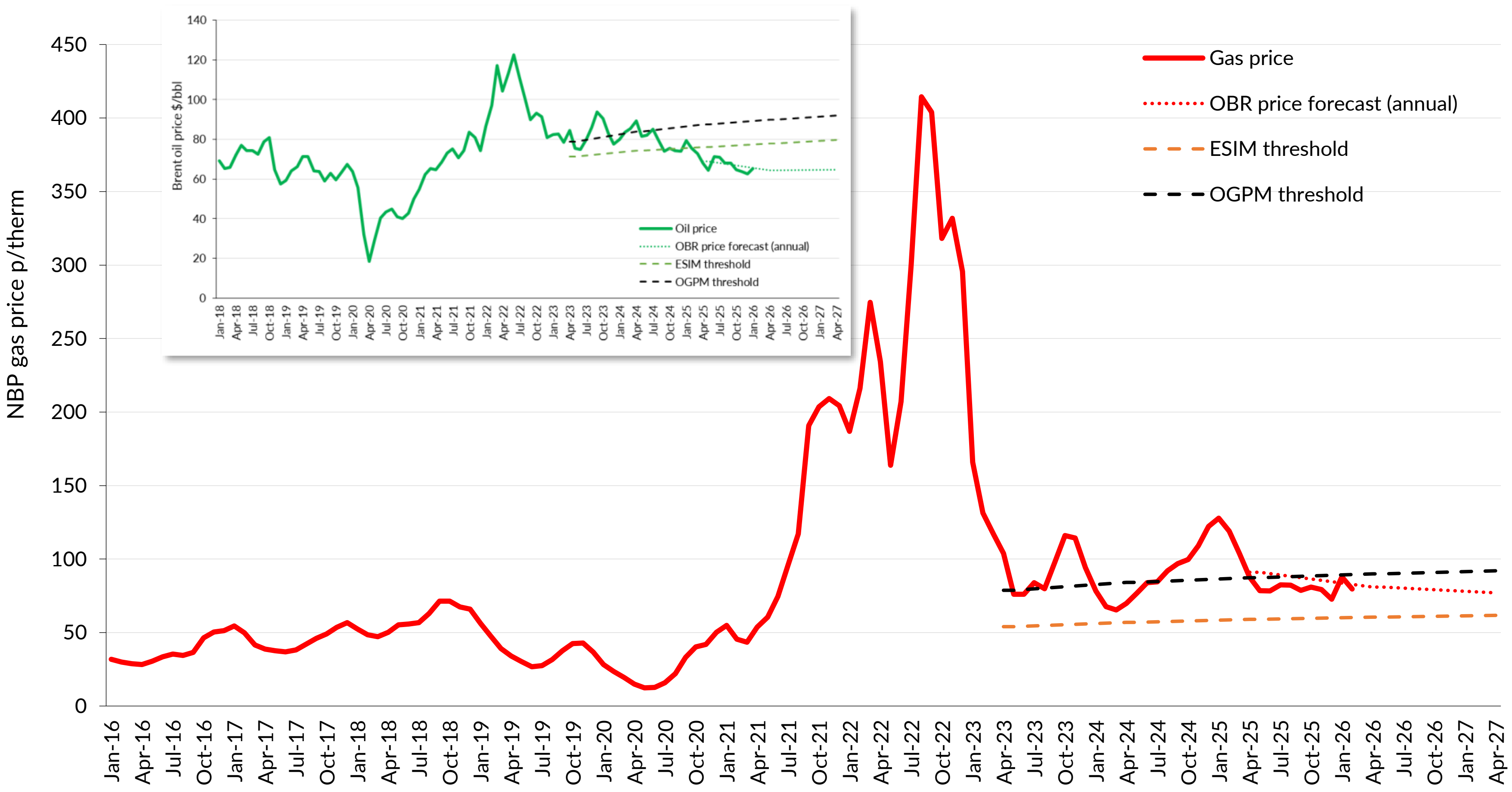
Impact of reduced investment – fields ceasing production



Source: Westwood Energy Atlas

Setting the right baseline for windfall tax

The EPL was introduced in 2022 as 25% temporary surcharge on the extraordinary profits of oil and gas companies operating on the UKCS, with a clause to end on 31 December 2025. It is now set at 38% and to end on 31 March 2030 or earlier if prices fall



Note: UK oil and gas companies pay 30% Corporation Tax, 10% Supplementary Charge and 38% EPL
Corporation tax for UK non-oil and gas companies with profits > £250,000 is set at 25%

- The Energy Security Investment Mechanism (ESIM) was implemented to trigger the end of the EPL when prices returned to 'normal' levels
- ESIM threshold prices are based on 20-year historic price averages, which do not fully capture changes to the gas market due to the rise of LNG
- Growth in the LNG market during this period drove gas price volatility. In 2019, this resulted in an annual price of 35 p/therm due to supply glut. In 2022, European demand caused price escalation resulting in an annual average of 262 p/therm, with a monthly peak of >400 p/therm
- The ESIM threshold is lower than the 'new normal' for European gas prices
- **Oil and Gas Price Mechanism (OGPM)** is proposed to replace the EPL to raise tax revenues during periods of high oil and gas prices. Proposed gas threshold price is 90 p/therm in 2026/2027 tax year. OBR price forecast is 81 p/therm for the same period
- For the 2025/2026 tax year to date, the gas price is averaging 81.3p/therm, which is 37.8% higher than the ESIM threshold and only 7% lower than the proposed OGPM high price trigger point
- By comparison, the average oil price for 2025/2026 year to date is 12.6% lower than the ESIM threshold price and 26% lower than the OGPM trigger price
- Under the OGPM definition, the oil and gas sector fell out of 'windfall conditions' in April 2024, on a six-month average price basis

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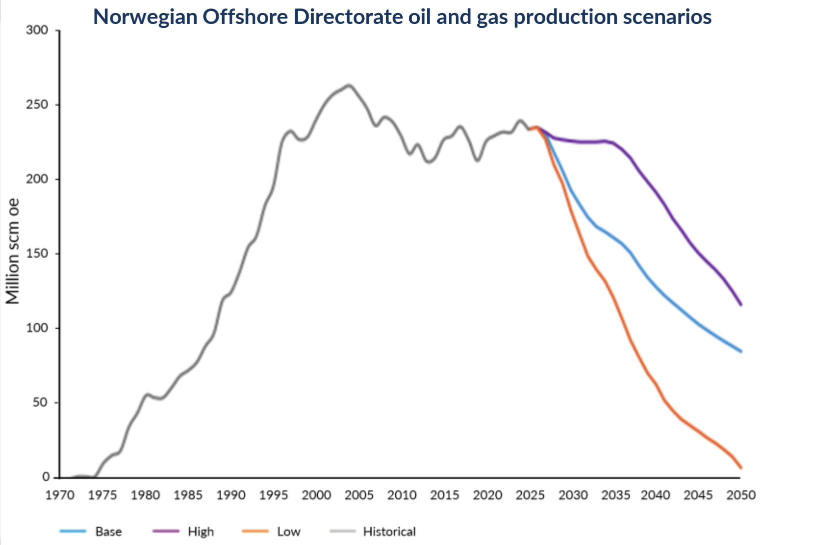
Source: NBP daily spot price for gas from Reuters, Brent oil spot price from EIA
EPL price threshold and OGPM trigger prices sourced from HM Treasury

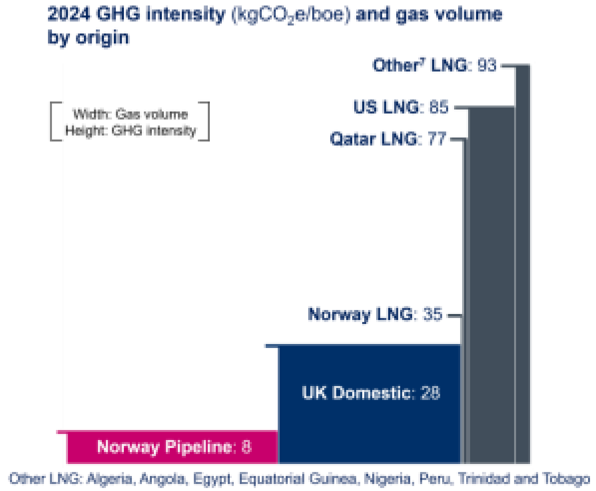
Domestic supply for domestic demand

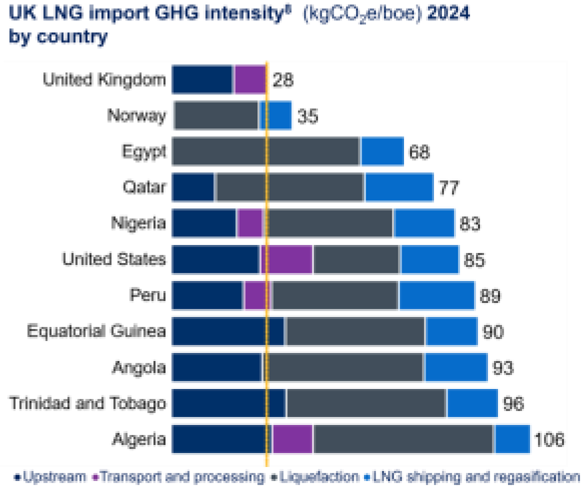
In 2024, UK gas production supported 39% of UK gas demand, with imported LNG accounting for 15%[1]. Accelerating the decline of UK production will increase the % share of LNG in the supply mix in the near to mid term

- There is a significant risk of large **UK production** hubs closing before 2035 due to constrained investment. This presents a viable risk of major pipeline infrastructure routes and terminals ceasing early due to low volumes and causing a 'house of cards' impact on their remaining entrants
- **Norway piped gas** supplies are contracted o the UK and the European continent. Norway's basin is maturing and the Norwegian Offshore Directorate forecasts three future decline scenarios – two of which show the basin in decline post 2026
    - Lower production rates would result in reduced piped gas volumes available for supply contracts across Europe and the UK
    - The Norwegian Government is advocating for further developments and exploration & appraisal to mitigate future production declines. The sector is pushing to maintain plateau production rates out beyond 2035
- **Liquified natural gas (LNG) is imported** to supplement the demand gap between domestic production, piped gas, renewables and other sources for UK energy demand. As LNG is produced in other regions, then liquified for transport, then re-gasified for use, it carries higher greenhouse gas (GHG) emissions intensity



Source: Sodir The Shelf in 2025 (https://www.sodir.no/en/whats-new/publications/reports/the-shelf/the-shelf-in-2025/oil-and-gas-on-the-ncs-moving-forward/)





- The **expansion of offshore wind** is falling behind schedule and is unlikely to be operational in time to offset declining domestic gas production or the potential for reduced pipeline imports from Norway or LNG
    - Although the AR7 Contract for Difference round (January 2026) delivered a strong set of results, its outcome effectively rules out the UK achieving 43 - 50 GW of operational offshore wind capacity by 2030, as envisaged under Clean Power 2030. The Clean Power 2030 target is however defined broadly to include capacity that is installed, under construction, or committed[1]
    - Rising development costs are creating increasing challenges for offshore wind deployment. The priority now is ensuring that the uncontracted project pipeline remains viable and that the UK continues to attract investment into the offshore wind sector
- **On the current trajectory, the 2031 - 2035 period in the UK would be expected to rely more heavily on LNG imports**, which lends to an increase in the emissions burden, even for LNG sourced from Norway (see NSTA 2024 UK gas supply and emissions chart)

Source for two charts above: NSTA, 2024 Emissions intensity of the producing natural gas)

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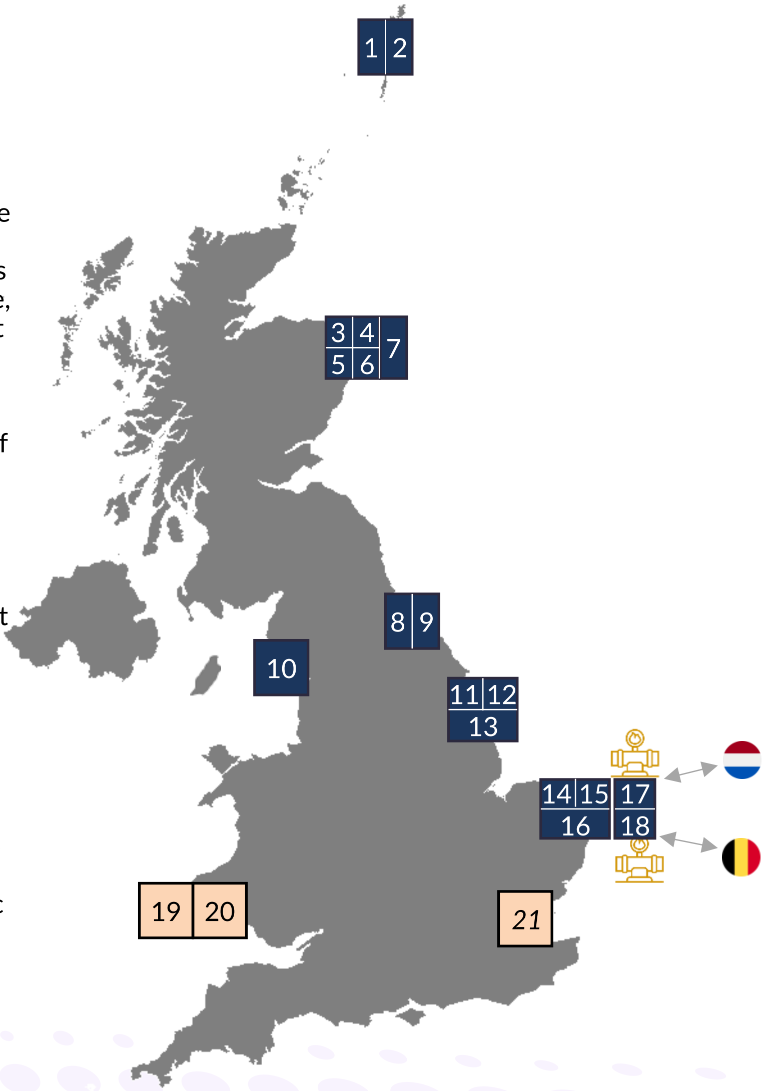
[1]NSTA 2024 Emissions intensity of producing gas factsheet, published September 2025
[2] Defined as "projects that have secured a CfD but not yet become fully operational" in the language of the Clean Power 2030 report

Infrastructure overview

UKCS Gas & LNG Terminals

The UK has 18 active gas terminals, alongside three LNG facilities and two interconnectors, facilitating gas trade between the UK and wider Europe

- The UK's gas terminals are largely clustered on the East Coast. St Fergus, near Peterhead, and Bacton, in Norfolk, each have five terminals, with the latter site including two export facilities to Continental Europe (Balgzand Bacton Line (BBL) and Zeebrugge). There are three terminals at Dimlington/Easington, in Yorkshire, two terminals on Shetland and two at Teesside
- LNG import facilities are located in southwest Wales as well as the Isle of Grain facility in Kent, which is Europe's largest facility
- Several sites are evaluating the potential in the energy transition - largely CCS and hydrogen - to protect jobs and sustain industrial and locational advantages
- Due to proximity and interconnectivity of some terminal sites across the UK, there could be opportunities in the future for rationalisation at the terminal sites to deliver greater efficiencies, lower operating costs and sustain economic operations as throughput volumes drop



Type & Characteristics

Shetland — *2 terminals*
Shetland Gas Plant (TotalEnergies)
Sullom Voe Terminal (BP & EnQuest)
1 | 2

St Fergus — *5 terminals*
St Fergus SAGE (Ancala)
St Fergus FUKA (NSMP)
St Fergus SEGAL (Shell)
National Gas Terminal
Gassco Vesterled**
3 | 4 | 5 | 6 | 7

Teesside — *2 terminals*
Teesside CATS (Kellas)
Teesside Gas Processing Plant (NSMP)
8 | 9

Barrow
Rampside Terminal – Barrow (Spirit Energy)
10

Dimlington/Easington — *3 terminals*
Dimlington (Perenco)
Dimlington (Centrica)
Gassco Langeled**
11 | 12 | 13

Bacton — *3 terminals*
Bacton (Perenco)
Bacton (Shell)
National Gas Terminal
14 | 15 | 16

Bacton Interconnector — *2 terminals*
Bacton-Balgzand Line (BBL) interconnector
Zebrugge interconnector
17 | 18

South Hook LNG
Storage Capacity: 5 x 155,000 m³ tanks
Exclusively Qatari supply between 2010-2018, after which US imports received. QE majority owned with E&P partners
19

Dragon LNG
Storage capacity: 2 x 160,000 m³ tanks
Serves up to 96 vessels per year. Operational since 2009. 10MW solar on-site
20

Isle of Grain
Storage capacity: 1,000,000 m³
Europe's largest site, >600 acres, which can process LNG from any source & direct NTS access. H2 and NH3 potential
21

Terminal | LNG Terminal | Interconnector

*Source: National Gas. **Norway piped gas terminals
N.B. Theddlethorpe and Point of Ayr Gas Terminals excluded as ceased

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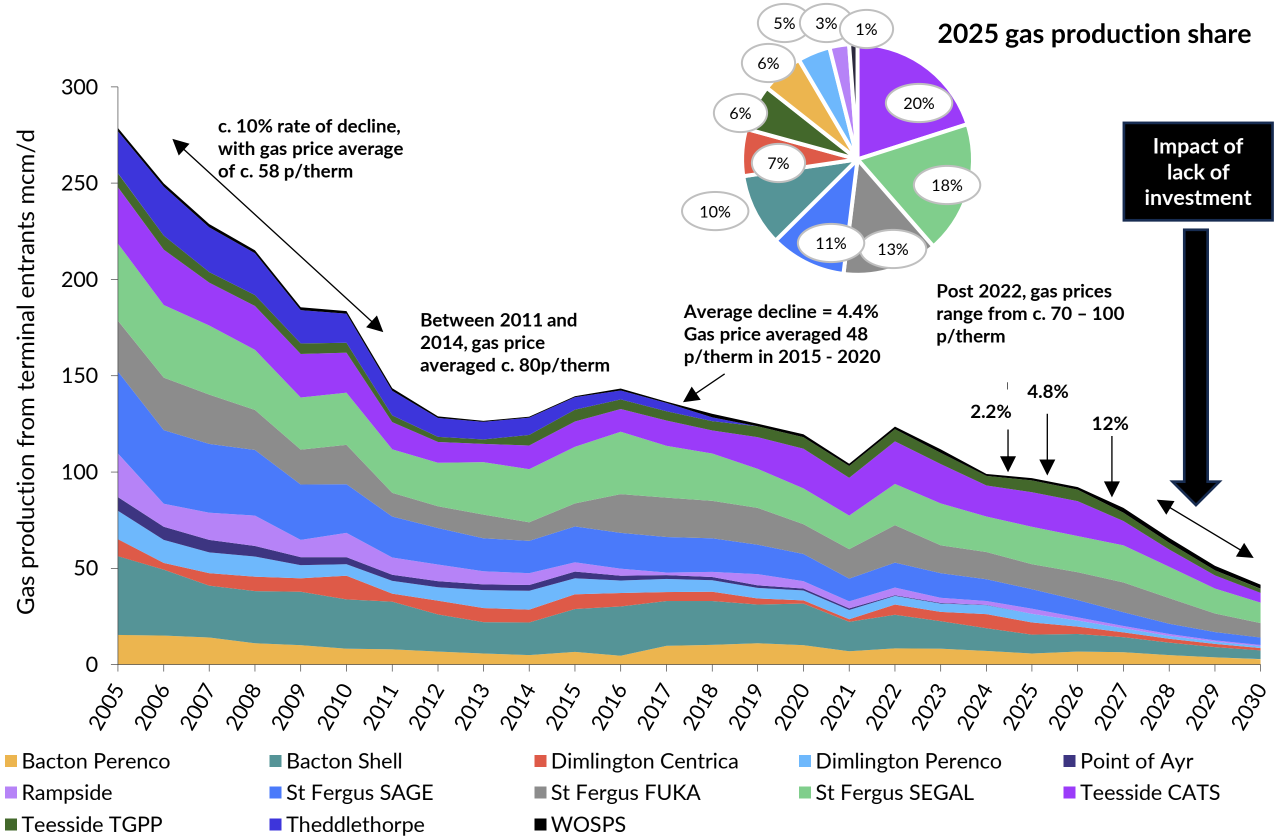
UKCS gas production to processing terminals

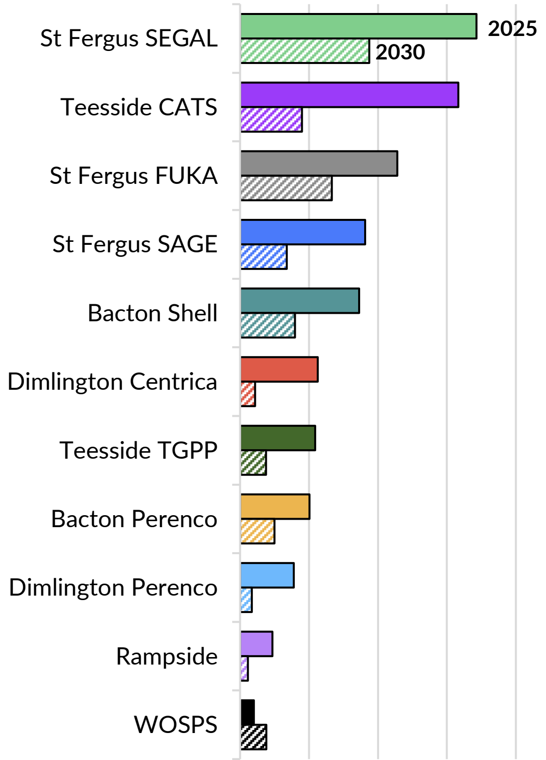
Maintaining domestic production supports UK jobs ,offshore, onshore and at terminals. Between 2020 and 2024, the UKCS supplied 43% of the UK five-year gross UK annual gas supply[1]. Energy policy is driving a faster decline of production

Historical production of entrants to UK gas terminals and current production outlook to 2030*



Note: The production chart includes production throughput from Norway hubs. The chart does not include the two Gassco terminals which receive only Norway production throughput.

2025 & 2030 production comparison



- UK gas production peaked in 2001, at c. 339 mcm/d. At the time it supported all of UK energy demand
- Up to 2012, gas production was in steep decline. Favourable commodity prices, application of new technologies and supportive fiscal terms drove capital investment. The decline was arrested
- Gas throughputs to the UK terminals is forecast to reduce significantly by 2030, under current conditions
- Gas is produced from three generic reservoir types;
  - 'Dry' gas from the Southern North Sea basin, with low levels of associated condensate
  - 'Wet' gas with associated condensate and natural gas liquids (NGLs)
  - Associated gas, produced in conjunction with oil
- Since 2022, wholesale gas prices have dropped to a 'new normal' of around 80 p/therm. This is favourable for continued investment in UK assets, should the headline tax rate return to a more business-friendly rate of 40% from the current 78%
- Gas prices fluctuate due to global LNG market supply and demand, with European weather conditions also affecting European gas pricing, causing price spikes during cold snaps
- While production enters a steeper decline between 2026 and 2030, this is a function of lack of investment. This decline could be arrested, as occurred between 2011 and 2020, should fiscal and regulatory conditions encourage investment

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Source: Westwood Energy Atlas, [1]DESNZ analysis of DESNZ (2025) 'Energy Trends: UK gas'
**Historic and forecast production split of CATS pipeline gas between Teesside CATS and TGPP is based on 2025 production share.*

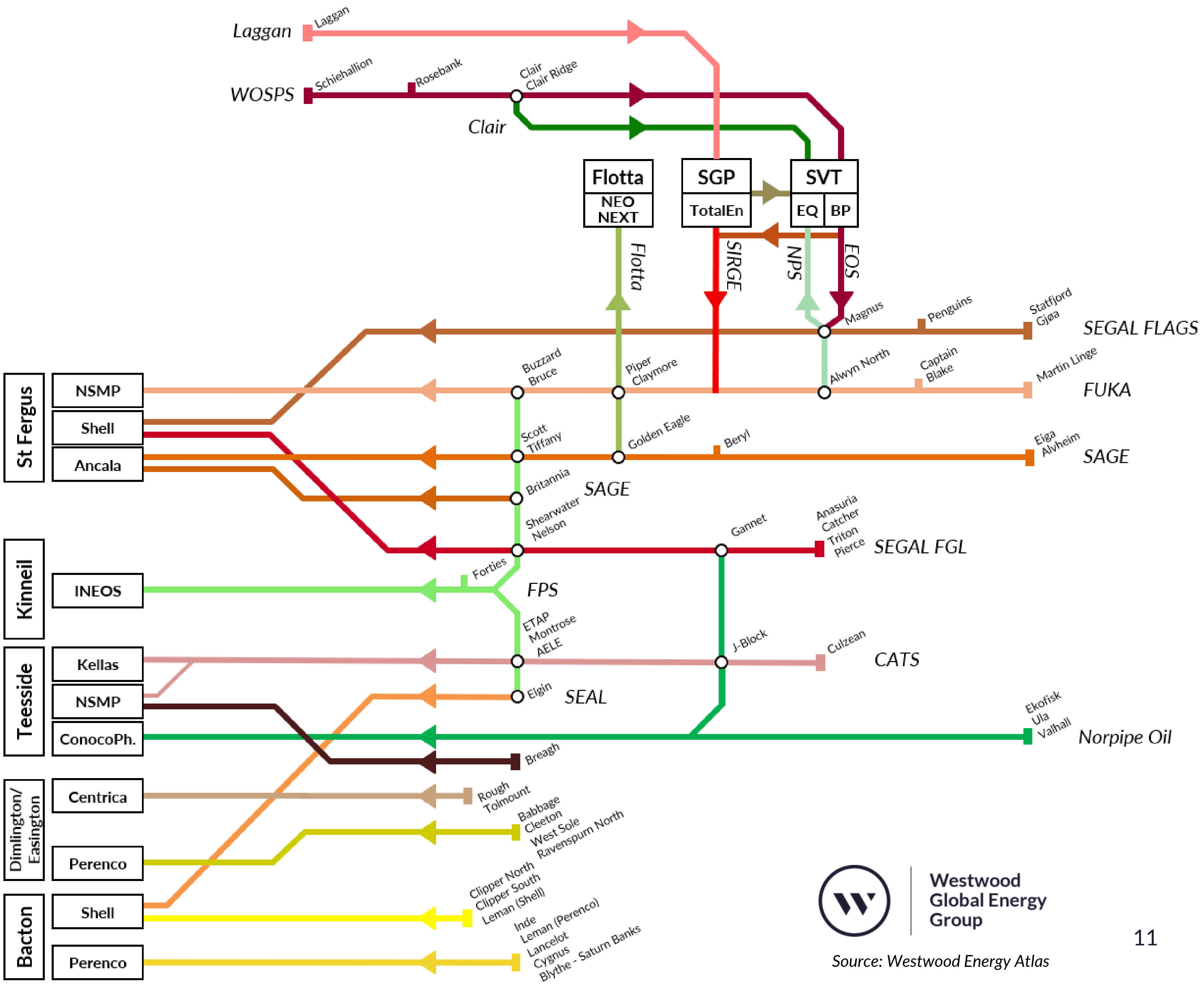
Interconnectivity tube map

Liquids Pipelines

- Clair
- Flotta
- FPS (Forties Pipeline System)
- Norpipe Oil
- NPS (Ninian Pipeline System)
- SGP to SVT condensate

Gas Pipelines

- Bacton, Shell – various
- Bacton, Perenco – various
- Breagh
- CATS (Central Area Transmission System)
- Dimlington, Perenco - various
- Easington, Centrica - various
- EOS (East of Shetland pipeline)
- FUKA (Frigg UK Association)
- Laggan
- SAGE (Scottish Area Gas Evacuation)
- SEAL (Shearwater and Elgin Area Line)
- SEGAL FGL ((Shell Esso Gas and Associated Liquids) Fulmar Gas Line)
- SEGAL FLAGS (Far North Liquids and Associated Gas System)
- SIRGE (Shetland Islands Regional Gas Export)
- WOSPS (West of Shetlands Pipeline System)



Note: Graphic does not accurately represent geographical relationships between hubs or pipeline routes, instead it shows interconnectivity and relational significance of pipelines and hubs.
For simplicity, extracted liquids export from St Fergus (to Kinneil and Fife NGL), and from Bacton to Harwich, are not shown. More detail can be found on pages 35 and 36.
Hubs expected to cease production before 2028 and pipelines with no input from UK fields (e.g. Langeled) are excluded from this diagram.
Diagram shows terminal and operator as well as processing hub, individual fields are not labelled.
TotalEn = TotalEnergies, EQ = EnQuest, ConocoPh. = ConocoPhillips
Information correct at 1 February 2026.

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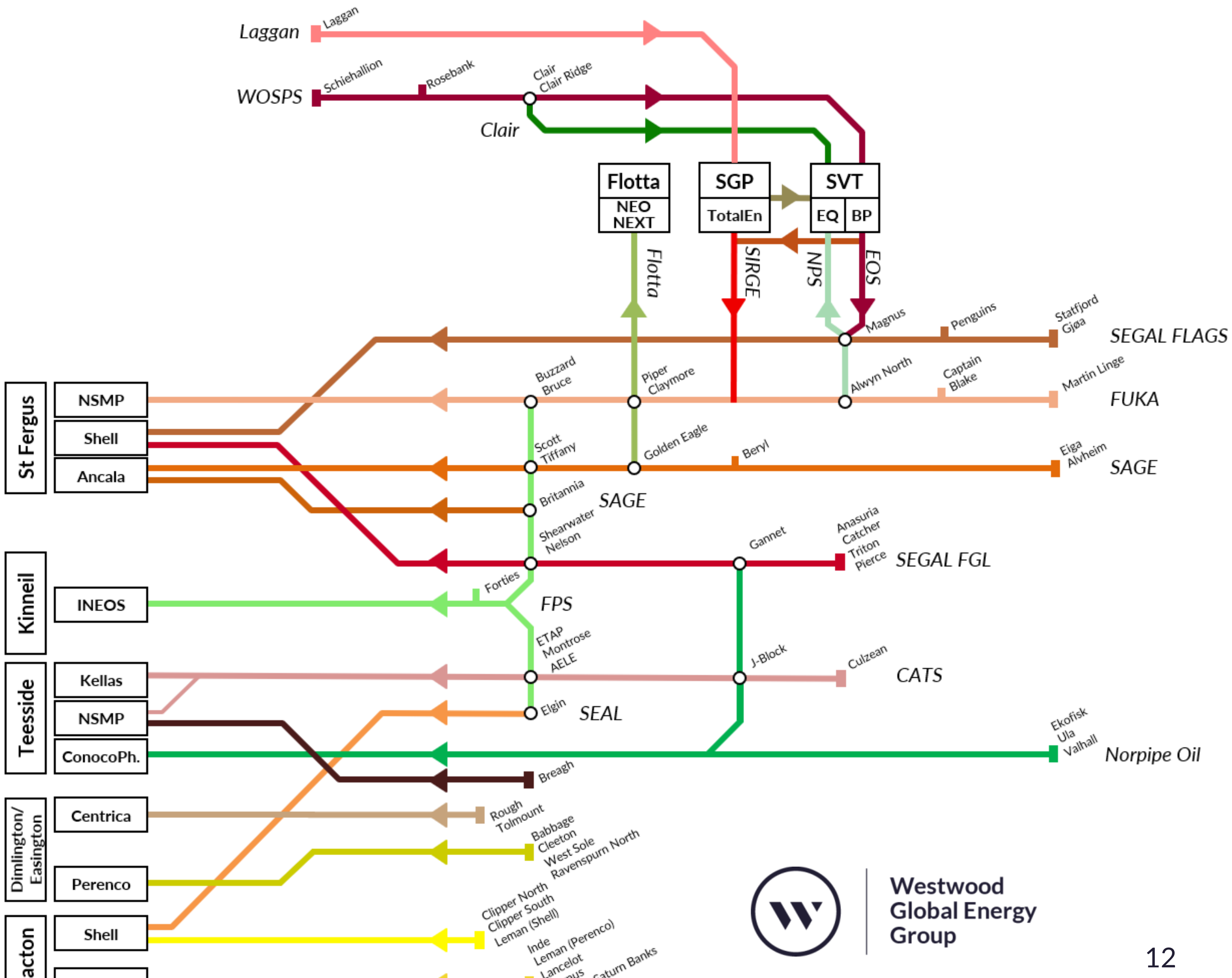
Source: Westwood Energy Atlas

Interconnectivity tube map

Liquids and gas export routes are intrinsically linked. Changes to one export route can impact many other export routes. Collapse of one pipeline route can impact other systems

- Outside of the SNS which produces dry gas, most hubs have two export routes – one for liquids and one for gas
- The interdependency means that if one system becomes uneconomic, it could lead to a domino effect and forced cessation of other systems
- Because gas production outside the SNS is reliant on both gas and liquids infrastructure, in order to maintain resilience in the gas infrastructure, it is important to also support the needs of the oil infrastructure
- If liquids hubs cease prematurely, it could also result in the early cessation of gas production and increase the strain on the related infrastructure
- There is added interconnectivity considerations for condensate and NGLs:
    - St Fergus terminals rely on either Fife Natural Gas Liquids plant (FNGL) or Kinneil for processing of extracted liquids. Fife Ethelyne Plant (FEP) had been an alternative route, but in November 2025 ExxonMobil announced plans to close FEP, with the loss of c. 400 jobs
    - Condensate from the Bacton terminals has historically been processed at Harwich refinery, however, in August 2025 Haltermann Carless announced the closure of the condensate unit, meaning an alternative route must be found
- Reduced flow rates could see terminal and refinery economics becoming more marginal. In 2018, Theddlethorpe Terminal ceased operations, resulting in the premature cessation of 22 SNS gas fields
- Safeguarding domestic production and maintaining flow rates through terminals ensures resilient infrastructure capacity by keeping interconnected pipeline and terminal systems operational



Source: Westwood Energy Atlas

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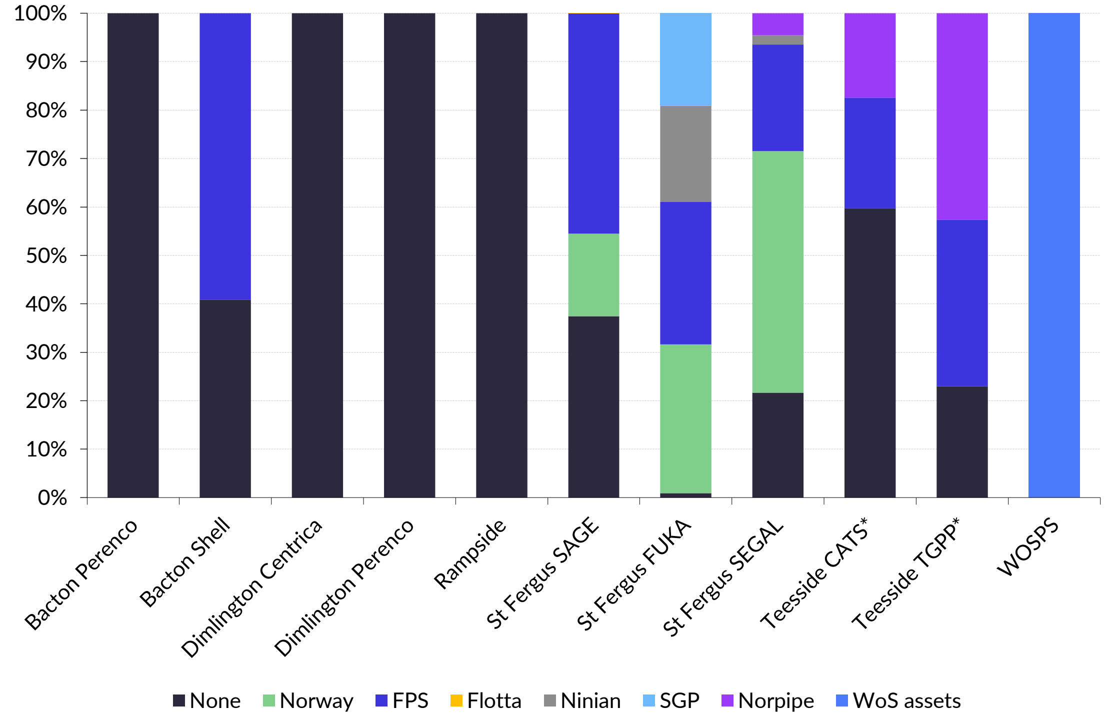
Interdependency of major gas pipelines

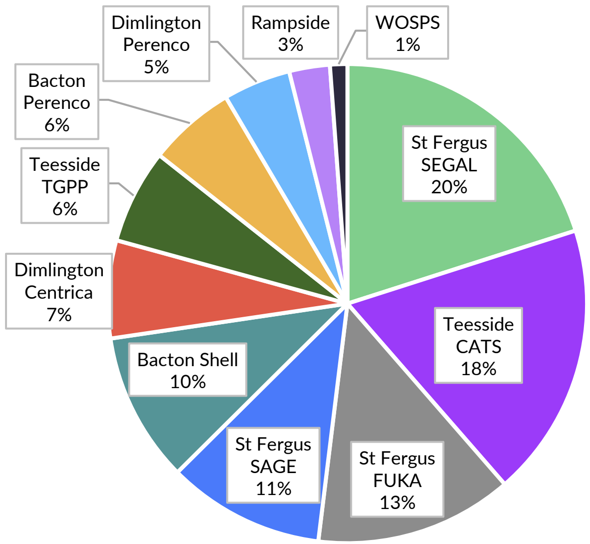
75% of UK gas production is processed at the St Fergus and Teesside terminals. These systems rely on the parallel operation of their associated liquids pipeline infrastructures and terminals

% contribution of gas throughput in 2025
Field entrants which rely on other pipeline systems for export



Note: Flotta contribution to SAGE pipeline is too small to be visible on chart
**Due to the information being commercially sensitive – it is not publicised which fields in the CATS pipeline system use CATS for gas processing vs TGPP. In 2025, CATS terminal processed Culzean gas and 62% of the remaining CATS system gas. Future dependence for the Teesside plants may vary based on commercial arrangements.*

2025 gas production share by terminal



- Some UK gas terminals receive gas from fields that do not have interdependency on other pipeline systems. These hubs[1] either do not require a separate liquids export route, e.g. the ‘dry’ gas fields in the SNS, or the oil and liquids are offloaded via tankers. These are marked in the bar chart as ‘None’
- Many CNS and NNS assets export gas and liquids via different pipeline systems and terminals. Tariffs or cost-share arrangements must cover the costs needed to operate and maintain the pipeline and terminal infrastructure. If one infrastructure system becomes uneconomic, it will force the closure of hub entrants, impacting the economics of the other export route
- Six gas terminals receive gas from entrants also reliant on the Forties Pipeline System for liquids export. Three of these terminals also receive gas from entrants reliant on Norpipe.
- Associated gas from WoS assets is exported via the WOSPS[2] but are reliant on economic production of the oil and gas production hubs (e.g. Clair and Schiehallion). From 2026, WOSPS gas can route to FLAGS via Magnus or to FUKA via SIRGE

[1] A hub is the central offshore processing facility for one or more fields, which then exports oil/liquids/gas via different export routes
[2] West of Shetlands Pipeline System

Source: Westwood Energy Atlas

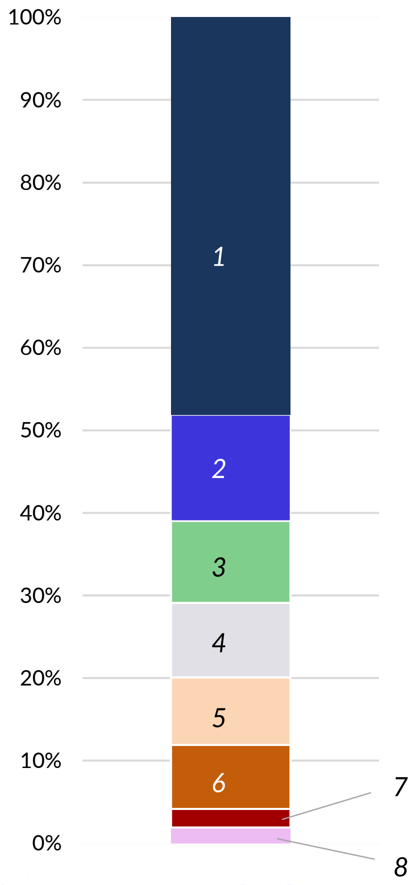
Overview of hydrocarbon gas storage

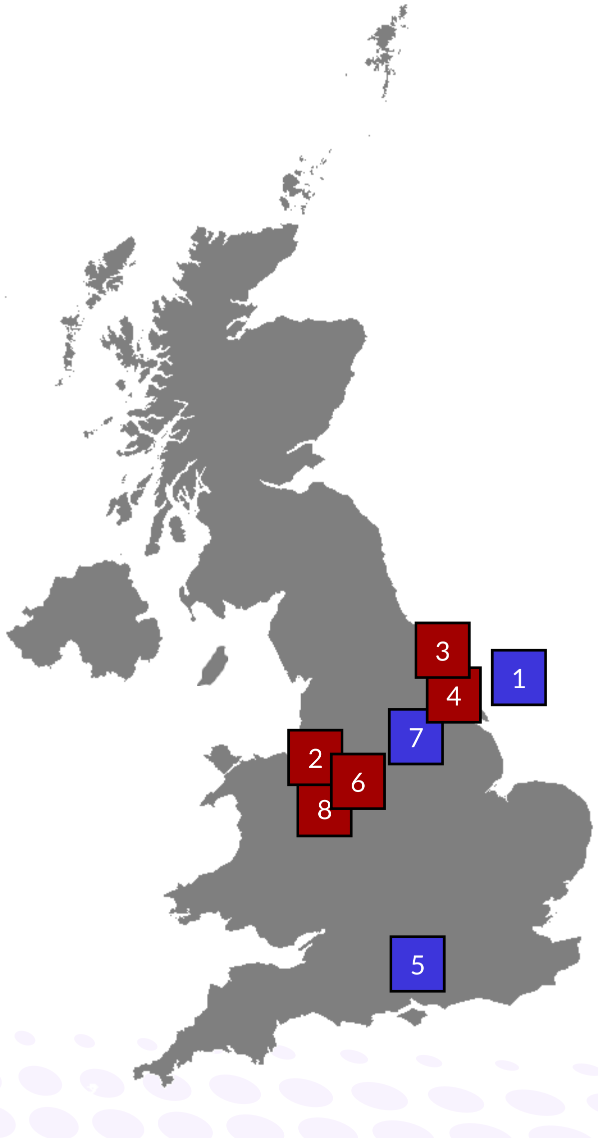
UK Gas Storage

The UK has total gas storage capacity totalling 3.1 bcm across 8 sites, the largest of which is the Centrica Storage Rough facility (48% of total capacity) off the East Coast of England

UK Gas Storage Facilities by Size

Percentage of UK Estimated Working Gas Volume





Type & Characteristics

Rough — *Since 2022**
Est. working gas volume: 1.5 bcm
Approx. max production rate: 11 mcm/d
Approx. max injection rate: 9 mcm/d
Withdrawal duration: >115 days
1

Stublach — Since 2014
Est. working gas volume: 0.4 bcm
Approx. max production rate: 30 mcm/d
Approx. max injection rate: 30 mcm/d
Withdrawal duration: 13 days
2

Hornsea (Atwick) — Since 1979
Est. working gas volume: 0.3 bcm
Approx. max production rate: 12 mcm/d
Approx. max injection rate: 3 mcm/d
Withdrawal duration: 26 days
3

Aldbrough — Since 2009
Est. working gas volume: 0.3 bcm
Approx. max production rate: 26 mcm/d
Approx. max injection rate: 26 mcm/d
Withdrawal duration: 10 days
4

Humbly Grove — *Since 2005*
Est. working gas volume: 0.3 bcm
Approx. max production rate: 7 mcm/d
Approx. max injection rate: 8 mcm/d
Withdrawal duration: 34 days
5

Holford — *Since 2011*
Est. working gas volume: 0.3 bcm
Approx. max production rate: 22 mcm/d
Approx. max injection rate: 26 mcm/d
Withdrawal duration: 19 days
6

Hatfield Moor — *Since 2000*
Est. working gas volume: 0.1 bcm
Approx. max production rate: 2 mcm/d
Approx. max injection rate: 2 mcm/d
Withdrawal duration: 60 days
7

Hill Top Farm — *Since 2011*
Est. working gas volume: 0.1 bcm
Approx. max production rate: 13 mcm/d
Approx. max injection rate: 13 mcm/d
Withdrawal duration: 5 days
8

Depleted oil & gas field | Salt cavern

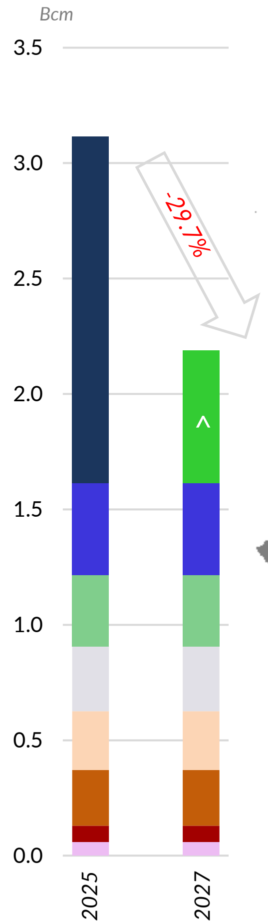
- The UK has eight active gas storage facilities of varying size, duration (the time a facility takes to deplete from full at the maximum withdrawal rate, measured in days) and form
- The largest is Centrica Energy Storage's (CES) Rough facility, comprising five fixed platforms (3 NUIs) and a depleted hydrocarbon reservoir capable of storing 1.5 bcm, with a duration of around 115 days. Initially opened in 1975, the facility ceased in 2017 before re-opening for storage operations in 2022. The site has an aging well stock, the cause for the initial shutdown, cost of remediation was reported to be c. £2 billion
- Two other depleted hydrocarbon reservoirs, Humbly Grove and Hatfield, provide a further 8.2% and 2.2% of total gas storage, respectively
- A further 5 gas storage facilities take the form of salt caverns and are located across Cheshire and Lancashire. These facilities are man-made via solution mining, a process where rock salt deposits are drilled and injected with high-pressure water to dissolve the salt and create an airtight space
- **Total storage capacity equates to c. 16 days of national gas demand (annual average), or only 10 days when based on January 2025 demand[1]**
- Total EU gas storage capacity is c. 102 bcm[2]

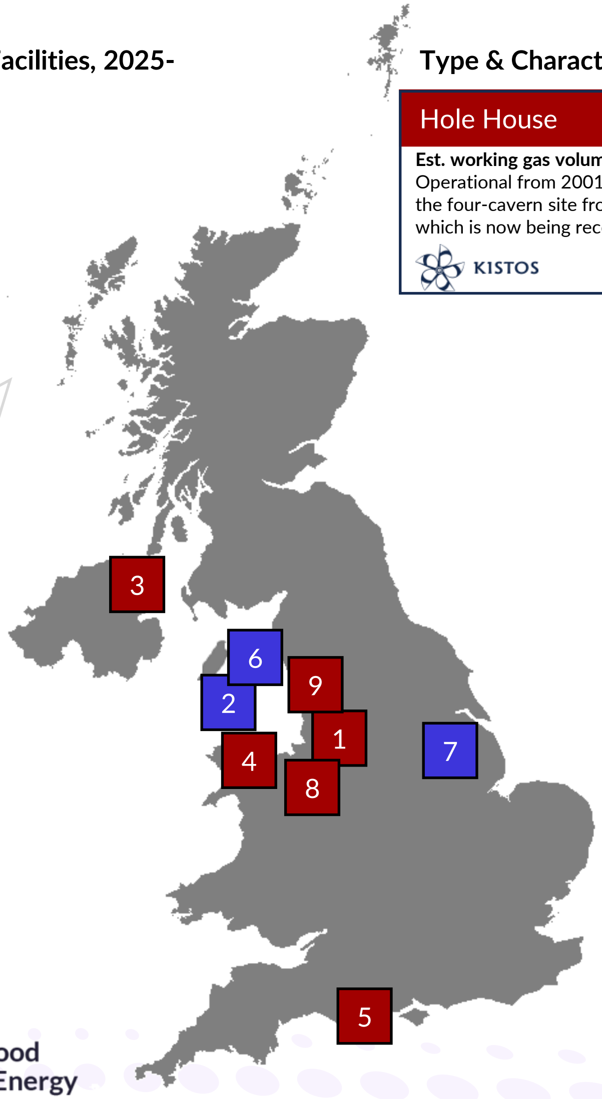
Source: Westwood Energy, company investor reports and Ofgem
[1] Based on 2025 daily average demand reported by National Gas, differs from DESNZ consultation document due to different time span used to calculate average
[2] European Commission estimate, October 2025
** Rough restarted operations in 2022, having previously ceased in 2017*

UK Gas Storage - Outlook

Several sites originally planned for gas storage are now being considered for hydrogen but may revert to methane. Only Hole House has received FID, meaning total capacity could drop by c. 30% in 2027

UK Gas Storage Facilities, 2025-





Type & Characteristics

Hole House — *Sanctioned* — 1

Est. working gas volume: 0.5-0.6 bcm
Operational from 2001-18, Kistos acquired the four-cavern site from EDF in 2024, which is now being recommissioned.
KISTOS

Bains — *FID 2027* — 2

Est. working gas volume: 1.4 bcm
Field CoP in 2017. NSTA storage licence GS007 award in 2023. FID expected in 2027 & first gas in 2030. CAPEX estimate £830m.
dCarbonX snam

Islandmagee — *Proposed* — 3

Est. working gas volume: 0.5 bcm
2012 storage licence award. 7 caverns. FEED complete but on pause due to 2024 legal challenge. CAPEX c. £400m. H2 potential.
Harland & Wolff

Gateway — *Proposed* — 4

Est. working gas volume: 0.8 bcm
Awarded storage licence GS008 by NSTA in August 2025. Previously progressed to FID as gas storage project, now assessing for H2.
dCarbonX snam

Portland Port — *Superseded* — 5

Est. working gas volume: 1 bcm
Part of Solent Cluster. Previously gained approval but reassessed for H2. In 2025, strategic focus shifted to South Dorset site.
UKOG

MESH — *FID TBC* — 6

Est. working gas volume: 1.4 bcm
Repurposing existing gas infrastructure and depleted gas field. 2030 start up target. Also plans for H2 in salt caverns & wind power.
EnergyPathways

Saltfleetby — *Proposed* — 7

Est. working gas volume: TBC
Largest UK onshore gas field, producing since 1999. MoU signed with Trafigura to evaluate mid/long term gas storage.
ANGUS ENERGY

KGSP — *FID 2026* — 8

Est. working gas volume: 0.5 bcm
Nationally Significant Infrastructure Project, consented in 2017. 19 caverns on Holford Brinefield, supporting HyNet. FID target 2026.
INEOS Inovyn storengy ENGIE

Preesall — *Proposed* — 9

Est. working gas volume: 0.6 bcm
Nationally Significant Infrastructure Project comprising 19 mines, consented in 2015. Designed as a 'fast-cycle' facility.
halite NPL GROUP

Depleted oil & gas field | Salt cavern | ^Hole House estimate

- CES' licence for Rough Gas is temporary, and the facility's economics remain challenged absent of robust assurances from the Treasury about the level of support that will be made available. Westwood's modelling and wider consultation with industry sources indicate that there is a strong probability that Rough storage operations could cease within 12 months
- Westwood has identified an additional nine projects that have the potential to alleviate the challenge associated with losing 48.2% of domestic gas storage capacity[1]. Total storage capacity of these proposed sites exceeds 6.7 bcm, more than double the currently active storage capacity and equivalent to c. 34 days of national gas demand[2]
- However, of those, only Kistos' Hole House facility has been sanctioned, in September 2025. However, a decision at Bains, MESH and KGSP could be reached in the coming years
- In the scenario where Hole House opens and Rough closes, the UK loses 29.7% of total capacity within as little as 12 months

[1]*Includes hydrogen-focused sites, which could revert to methane*
[2]*Based on 2025 daily average demand reported by National Gas*
Source: Company investor reports

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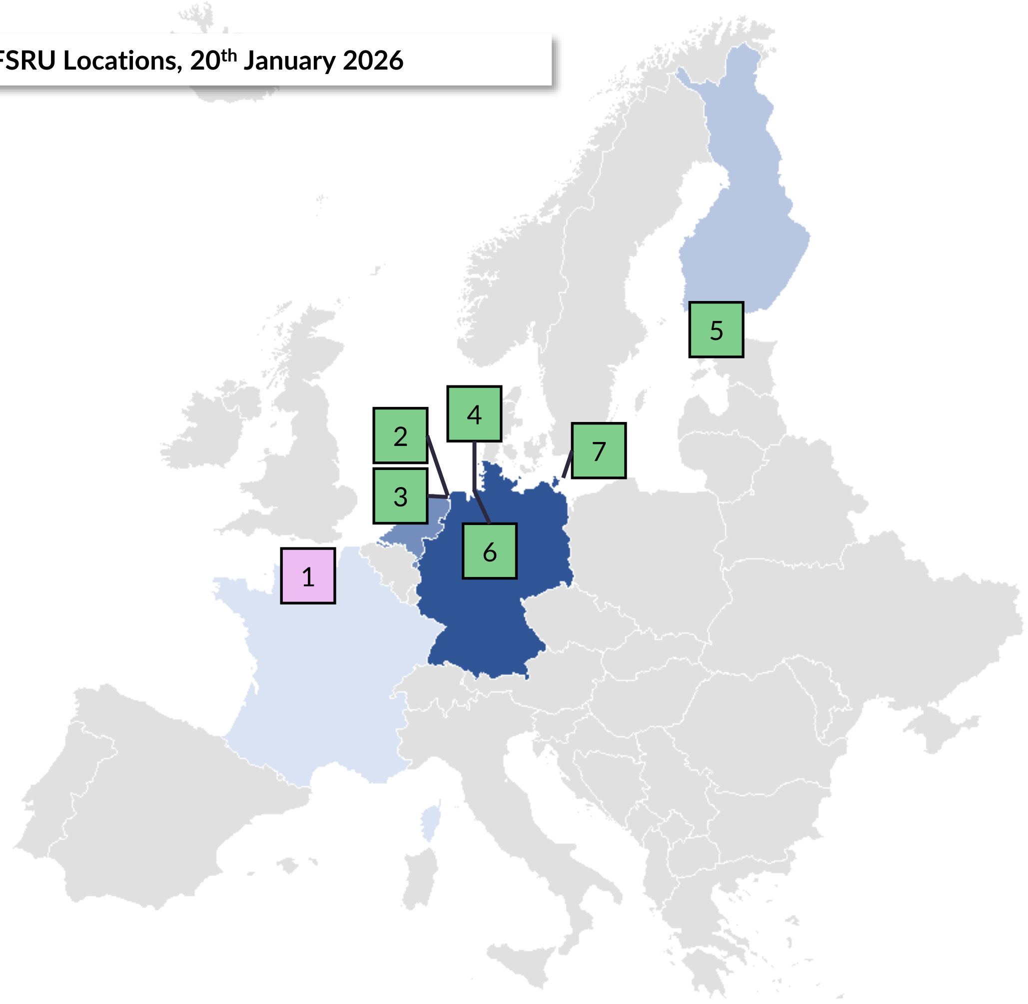
NW European FSRUs

Westwood is currently tracking 50 active FSRU globally. 7 of those are currently located in NW Europe, providing a combined annual processing capacity of >31 million tonnes of LNG

FSRU Locations, 20th January 2026



Status & Capacities

1. Cape Ann (Available)
Gas throughput capacity: 21 mcm/d
LNG throughput capacity: 6,200,000 TPA
Gross liquid storage capacity: 0.15 mcm
Fixed lease expiry: -

2. Eemshaven LNG (Operational)
Gas throughput capacity: 17 mcm/d
LNG throughput capacity: -
Gross liquid storage capacity: 0.03 mcm
Fixed lease expiry: Q3 2027

3. Energos Igloo (Operational)
Gas throughput capacity: -
LNG throughput capacity: 5,400,000 TPA
Gross liquid storage capacity: 0.17 mcm
Fixed lease expiry: Q3 2027

4. Excelsior FSRU (Operational)
Gas throughput capacity: 14 mcm/d
LNG throughput capacity: 4,100,000 TPA
Gross liquid storage capacity: 0.14 mcm
Fixed lease expiry: Q4 2028

5. Exemplar (Operational)
Gas throughput capacity: 14 mcm/d
LNG throughput capacity: 4,100,000 TPA
Gross liquid storage capacity: 0.15 mcm
Fixed lease expiry: Q4 2032

6. Hoegh Esperanza (Operational)
Gas throughput capacity: 21 mcm/d
LNG throughput capacity: 6,000,000 TPA
Gross liquid storage capacity: 0.17 mcm
Fixed lease expiry: Q3 2032

7. Neptune FSRU (Operational)
Gas throughput capacity: 21 mcm/d
LNG throughput capacity: 5,750,000 TPA
Gross liquid storage capacity: 0.15 mcm
Fixed lease expiry: Q4 2029

Available | Operational

Note: Liquid storage volumes are compressed and therefore not directly comparable with gas storage volumes

- There are currently seven Floating Storage and Regasification Units (FSRUs) active across Europe; all but one is contracted. These facilities have a combined gas throughput capacity of 109 mcm/d, over 31 million tonnes per annum (TPA) of cumulative LNG throughput capacity, and c. 1 mcm of gross liquid storage capacity. A further four FSRUs are due to arrive in NW Europe before 2030, including the Energos Force, a 5.5 million TPA unit due at Hanseatic Energy Hub
- The wider FSRU market is seeing strong growth, driven by rising global LNG demand. Westwood is tracking US$2.1 billion of EPC awards for newbuild and converted units out to 2028. A further 11 units are expected to be redeployed in the same period, underscoring FSRUs' flexibility in balancing supply & demand. One recent example is the Energos Winter, which relocated to Egypt's Damietta terminal after operating for less than 10 months at Brazil's Santa Catarina terminal
- While an FSRU increases LNG import capacity, it does not support domestic production; as a result, it does not contribute to the resilience of existing infrastructure in the way sustained UK production does and is more exposed to global competition for supply

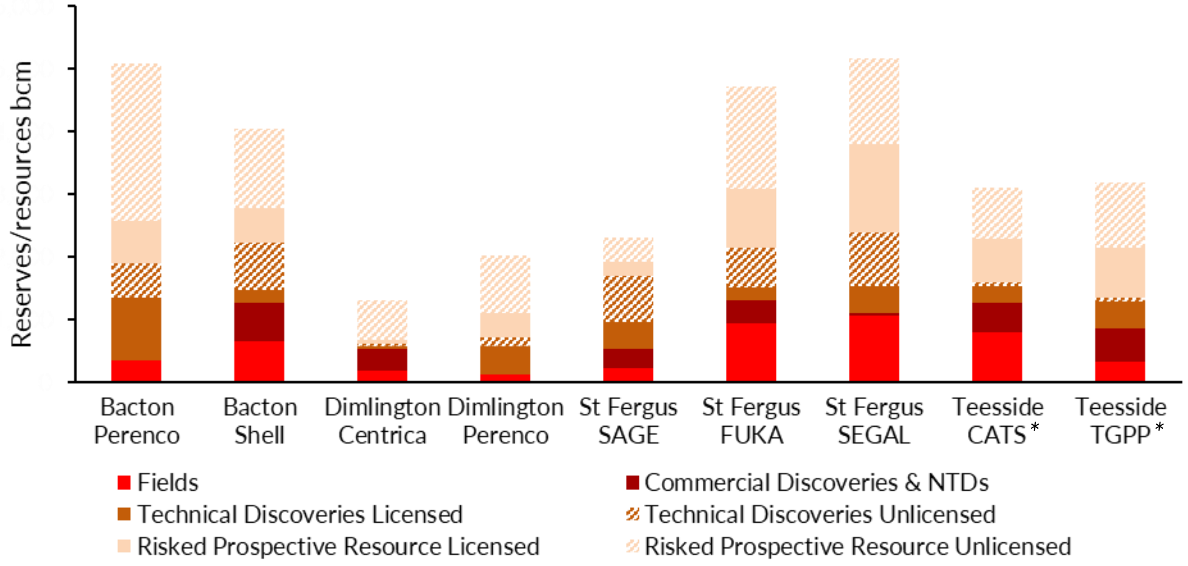
Source: Westwood Energy PlatformLogix

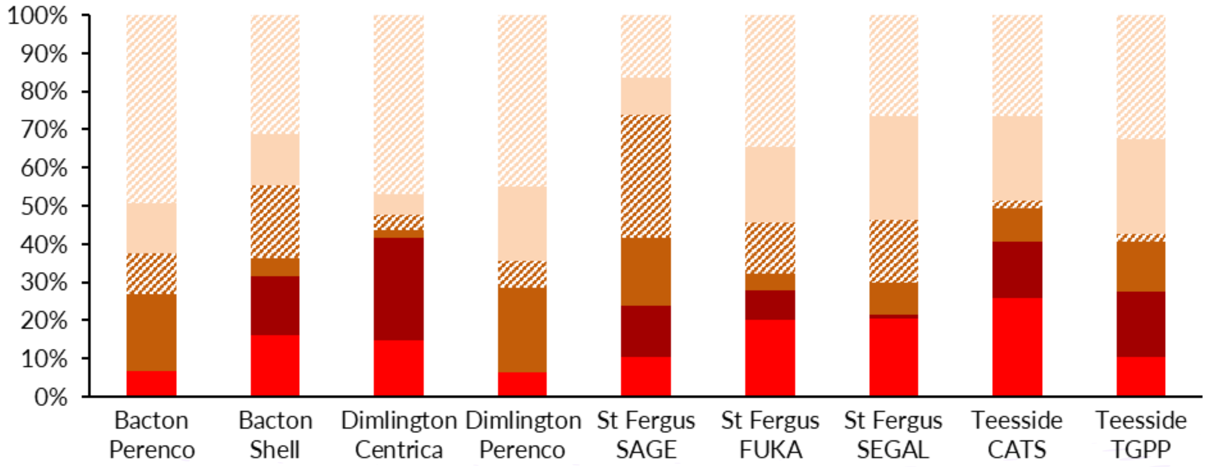
Upside opportunities around major UKCS gas infrastructure routes

Gas Pipeline System Upside

Significant upside surrounds key pipeline systems, much of it is in unlicenced acreage or requires improved market conditions to be commercialised. While production is declining, the rate of this is driven by policy not geology

- Only 1 terminal has less than a third of reserves & resource upside in unlicenced acreage
- No single system has more than 17% of total UKCS upside potential, demonstrating the diversity of the UKCS pipeline network
- Every system has a mix of reserves/resource maturity, with near-term and longer-term opportunities present for every system
- Upside is broadly spread geographically, with systems in each basin showing material contributions to UKCS-wide gas potential
- Unlicenced prospective resources represent an important share of basin potential
- Improved market conditions are required to commercialise technical discoveries. Similarly, increased exploration rates are required to realise upside potential from prospective resources





Notes:

Due to optionality from 2026 onwards, reserves and resource upside for WOSPS entrants is split evenly between St Fergus SEGAL and St Fergus FUKA.

** In 2025, the CATS processing plant processed 80% of CATS pipeline gas, with TGPP processing the remaining 20%. For reserves, Westwood has assumed the same 80:20 split, however, future throughput for the Teesside plants may vary based on commercial arrangements. For resource upside a 50:50 split has been assumed as operators have optionality for where gas is processed.*

Field reserves does not include potential upside from as yet unsanctioned investment such as infill drilling, meaning some upside assessments may be conservative for in field upside.

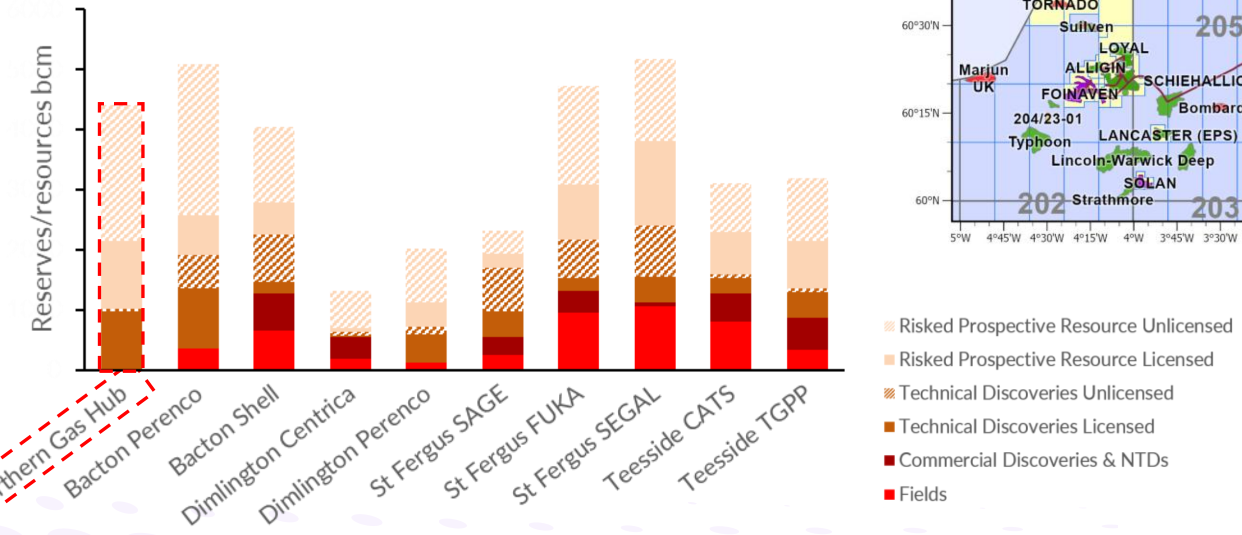
Reserve/resource volumes redacted.

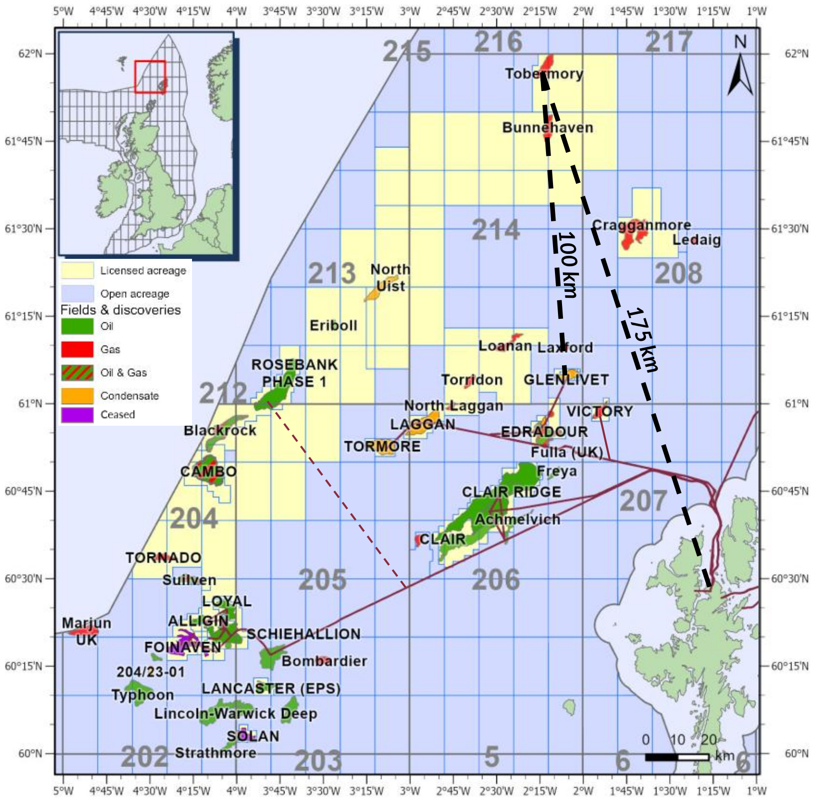
Source: Westwood Energy Atlas

West of Shetland – Potential future gas hub

The Northern Gas Hub is a remote cluster of unsanctioned discoveries and prospects that offer substantial potential upside but are uneconomic at current volumes. Further discoveries in this area could unlock this resource

- To demonstrate the considerable resource potential within the Northern Gas Hub, it ranks 4th in terms of total resources, and total licenced resources, when compared to major UK gas infrastructure
- There is interest in the area - much of the acreage was awarded in the 33rd Round and Ithaca Energy recently farmed-in to two licences in the area
- Could extend longevity of the Shetland Gas Plant - the UKs newest onshore gas processing facility, sanctioned in 2010 and operational in 2016
- Requires more attractive fiscal terms to encourage investment in exploration (on licenced acreage) and possible future development
- Based on 2025 LNG import average, the Northern Gas Hub could provide the equivalent of c. 975 days of LNG supply over the duration of its field life[1]
- This could save c. 12 million tonnes CO_2, based on the emissions intensity of LNG and WoS gas production, equivalent to a 76% saving on emissions[2]





[1] Based on 75% of recoverable resources in discoveries, and 35% of licenced risked prospective resources being developed.
[2] Based on average LNG emissions intensity for 2024 and emissions intensity at the Laggan hub. Reserve/resource volumes redacted.

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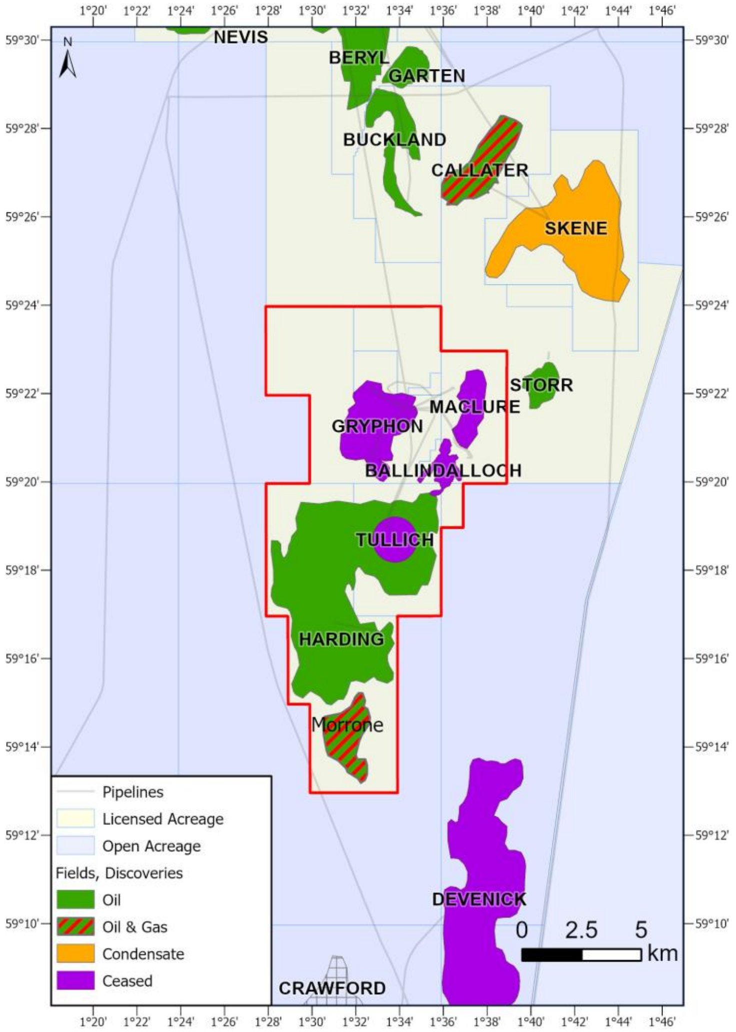
Source: Westwood Energy Atlas

Quad 9 – Undeveloped gas opportunity

Significant gas opportunity overlying five NNS fields

- A significant gas cap straddles the two hubs of Gryphon and Harding in the Quad 9 area
- The Gryphon Area comprised the development of the North and South Gryphon, Maclure, Tullich and Ballindalloch, fields as subsea tie-backs to the Gryphon FPSO
    - The fields were developed to produce oil and associated gas, with oil offloaded via shuttle tankers and gas via the SAGE infrastructure system. Production commenced from Gryphon in 1993, Maclure and Tullich in 2002 and Ballindalloch in 2019
    - Production from the hub ceased on 31 December 2024 and the FPSO left the field in October 2025
- The Harding field is composed of five separate reservoirs and developed using a three-legged, standalone platform, with oil exported via tanker and no gas export route (a portion of the gas was reinjected into the reservoir for pressure support). Harding started production in 1996 and is expected to produce until 2027
    - The Morrone field had been planned for development around 2013, as an extended reach well drilled from Harding, but the development did not progress
- The gas cap straddles the Harding, Gryphon North, Gryphon South, Tullich and Morrone fields. Resources have not been publicised but are considered to be > 29 bcm
- In 2017, the participants in the various fields commenced conceptual studies for a joint gas development, led by Maersk Oil (subsequently acquired by TotalEnergies) and TAQA
    - NSTA were supportive of a collaborative area plan
    - Project stalled at the time due to complexity of commercial agreements across multiple fields



Source: Westwood Energy Atlas

Pensacola – Play opening recent gas discovery

The 2023 Pensacola discovery was considered a play opener at the northern end of the SNS - development could unlock other gas upside in the area

Background and resources

Commercial discoveries:

	Operator	Resources	Discovery year
Pensacola	Adura (formerly Shell)	9.9 bcm	2023 (appraised in 2025)
Crosgan	ONE-Dyas	9.9 bcm (in Zechstein + upside in Carboniferous)	1990 (appraised in 2023 & 2025)

Selected prospects:

	Operator	Resources	Discovery year
Dabinett	Horizon Energy Partners	18.8 bcm (pre-drill)	Undrilled prospect
Bonnie Brae	ONE-Dyas	3.6 bcm (pre-drill)	Undrilled prospect

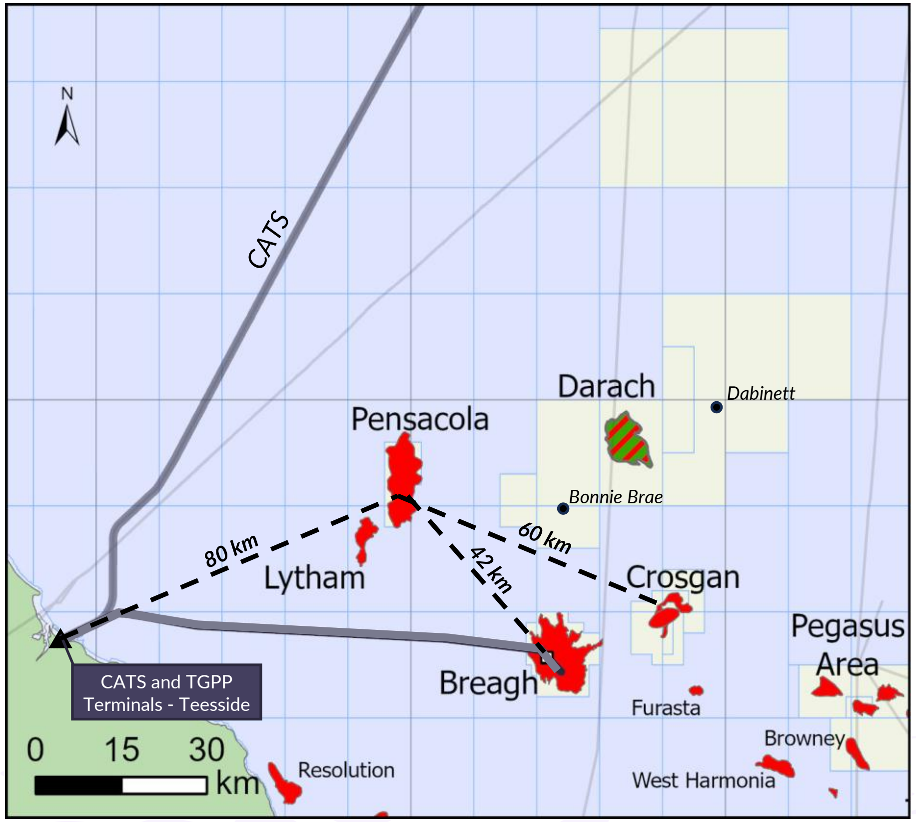
- Pensacola was discovered in 2023 by Shell (now Adura) and an appraisal well successfully completed in 2025
- The nearby licences also include the Crosgan Zechstein commercial discovery. Further upside in technical discoveries seen at Crosgan Carboniferous and Darach. Zechstein prospects identified including Bonnie Brae, Dabinett and others

Challenges

- CO_2 concentration in Pensacola and other Zechstein discoveries adds management challenges:
  - Pipeline corrosion and CO_2 handing capabilities must be considered
  - Current Breagh facilities not designed for Pensacola gas composition and would need modifications
- With the correct fiscal and regulatory landscape in place, Pensacola should be economically viable as a standalone. Once developed, it could unlock further upside in the area

Development pathways

- Standalone pipeline to CATS Terminal
- Standalone pipeline to TGPP
- Tie-back via Breagh to TGPP (would require investment in CO_2 handling facilities at Breagh)



Source: Westwood Energy Atlas

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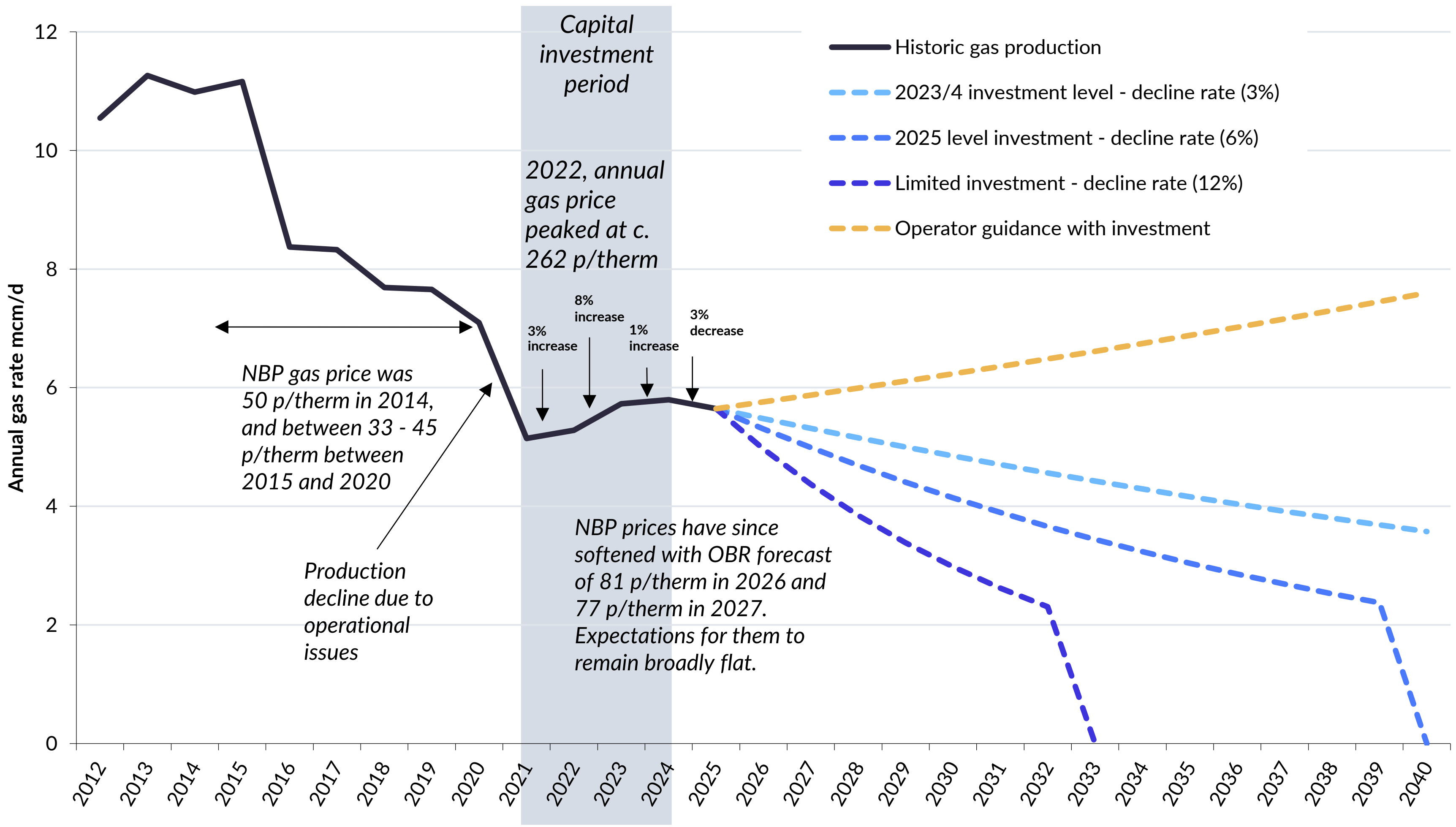
SNS case study – upside in mature fields

The SNS basin is considered super-mature, but companies can still deliver value with the right business conditions. Historically, investment stalled due to less attractive investment landscape



- Westwood has analysed the operated SNS fields of one company, which has international assets in addition to UK assets. The portfolio of fields are mature and export into two onshore gas processing terminals
- Increasing gas prices presented an opportunity to re-invest in the portfolio, executing infill drilling, well intervention and life-extension opportunities, securing approvals for capital allocation ahead of its international oil and gas opportunities
- The result was an uplift in production from these mature fields and capability to maintain production levels
- The headline tax rate of 78% means that capital allocation for projects is now going to overseas opportunities
- The company holds investment opportunities to drill up to 17 wells, with associated resource of 28.3 bcm of gas, which it estimates could lead to a production increase of 2% per annum
- No investment will result in a return to pre-2021 decline rates, significantly reducing operational life of fields and processing terminals
- Progression of investment could sustain the 3% decline rate of 2024/2025 leading to post 2040 production, with an additional 15.6 bcm in resource recovery

Source: Westwood Energy Atlas, OBR and company provided information

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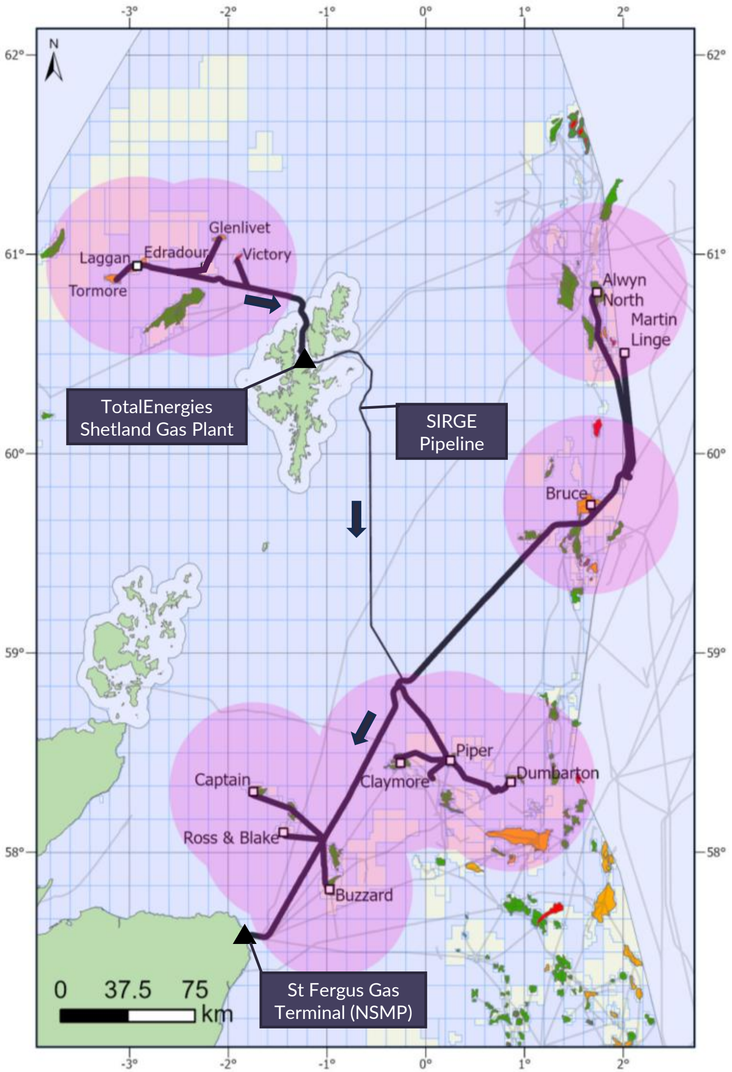
Gas processing terminals and pipeline infrastructure

St Fergus FUKA

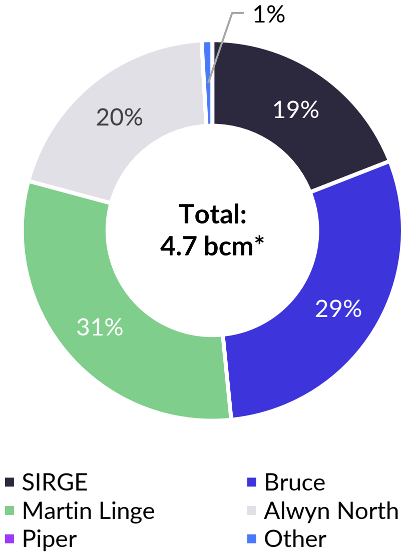
Frigg UK Association (FUKA) system has been operational since 1977 and in 2025 accounted for c. 13% of UK gas throughput

Operator	North Sea Midstream Partners (NSMP)
Terminal	FUKA (Frigg) Terminal, St Fergus
Overview	FUKA pipeline takes gas from entrants in Norway, NNS and CNS. Also, through SIRGE (Shetland Islands Regional Gas Export line) it takes output from the Laggan pipeline (West of Shetland) via the Shetland Gas Plant (SGP). From mid 2026, the WOSPS crossover will be operational. WOSPS can export via SIRGE to FUKA or via Magnus to FLAGS and the St Fergus Shell terminal. Split of gas export volumes has not been disclosed. Extracted liquids from the St Fergus FUKA terminal can be routed to either the Fife NGL plant at Mossmorran (operated by Shell) or the Kinneil plant at Grangemouth (operated by INEOS).

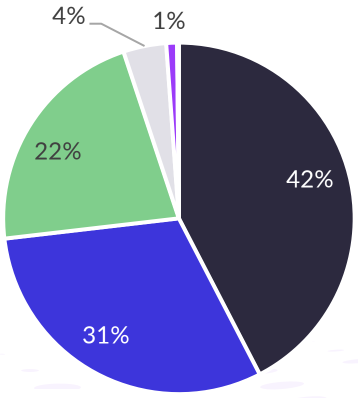
Upside potential summary and risks	
Current outlook	Serica Energy has acquired Laggan Area, which is encouraging for future investment. Routing of some or all of WOSPS gas will provide additional volumes. Victory field commenced production in WoS in 2025, adding c. 4.2 mcm/d.
Upside potential	Infill wells being planned for Martin Linge (Norway) and two exploration wells planned in the area in 2026/2027. Possible tieback of Laphroaig (UK discovery) to Martin Linge. Infill drilling opportunities as Claymore and Piper, Marigold subsea tieback opportunity to Piper. Infill opportunities well developed in Bruce area. WoS upside potential includes potential future tiebacks to Laggan (e.g. Tornado) and upside associated with WOSPS - see WOSPS slide.
Risks	Early closure of SGP if throughput volumes not maintained. Reliant on future production from Bruce and Norwegian Martin Linge hubs for post 2030 volumes.



2025 Gas production share



Remaining gas reserves



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*Note: WOSPS reserves and production has been split equally between FUKA and SEGAL to reflect future optionality of using EOS or SIRGE for gas export to St Fergus. *Calculated using NSTA reported sales gas volumes which may differ to throughputs reported by National Gas due to measuring and reporting differences.*

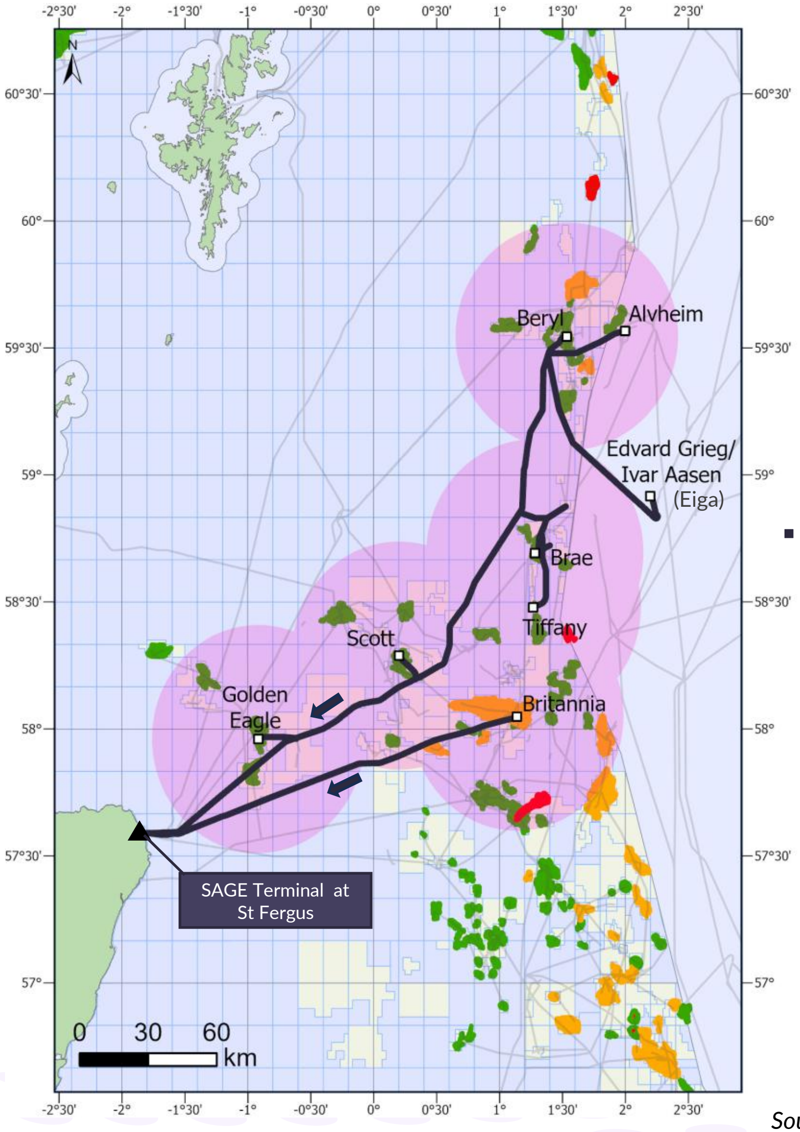
Source: Westwood Energy Atlas
Reserves at 1 January 2026

St Fergus SAGE

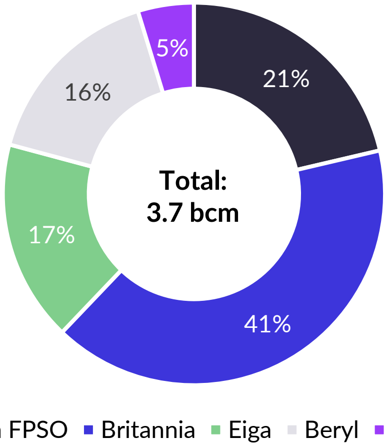
The SAGE system transports gas from the NNS, CNS and Norway through two pipelines and accounted for c. 6% of UK gas throughput in 2025

Operator	Ancala Midstream
Terminal	SAGE Terminal, St Fergus
Overview	Scottish Area Gas Evacuation (SAGE) System comprises the SAGE and Beryl offshore pipelines. A second pipeline delivers gas from the Britannia hub . Extracted liquids from the St Fergus SAGE terminal can be routed to either the Fife NGL plant at Mossmorran (operated by Shell) or the Kinneil plant at Grangemouth (operated by INEOS).

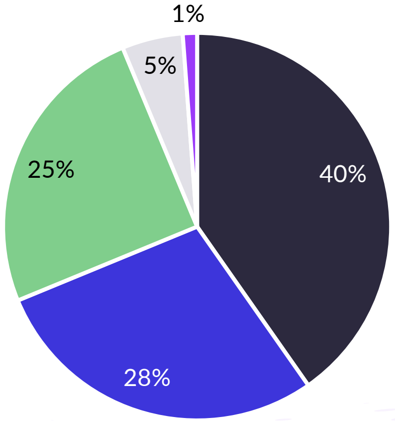
Upside potential summary and risks	
Current outlook	Investment and new developments ongoing at Norwegian hubs and Britannia in UK. Scott infill drilling is limited. Beryl hub production to cease in 2029. Several hubs expected to economically cease production before 2030.
Upside potential	Near term developments at Buchan Horst and Fotla. Multiple commercial discoveries, including Leverett. Untapped gas in Quad 9. Infill drilling opportunities across multiple assets. Upside potential around Norway hubs.
Risks	Reliance on Britannia and Norwegian hubs. Longevity from Norway hubs of Alvheim and Eiga (the new name for the Edvard Greig/Ivar Aasen area), which are expected to produce into 2040s, but have alternate gas export routes nearby. c. 40% of production in 2030 comes from hubs linked to the FPS liquids route.



2025 Gas production share



Remaining gas reserves



Source: Westwood Energy Atlas
Reserves at 1 January 2026

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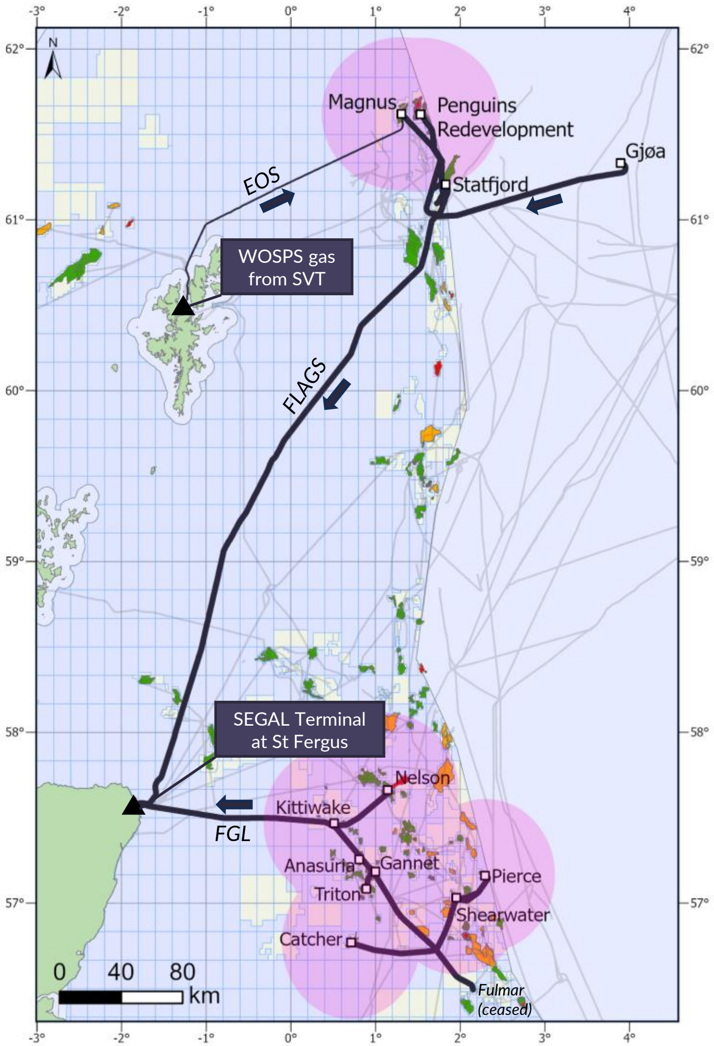
St Fergus SEGAL

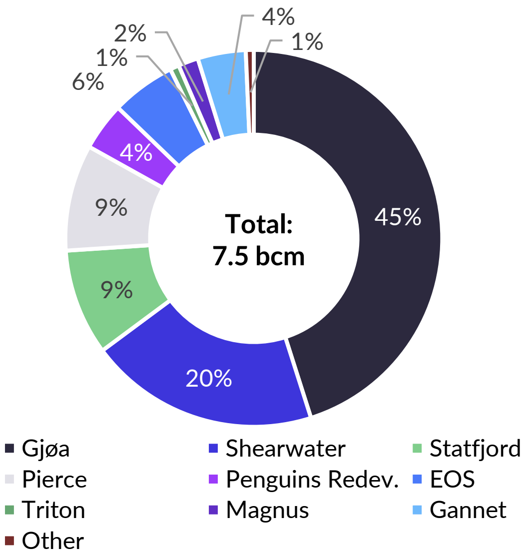
The Shell Esso Gas and Associated Liquids system (SEGAL) at St Fergus processes gas from two lines - the Far North Liquids and Associated Gas System (FLAGS) and the Fulmar Gas Line (FGL)

Operator	Shell
Terminal	SEGAL Terminal, St. Fergus
Overview	FLAGS pipeline transports gas from NNS hubs and FGL transports gas from the hubs in the CNS area. Gas from WOSPS (in West of Shetland) is routed from the Sullom Voe Terminal via the East of Shetland (EOS) pipeline to Magnus and into FLAGS. An alternative route (XOVER) between SVT and SIRGE will be operational from mid-2026, giving the option to route WoS gas to SIRGE and FUKA system. Separated condensate is routed to the Shell Fife NGL terminal at Mossmorran, and the Braefoot Bay tanker loading system.

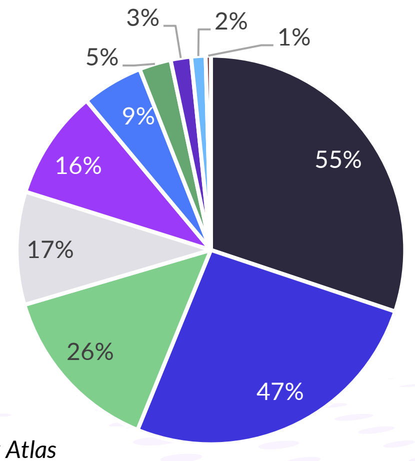
Upside potential summary and risks	
Current outlook	Penguins Redevelopment brought online in Q1 2025. Ongoing investment at Statfjord.
Upside potential	Infill drilling opportunities at Magnus & Penguins. Exploration well near Penguins in 2026. Lack of commercial discoveries and near-term developments in UK NNS. Gjøa production forecast to late 2030s, with number of near field opportunities. Substantial upside in licenced technical discoveries and unlicenced prospectivity on UKCS, but risk of not being progressed.
Risks	Longevity from Statfjord and Gjøa (both Norway) entrants, to late 2030s but alternate export routes could be accessed. Much of upside is unlicenced.



2025 Gas production share



Remaining gas reserves



Note: Split of WOSPS reserves (production routed through EOS into FLAGS) is displayed on page 34

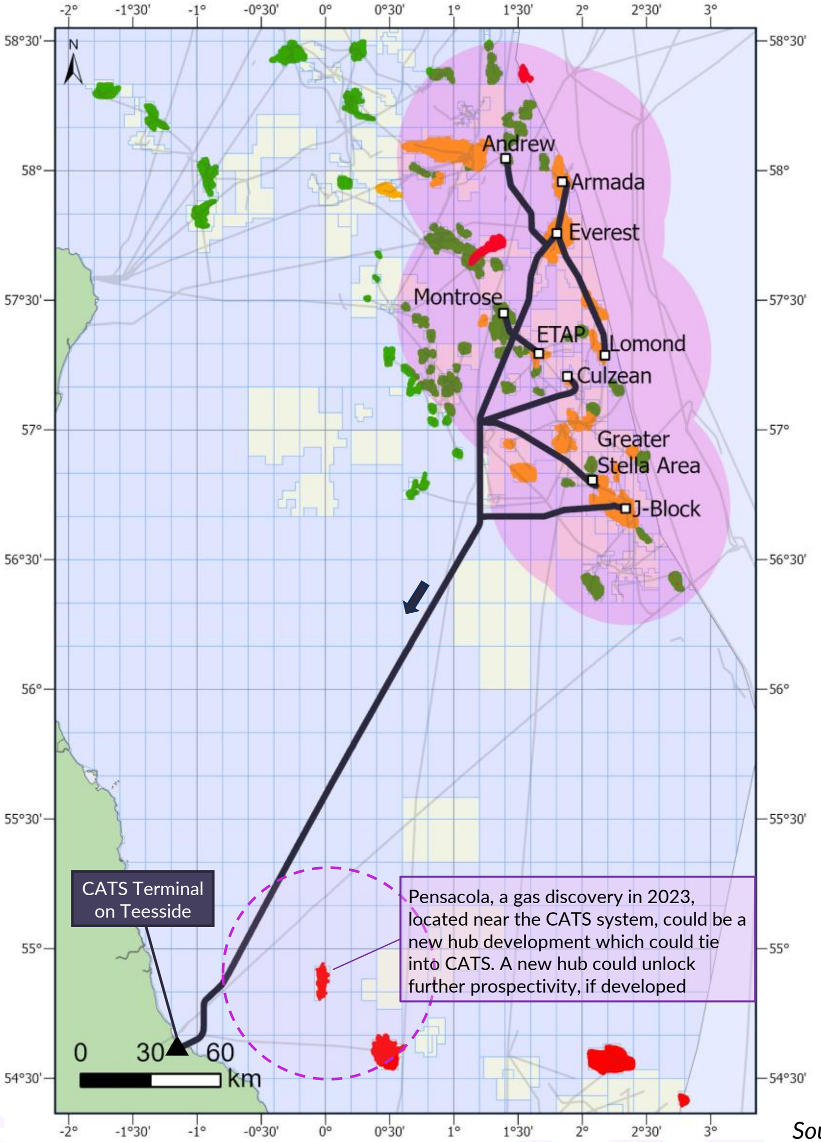
Source: Westwood Energy Atlas
Reserves at 1 January 2026

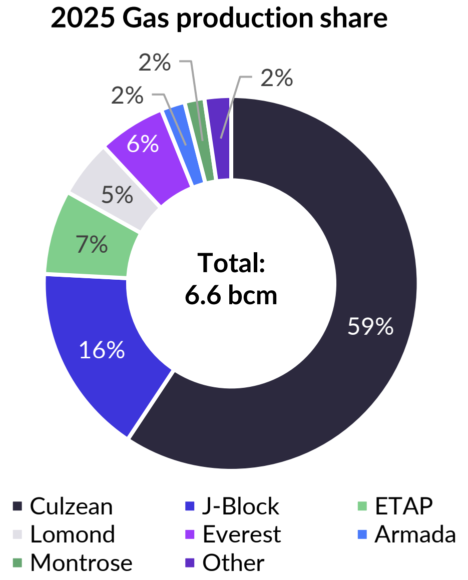
Teesside CATS

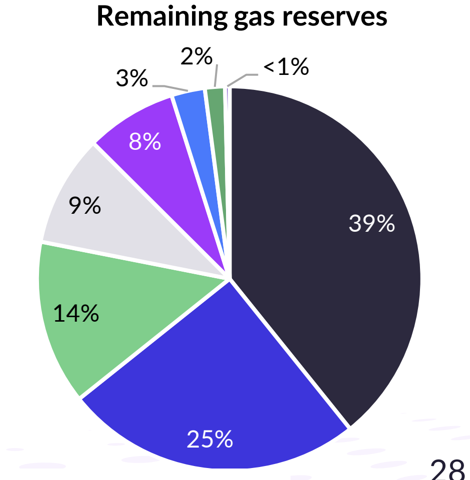
CATS (Central Area Transmission System) is the largest gas transport system in the UK, accounting for c. 25% of gas throughput volumes (30% of UK gas production)

Operator	Kellas Midstream
Terminal	CATS gas processing plant, Teesside
Overview	CATS pipeline transports gas from 41 fields on the UKCS to the CATS terminal at Teesside where contaminants are removed before gas is routed to either the CATS gas processing plant (two processing trains each with 17 mcm/d capacity), or the dedicated processing train at the NSMP Teesside Gas Processing Plant (TGPP). A new gas condensate route was commissioned in 2024 which transports condensate from the CATS terminal to TGPP. In 2025, CATS gas processing plant processed 80% of gas from the CATS system, based on National Gas system entry data. While the specific commercial contracts determine which field entrants utilise CATS over TGPP for processing, it is possible to deduce that Culzean utilises the CATS plant. Westwood has apportioned 80% of CATS field entrants' reserves to CATS gas processing plant, however, future throughput may vary depending on commercial arrangements. Due to the optionality for field operators, Westwood has apportioned 50% of resource upside to CATS processing plant and 50% to TGPP.

Upside potential summary and risks	
Current outlook	Throughput rates are currently high as Culzean is still producing at plateau rate. Development well brought onstream late 2025, uplifting production. Murlach (tie-back to ETAP) started production in October 2025. There is ongoing drilling at ETAP and J-Block.
Upside potential	Exploration well planned in Culzean area (existing licence), and tieback opportunities exist at several hubs. Other drill ready exploration prospects within hub catchments. Significant upside potential was licenced in the 33rd Licensing Round (2023 - 2024). Additional upside exists along the pipeline route, including at Pensacola, a recent gas discovery. Crosgan appraisal drilling was successful in 2025, possible tieback to Pensacola.
Risks	75% of current throughput is from 2 hubs. Risk of closure in mid 2030s, which would impact UKCS.







Note: Production and reserves from the CATS system are pro-rated between the CATS processing plant and TGPP based on 2025 throughput share

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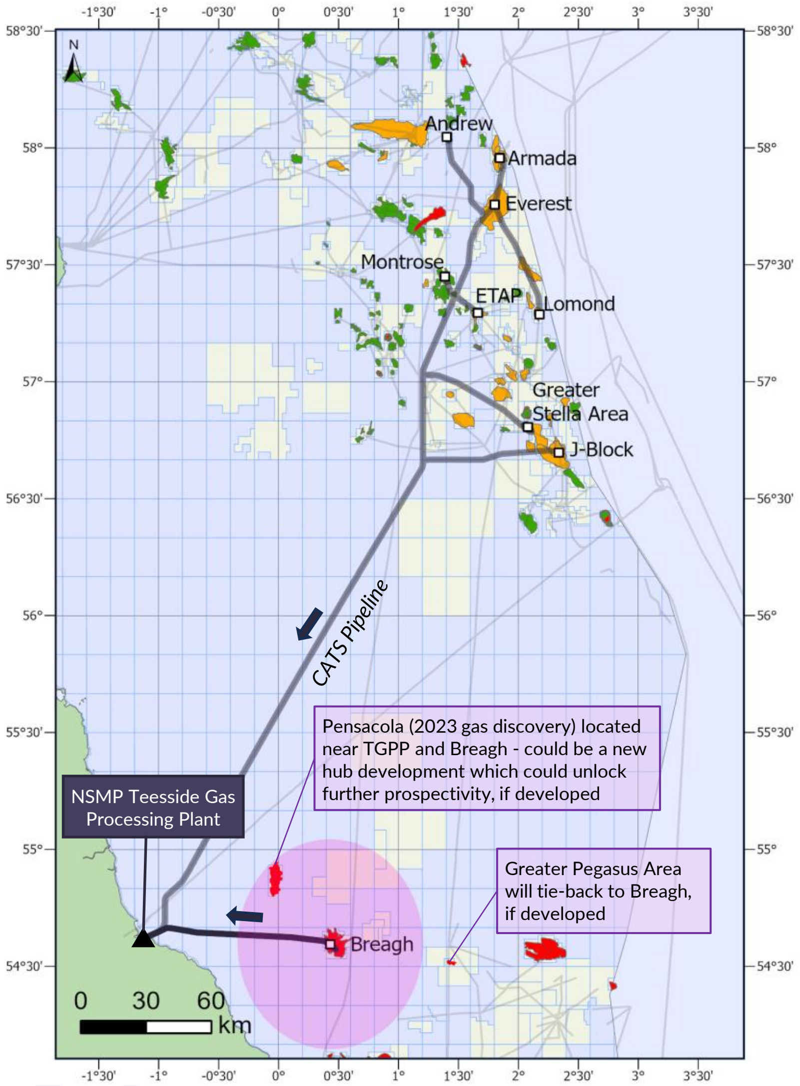
Source: Westwood Energy Atlas
Reserves at 1 January 2026

Teesside TGPP

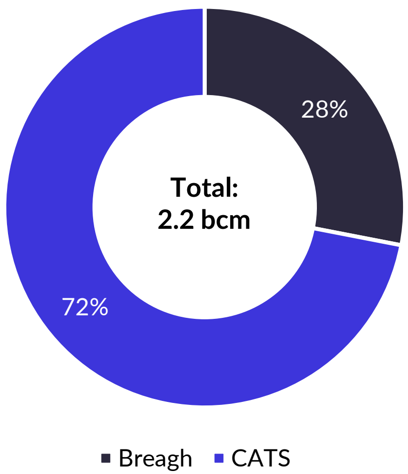
The NSMP Teesside Gas Processing Plant (TGPP) processes gas from the Breagh hub in the SNS as well as the CATS pipeline system

Operator	NSMP
Terminal	Teesside Gas Processing Plant (TGPP)
Overview	TGPP has two processing trains, one processes gas from the Breagh field. In 2024, an onshore compressor commenced operation to support Breagh production. A second processing train takes gas from the CATS pipeline system. In 2025 TGPP processed 20% of gas from the CATS system, based on National Gas system entry data. While the specific commercial contracts determine which field entrants utilise TGPP over CATS for processing, it is possible to deduce that Culzean utilises the CATS plant. In 2025, TGPP processed 20% of the total CATS pipeline throughput. Westwood has apportioned 20% of CATS field entrants' reserves to TGPP, however, future throughput may vary depending on commercial arrangements. Due to the optionality for field operators, Westwood has apportioned 50% of resource upside to TGPP and 50% to CATS processing plant.

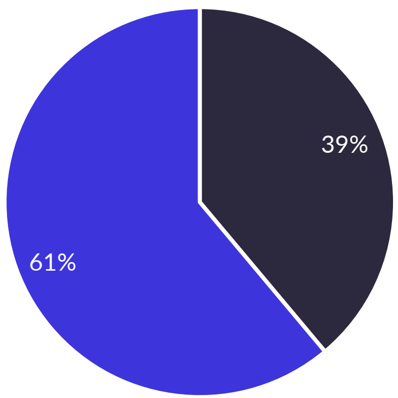
Upside potential summary and risks	
Current outlook	Strong production response in 2025 at Breagh from the onshore compression project. Due to partial onshore electrification at TGPP, Breagh has the lowest emissions intensity of any UK hub.
Upside potential	Possibility for Pensacola to utilise TGPP or CATS. INEOS is evaluating plans to develop Pegasus West to the Breagh A platform. This is beyond 50 km from Breagh but has been included in the resource upside for TGPP and offers a total of c. 6.1 bcm upside from five discoveries. There is a commitment well for the Pegasus licence. Crosgan appraisal drilling was successful in 2025, possible tieback to Breagh or Pensacola. The northern part of the SNS is largely considered to be under-explored – roughly half of upside potential is found in unlicenced prospectivity and thus is stranded. TGPP can compete for future CATS pipeline system production with the CATS processing plant.
Risks	Currently, the SNS infrastructure is reliant on production from a single field (albeit with an attractive production outlook) and CATS pipeline throughput volumes. Pensacola presents upside but gas properties are a development risk.



2025 Gas production share



Remaining gas reserves



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* Includes Greater Pegasus Area discoveries, despite being greater than 50 km away, due to INEOS stated preferred export route via Breagh, should Pegasus reach production

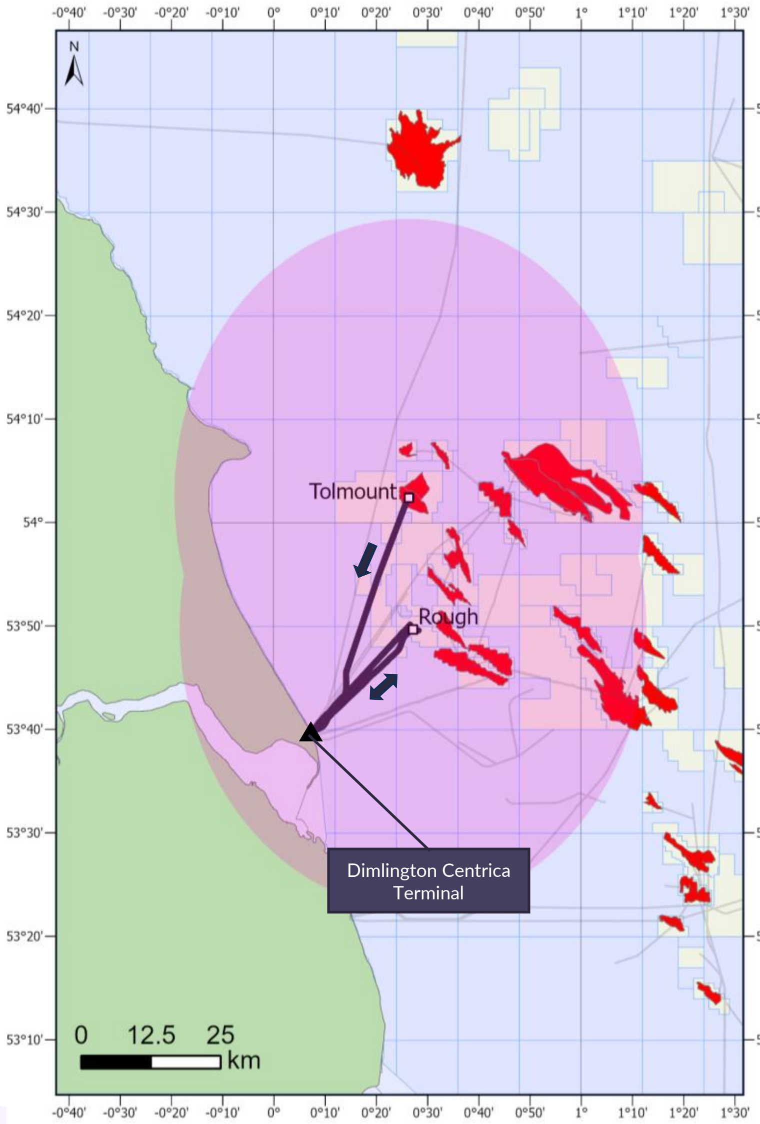
Source: Westwood Energy Atlas
Reserves at 1 January 2026

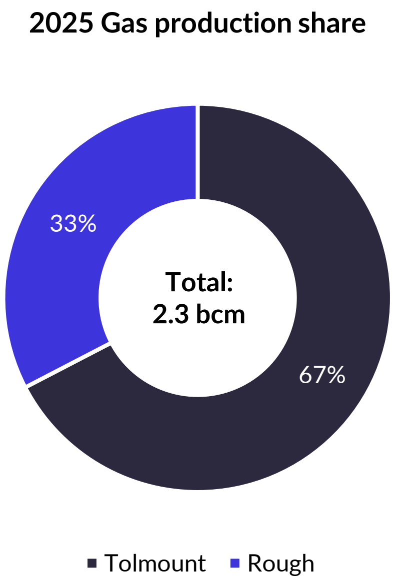
Dimlington Centrica

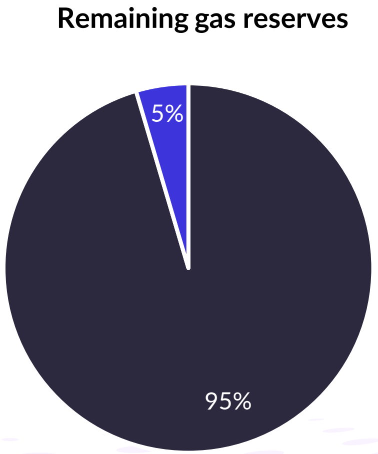
Dimlington Centrica is an onshore terminal which gathers and processes gas from the Tolmount field and the Rough gas storage facility

Operator	Centrica
Terminal	Dimlington/Easington Gas Terminal (Centrica)
Overview	There are two gas pipelines that transport gas to Centrica's Dimlington gas terminal. The 47 km long, 20" diameter, pipeline transporting produced gas from the Tolmount hub, which commenced production in 2022, and the 30 km, 36" pipeline connected to the Rough gas storage facility, which restarted operations in 2022.

Upside potential summary and risks	
Current outlook	Tolmount hub production is entering decline but has a reasonable remaining field life expected. Uncertainty over the future of Rough – reliant on government.
Upside potential	Material upside is contained in commercial discoveries within 50 km of the Tolmount hub. Petrogas appraised the Abbey discovery and discovered Baker in 2024/25. One development concept being considered is a tie-back to Tolmount.
Risks	Reliant on a two-field hub (Tolmount) and the future of gas storage operations at Rough.







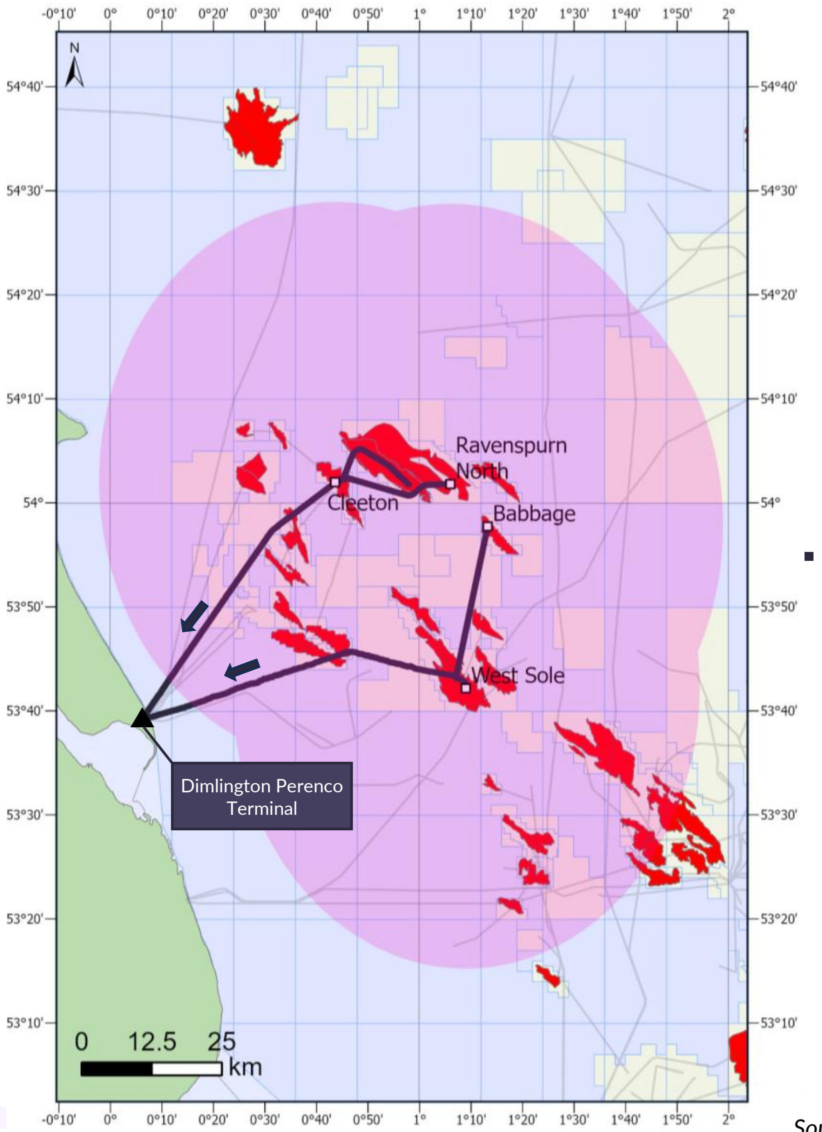
Source: Westwood Energy Atlas
Reserves at 1 January 2026

Dimlington Perenco

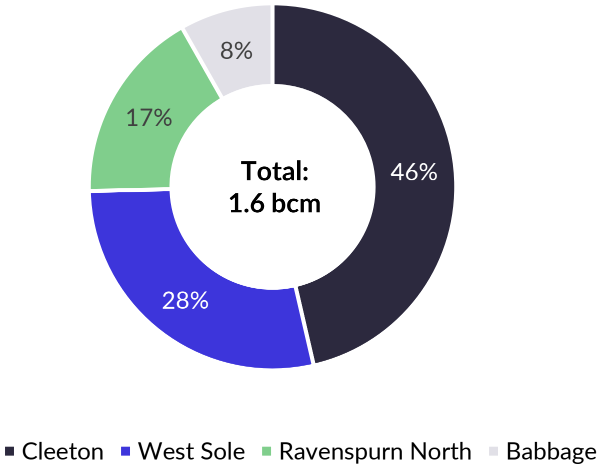
Dimlington Perenco is an onshore terminal which gathers and processes gas from four SNS hubs and includes the West Sole pipeline and the Easington Catchment Area (ECA) pipeline

Operator	Perenco
Terminal	Dimlington Perenco
Overview	Dimlington Perenco processes gas from four SNS hubs from two pipeline systems. The Ravenspurn North hub exports gas via a 26 km long, 24” pipeline to the Cleeton hub where it is commingled with gas from the Cleeton hub and exported to shore through the 36”, 58 km Easington Catchment Area (ECA) pipeline. The Babbage hub exports gas via a 12”, 28 km pipeline to the West Sole hub where the gas is commingled with fluids from two fields in the West Sole hub before export to Dimlington via a 24”, 68 km pipeline. An additional 16”, 72 km pipeline also transports gas from the West Sole hub.

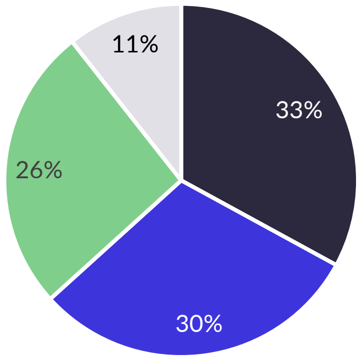
Upside potential summary and risks	
Current outlook	Perenco intends to repurpose the West Sole field as part of the Orion CCS project with first injection by 2031. Well interventions ongoing across various fields, but no significant investment expected before 2030.
Upside potential	A high number of infill opportunities on the existing fields have been evaluated and could progress if fiscal terms improve. This builds on the success of the infill well drilled on Ravenspurn South in 2024 which gave a 50% increase in production. Up to 28.3 bcm of gas resources could be recovered in Dimlington and Bacton areas to arrest rate of production decline.
Risks	Production decline rates are expected to increase post 2026 due low level of planned investment.



2025 Gas production share



Remaining gas reserves



Source: Westwood Energy Atlas
Reserves at 1 January 2026

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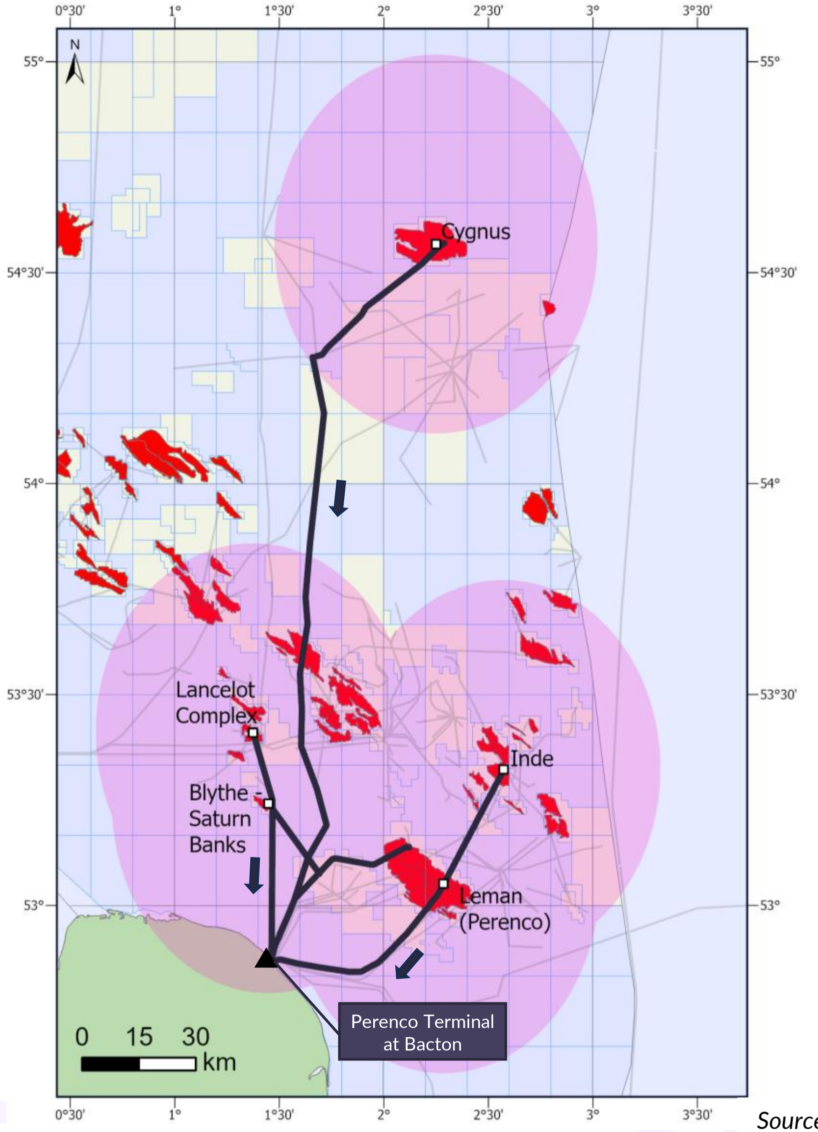
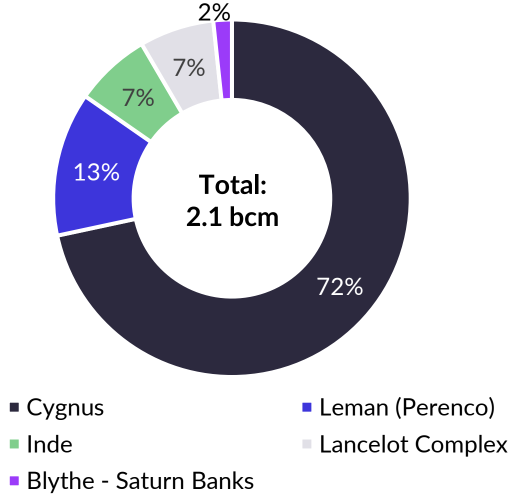
Bacton Perenco

The Bacton Perenco onshore terminal gathers and processes gas from several pipelines including East Anglia Gas and Liquids Evacuation System (EAGLES), Thames, Inde, Leman (Perenco) and Lancelot Area Pipeline System (LAPS)

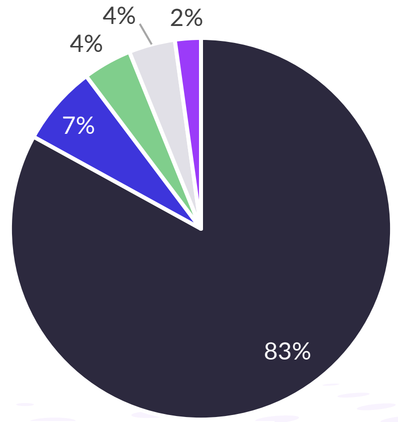
Operator	Perenco
Terminal	Perenco Terminal, Bacton
Overview	Bacton Perenco receives gas from several SNS pipelines. Gas from the Blythe-Saturn Banks hub is transported to Bacton via the recommissioned Thames pipeline. The new-build 24 km, 12” pipeline tees into the recommissioned 24” Thames pipeline for export 29 km to Bacton. EAGLES, formerly known as Esmond Transmission System (ETS), transports gas c. 215 km from the Cygnus field along a 24” diameter pipeline. The Lancelot Area Pipeline System (LAPS) is a 20” diameter, 62 km pipeline transporting gas from the Lancelot hub. Following the Southern Hub Asset Rationalisation Project (SHARP), the Inde hub now exports gas via a 36 km, 30” pipeline to the Leman 49/27BC platform. Gas from the Inde and Leman (Perenco) hubs are then transported 65 km via a 30” pipeline to Bacton.
Upside potential summary and risks	
Current outlook	Investment ongoing at the Cygnus field including infill drilling. In 2023, Cygnus production has benefited from a minor change to the lower end of the Wobbe Index. Cygnus production had been reliant on blending with other gas processed at the Perenco Bacton Terminal to meet the National Grid entry specification. The need for sufficient volumes of blend gas has impacted Cygnus production until the specification change.
Upside potential	Infield upside opportunities exist at the Bacton Perenco entrants. A four-well infill drilling campaign is ongoing at Cygnus. Perenco intends to connect the Blythe-Saturn Banks hub to its LAPS compressor at Bacton in 2026 which should maintain production and enable resumption of production from shut-in wells. Recent well interventions have taken place at Leman, arresting production decline. During the 33rd Licensing Round the NSTA promoted the Greater Cygnus Area Cluster containing the Kepler, Copernicus and Winchelsea discoveries (totalling c. 7.2 bcm). 37% of the potential upside surrounding the Bacton Perenco entrants is unlicenced prospectivity and therefore is stranded.
Risks	Heavily reliant on Cygnus for production volumes.



2025 Gas production share



Remaining gas reserves



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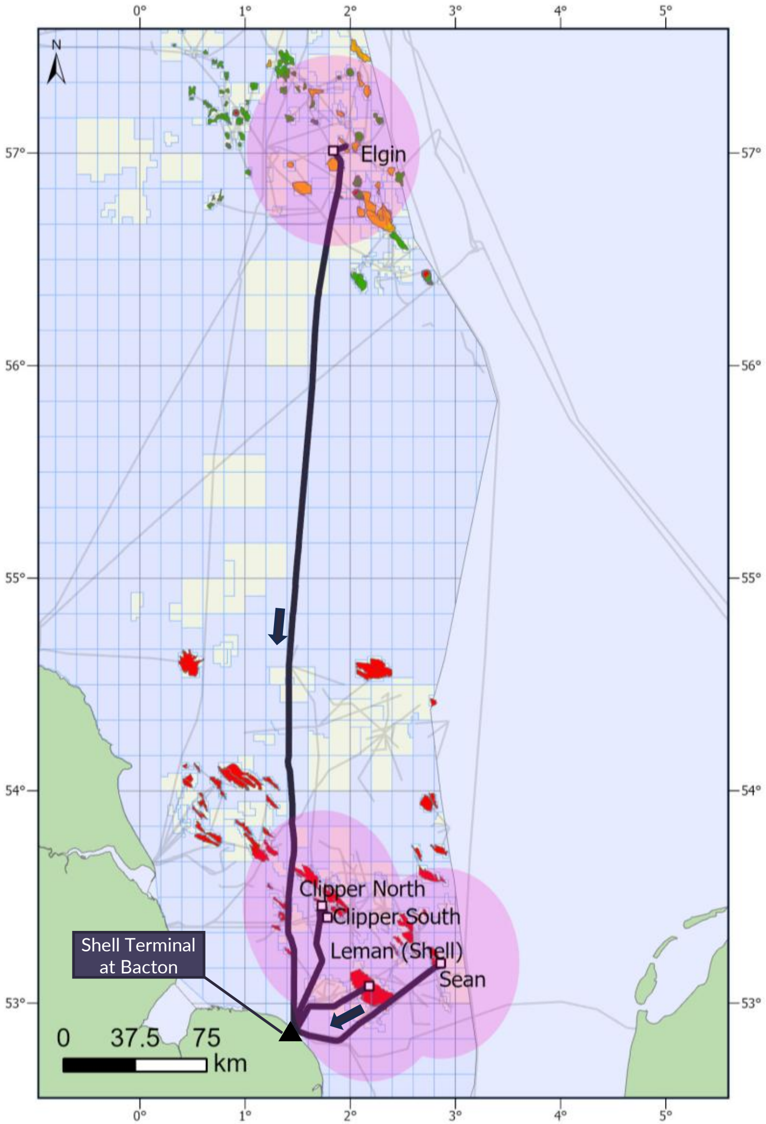
Source: Westwood Energy Atlas
Reserves at 1 January 2026

Bacton Shell

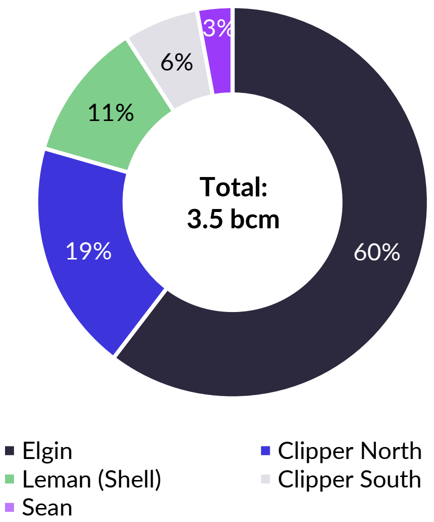
The Bacton Shell onshore terminal gathers and processes gas for the Clipper pipeline and Leman (Shell) pipeline in the SNS. It also processes gas from the Shearwater and Elgin Area Line (SEAL) in the CNS

Operator	Shell
Terminal	Shell Terminal, Bacton
Overview	The Shell Bacton Terminal processes gas from four SNS hubs through three separate pipelines, and from one CNS hub via the SEAL pipeline. The Shearwater hub previously utilised the SEAL pipeline, but production was rerouted to the SEGAL Fulmar Gas Line (FGL) in 2021.

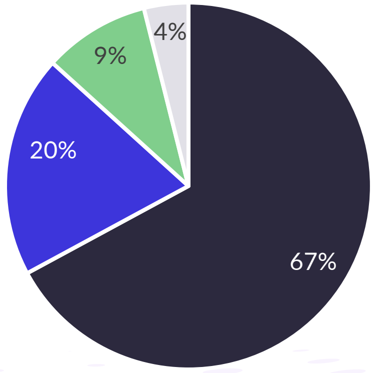
Upside potential summary and risks	
Current outlook	At Elgin, EIH HPHT infill well planned to be drilled in 2026. Valaris Stavanger rig onsite completing various well intervention and P&A activities, remaining on contract until April 2027. Ongoing well intervention work and potential for infill drilling in near-term. TotalEnergies UK is planned to merge with NEO NEXT in 2026 to form NEO NEXT+. The UK focused player expected to have improved UK investment appetite than TotalEnergies. Planned acquisition of Shell operated SNS assets (in deals with both Shell and ExxonMobil owners) by Viaro cancelled in January 2026 and Shell will retain operatorship of assets and infrastructure.
Upside potential	Infill drilling opportunities at Elgin. LPP compression and flare gas recovery projects proposed. Potential for Anning-Sommerville near-term development is via the Leman (Shell) infrastructure. The preferred development concept for the 2024 Selene discovery is via the Clipper infrastructure.
Risks	Production throughput is heavily reliant on Elgin hub production performance. Ownership uncertainty over the last 18 months has likely delayed strategic planning related to the SNS assets included in the Viaro deal, and therefore potential investment plans.



2025 Gas production share



Remaining gas reserves



Source: Westwood Energy Atlas
Reserves at 1 January 2026

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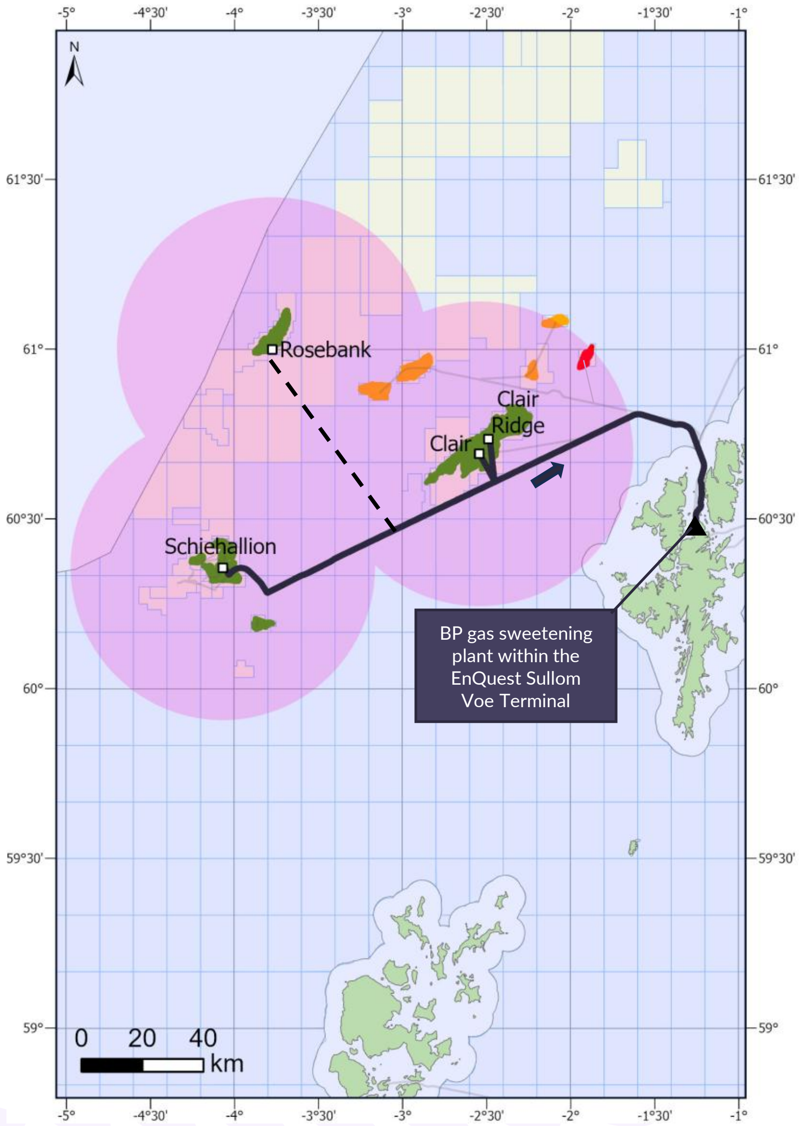
WoS Gas Pipeline System (WOSPS)

WOSPS transports the associated gas from production at Schiehallion, Clair and Clair Ridge to the Sullom Voe Terminal, then via the East of Shetland pipeline to Magnus and then SEGAL FLAGS

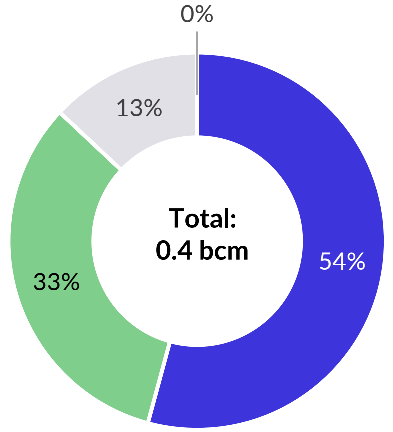
Operator	BP
Terminal	Sullom Voe Terminal (SVT), operated by EnQuest, then routed to Shell SEGAL Terminal at St Fergus via EOS and FLAGS
Overview	There are two main gas pipeline systems in the West of Shetland region. The 20" diameter, 188 km WOSPS pipeline transports export gas from the BP operated Clair, Clair Ridge and Schiehallion, Loyal and Alligin fields to the EnQuest operated SVT. From SVT some gas is routed through the East of Shetlands Pipeline System (EOS) to the Magnus platform. From here gas is routed through the SEGAL FLAGS pipeline to the Shell SEGAL Terminal at St Fergus. There is also a tie-in point for gas to feasibly route into SIRGE and the FUKA system, which could be used in the future for WOSPS gas, this is expected to be operational in 2026.

Upside potential summary and risks	
Current outlook	Infill drilling ongoing at Clair Ridge. Rosebank development expected online in 2027.
Upside potential	Plans to resume infill drilling programmes at Clair and Schiehallion. Clair Ridge has a multi-year drilling programme ongoing. Development of the Cambo discovery. Clair South and Rosebank Phase 2 commercial discoveries. Significant unlicenced volumes in technical discoveries and prospectivity.
Risks	Rosebank production performance. Reduced infill drilling programmes in the future. Much of upside is unlicenced.

Oil and liquids production exported via tanker (Schiehallion) or via Clair oil pipeline to Sullom Voe Terminal

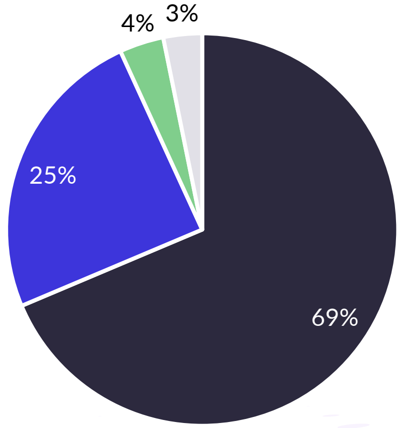


2025 Gas production share



■ Rosebank ■ Clair Ridge ■ Schiehallion ■ Clair

Remaining gas reserves



Source: Westwood Energy Atlas
Reserves at 1 January 2026

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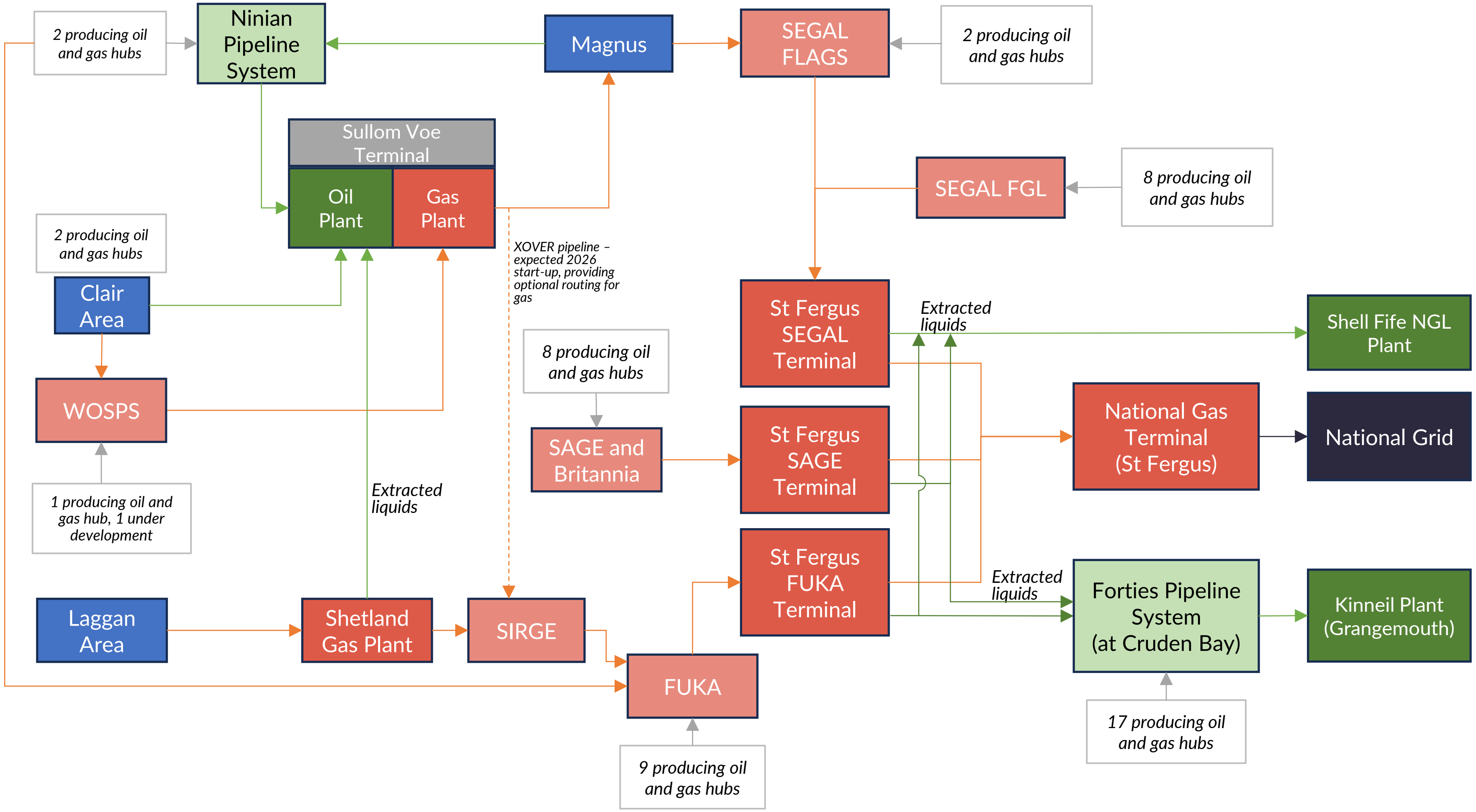
National Gas Terminal at St Fergus

The northern transport system shown here for gas and oil delivered 45% of UK produced oil and 32% UK produced gas in 2025



The Shell Fife Natural Gas Liquids plant (FNGL) receives NGL from the St Fergus gas terminals. The incoming natural gas liquid is separated at FNGL into propane, ethane, butane and natural gasoline.

The FNGL plant is adjacent to the ExxonMobil operated Fife Ethylene Plant (FEP) which shut down operations on 2 February 2026, impacting 400 jobs (according to Unite).

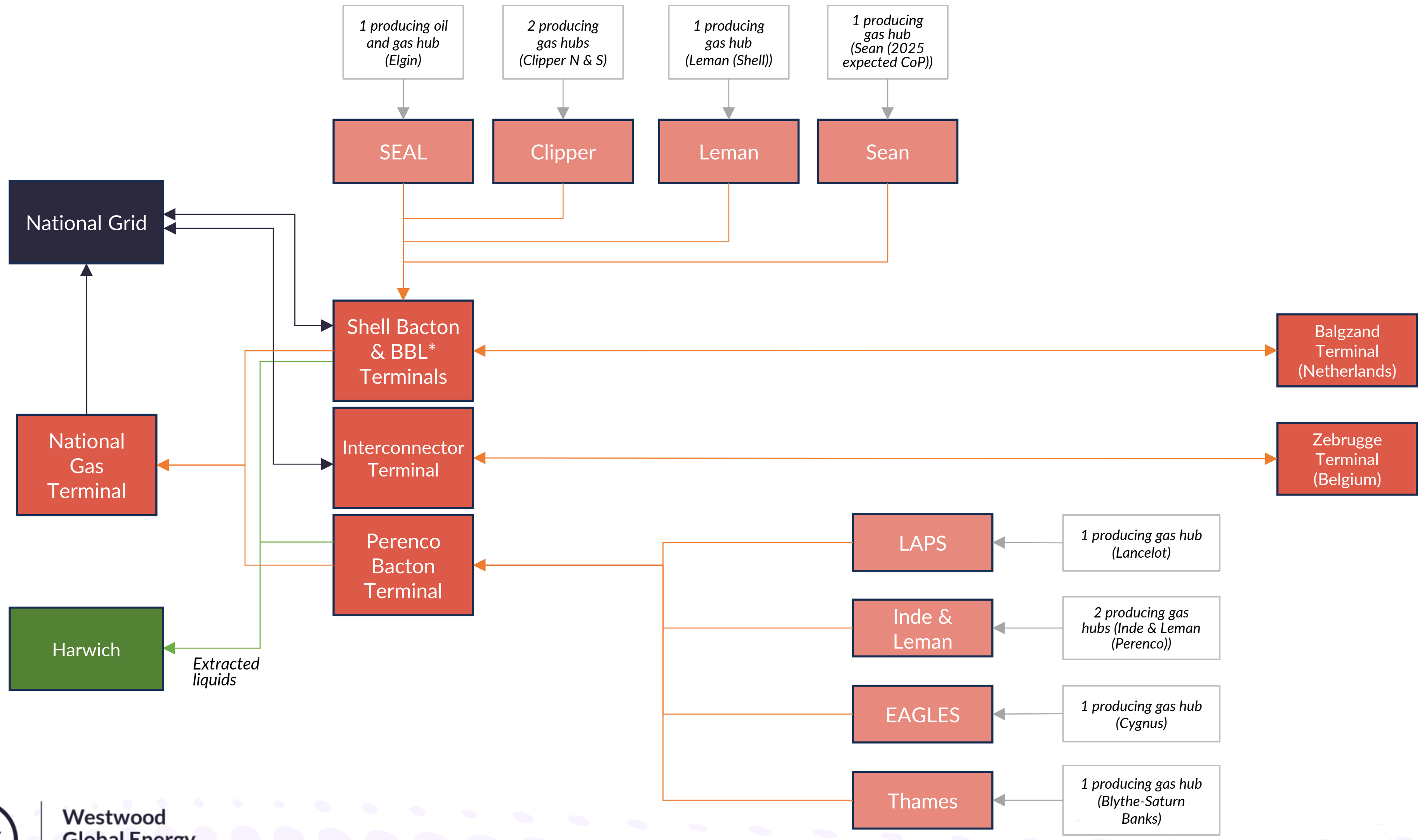
Definitions:

Hub - Manned processing centre for field(s), may be fixed platform(s) or floating facility. These installations support drilling, production, processing and export of the oil and gas and are 'self sufficient' with the accommodation and catering crews to support staff while offshore.

Terminal/Plant - Onshore facility for final processing of oil, gas or gas/liquids ahead of sale and export to refineries or National Grid.

National Gas Terminal at Bacton

National Gas owns and operates two major gas terminals in the UK, at St Fergus and Bacton. The Bacton site sources gas from three main pipeline systems and nine hubs and accounts for c. 21% of UK produced gas in 2025



Liquids extracted from the Bacton terminals has historically been piped to North Walsham before being transported by a tanker train to Harwich for further processing.

On 4 August 2025, Haltermann Carless announced plans to exit from its low-margin commodity businesses, including the gas condensate business with the closure of a production unit in Harwich. The most likely alternative route for extracted liquids is either Teesside or Rotterdam.

Definitions:

Hub - Manned processing centre for field(s), may be fixed platform(s) or floating facility. These installations support drilling, production, processing and export of the oil and gas and are 'self sufficient' with the accommodation and catering crews to support staff while offshore.

Terminal/Plant - Onshore facility for final processing of oil, gas or gas/liquids ahead of sale and export to refineries or National Grid.

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*BBL – Bacton-Balgzand Line

Source: Westwood Energy Atlas

Appendix

Selected pages from the Westwood Summary Report for OEUK, published in June 2025 “Potential of the UKCS under different scenarios”

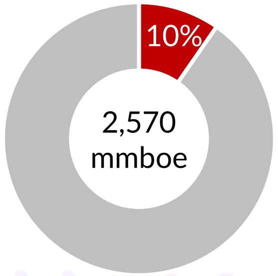
Full report is available here:
https://oeuk.org.uk/product/ukcs-outlook-scenarios-consultation-report/

UKCS Outlook: Key Messages

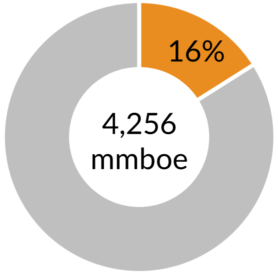
Significant resource potential remains in the UKCS, however, a shift in external conditions and investor sentiment is required for it to be tapped

- Three key consultations in 2025 could shape the future of the industry.
- Based on current investment plans, Westwood estimates that there are c. 3.1 billion boe (bnboe) in remaining reserves in fields that are currently producing, under development or classed as near-term developments (plans progressed but not yet sanctioned). However, significant resource potential remains in undeveloped discoveries and prospects.
- Westwood estimates a total of c. 26.5 bnboe of potential reserves and resources in the UKCS. Of this, c. 13 bnboe is within 25 km of an existing production hub catchment area, and c. 19 bnboe within 50 km of a hub. However, much of this lies on unlicensed acreage and only a small proportion of this will be developed under current conditions.
- Westwood modelled 3 development/investment scenarios. Of the 26.5 bnboe of total potential reserves and resources in the UKCS, c. 10% could be recovered under the Low Case, 16% under the High Case and up to 28% under the 'No Constraints' Case. However, the latter would require a major shift in external conditions and investor sentiment.
- Different scenarios are reflective of the investment environment, not the subsurface opportunities. This influences production outlooks and recoverable reserves estimates, which have been revised downward in recent years, due to changes in sentiment. In 2019, the NSTA projected that 6.5 bnboe could be recovered from the UK North Sea between 2025 and 2050 but in 2024 this figure was reduced to 3.8 bnboe.

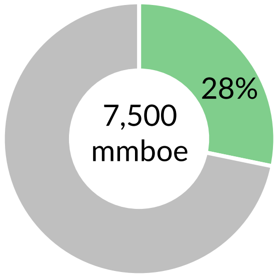
Low Case: assumes no future sanctions or E&A drilling, with near term developments left untapped and lower production performance in assets under development



High Case: accelerated but achievable developments from increased infield recovery, near term developments, commercial discoveries and some exploration success



No Constraints Case: assumes a major shift in external factors and investor sentiment to recover more from existing fields and untap more of the technical discoveries and prospectivity



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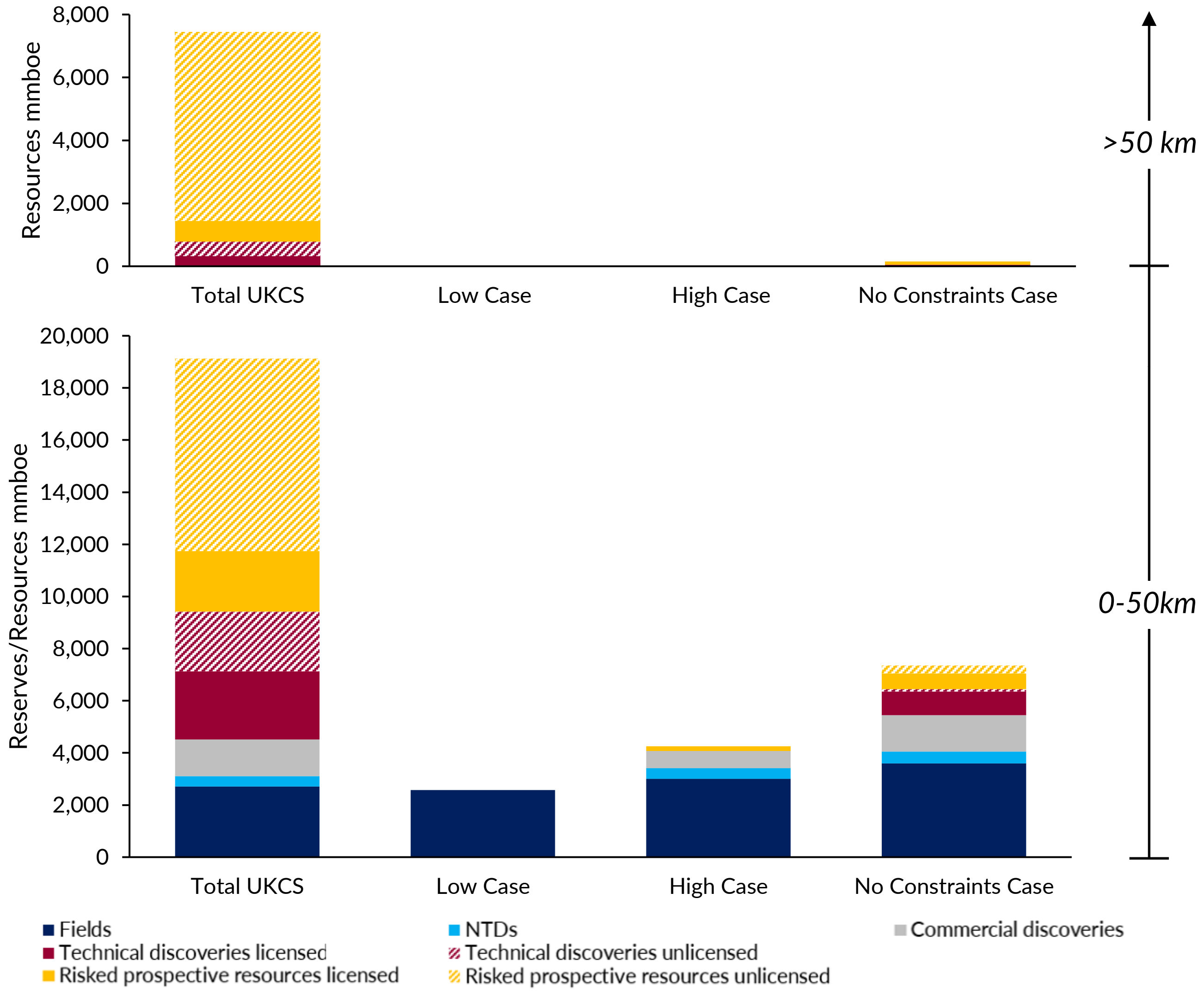
Note: Remaining reserves effective at 1 January 2025

Source: Westwood Atlas

UKCS resource potential

Of the total UKCS potential reserves and resources, c. 10% could be recovered in the Low Case, 16% in the High Case and up to 28% in the 'No Constraints' Case. However, the latter would require a radical shift in external conditions and investor sentiment

Westwood's reserves and resources category	Total UKCS reserves/ resources	Low Case: Reserves/ resources potential	Low Case: % Recovered	High Case: Reserves/ resources potential	High Case: % Recovered	No Constraints Case: Reserves/ resources potential	No Constraints Case: % Recovered
Fields (producing and under development)	2,710*	2,570	95%	3,008	111%	3,600	133%
NTDs	402	0	0%	402	100%	445	111%
Commercial discoveries	1,405	0	0%	658	47%	1,405	100%
Technical discoveries licensed (within 50km)	2,608	0	0%	0	0%	900	35%
Technical discoveries unlicensed (within 50km)	2,293	0	0%	0	0%	100	4%
Risked prospective resources licensed (within 50km)	2,317	0	0%	188	8%	600	26%
Risked prospective resources unlicensed (within 50km)	7,388	0	0%	0	0%	300	4%
Technical discoveries licensed (beyond 50km)	330	0	0%	0	0%	50	15%
Technical discoveries unlicensed (beyond 50km)	452	0	0%	0	0%	0	0%
Risked prospective resources licensed (beyond 50km)	667	0	0%	0	0%	100	15%
Risked prospective resources unlicensed (beyond 50km)	5,993	0	0%	0	0%	0	0%
Total	26,565	2,570	10%	4,256	16%	7,500	28%



Assumptions and Methodology can be found in original report. Available here:
https://oeuk.org.uk/product/ukcs-outlook-scenarios-consultation-report/

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**Total UKCS reserves in producing and under development fields is compared to Westwood's base case forecast, which only models firm infield development plans e.g. infill wells with a drilling application approved or workovers with a rig contract in place etc.*

Source: Westwood analysis for OEUK 2025

Glossary of terms

Glossary of terms

Term	Meaning
Abandon or decommission	To safely retire an oil or gas installation once it has reached the end of its production life. This includes a series of technical, environmental, and regulatory steps to ensure that the site is left in a safe and clean condition
AR7	Allocation Round 7 of the UK Contract-for-Difference scheme for low-carbon electricity (including offshore wind)
Associated gas	Many reservoirs have a mix of hydrocarbon type. Oil reservoirs will have an associated gas content, which can be processed at the hub and exported. The gas may be contained in the reservoir as free gas, as a gas cap over the oil-bearing interval and/or be dissolved in the liquids and be produced as the reservoir pressure drops and the gas comes out of solution
BBL	Bacton–Balgzand Line - interconnector pipeline transporting gas between the UK and the Netherlands
bcm	Billion cubic metres
100 bcm	= 1,100 TWh (Terra Watt hours) – sourced from DESNZ Gas Security Consultation document
1 bcm	= 11,000 GWh (Giga Watt hours) – sourced from DESNZ Gas Security Consultation document
boe	Barrel of oil equivalent (c. 159 litres per barrel)
Brent spot price	The benchmark global crude oil price based on Brent blend
CATS	Central Area Transmission System - the UK's largest gas pipeline system, takes gas from the CNS to Teesside where it can be processed at either the CATS gas processing plant or TGPP
CCS	Carbon Capture and Storage - capturing CO_2 and storing it underground
Cessation of Production (CoP)	To cease producing oil and gas from a well, field or hub when it becomes unprofitable
CfD	Contract for Difference - UK government mechanism guaranteeing power price stability for low-carbon projects (e.g. offshore wind)
CNS	Central North Sea
Commercial discovery	A well drilled into a reservoir that is deemed to have encountered adequate quantities of oil/gas to support production.
Condensate	Condensate is a light hydrocarbon liquid that is typically produced along with natural gas from gas-condensate reservoirs. It forms when the pressure and temperature of the gas drop during production, causing heavier hydrocarbons to condense out of the gas phase
DESNZ	Department for Energy Security and Net Zero
Dry gas	Natural gas with little or no condensate or NGL content, typically found in the SNS and require only a gas export route.
E&A	Exploration and appraisal. Exploration wells target 'new' prospects and appraisal wells are follow-on wells drilled to further evaluate the geology of a discovery, help quantification of volumes, measure reservoir conditions and/or take hydrocarbon samples

Source: Westwood Energy Atlas

Glossary of terms

Term	Meaning
EOS	East of Shetland pipeline transporting WoS gas to Magnus and into FLAGS
EPC	Engineering, Procurement and Construction - contracting model for project delivery
EPL	Energy Profits Levy - UK windfall tax on oil and gas profits introduced in 2022, currently set at 38%, taking the total headline tax rate to 78%
ESIM	Energy Security Investment Mechanism - mechanism intended to 'switch off' the EPL when prices drop below threshold levels
FEED	Front-End Engineering and Design phase preceding a final investment decision
FID	Final Investment Decision - commitment to proceed with project development
Field	An accumulation of hydrocarbons that has been sanctioned for development
FPS	Forties Pipeline System - primary liquids export system for many CNS/NNS hubs
FPSO	Floating Production, Storage and Offloading vessel
FSRU	Floating Storage and Regasification Unit - ship-based LNG import and regasification facility
FUKA	Frigg UK Association gas pipeline system - gas transportation and processing system at St Fergus
Hub	The centralised processing facility, complex or gathering station where hydrocarbons are received from one or more fields. Oil, gas, water and/or solids are then separated, treated and processed before being transported to export terminals, refineries or other end users
Infill drilling	Drilling wells between known producing wells to exploit the resources of a field to best advantage
Infrastructure	Pipeline systems and subsea equipment needed to transport hydrocarbons
Licenced	The defined area that is leased to an oil & gas company by a government entity on which they can explore for and develop oil and gas resources. Can also be referred to as licenced blocks or permit area. Nomenclature for this term changes from country to country.
LNG	Liquified Natural Gas is natural gas that has been cooled to a liquid state at approximately -162°C (-260°F) for ease of storage and transportation. In the UK, LNG is imported from overseas gas producers, such as the USA and Qatar. The produced gas is processed and converted to LNG, shipped from the LNG terminal to a UK landing facility and 're-gassed' to enable the gas to be distributed
mcm	Million cubic metres
mcm/d	Million cubic metres per day
NBP gas price	The UK's benchmark wholesale gas price at the National Balancing Point

Source: Westwood Energy Atlas

Glossary of terms

Term	Meaning
Near term development	A commercial discovery which is planned for development with an associated timeframe and firm development concept
NESO	National energy System Operator (government-owned energy system operator)
NESO 10YF	NESO ten-year forecast, is its base case outlook reflecting its latest best view of future demand for gas and power over the next ten years. It considers existing project development and policy action
NGL	Natural Gas Liquids are a group of hydrocarbon liquids that are separated from natural gas during processing. They are found in raw natural gas and are extracted at gas processing plants or refineries
NNS	Northern North Sea
NUI	Normally Unattended Installation - offshore platform that does not require to be permanently manned
OGPM	Oil and Gas Price Mechanism - proposed replacement for the EPL, applying a permanent tax uplift when prices exceed set thresholds
Production modelling	Production modelling is used to forecast future production • Westwood uses a 'bottom-up' approach to modelling, projecting future production at an individual field and hub level based on historic trends and information such as drilling plans or well workovers that would impact on production rates. When combined, these forecasts give a view on future UKCS production. Cessation of production is based on the point the pre-tax operating cashflow of the field and/or hub becomes uneconomic • In contrast, the NSTA implements a 'top-down' approach whereby future production is forecast based on basin-level decline assumptions, by applying a 'stylised compound' decline rate to production on the UKCS scale. The NSTA currently projects a 12% annual decline in gas production volumes. The NSTA's projection of future gas decline rate was revised in 2025, having previously used a 11% decline rate, which itself is a revision from the 5% used in 2016 The NSTA states that "The projected production profiles are deliberately stylised to avoid the impression of spurious accuracy"
Reserves	The term used to describe the volume of hydrocarbons that are considered economically feasible to recover and have been sanctioned for development. Recoverable reserves can also be categorised as proved reserves, probable reserves or possible reserves
Resources	There are two types of resources - contingent (or discovered) and prospective. Contingent resources include oil, liquids and gas volumes that have been discovered through the drilling of an exploration well, but they have not yet been sanctioned for development. Prospective or pre-drill resources are volumes of hydrocarbons that are estimated to exist in undiscovered accumulations. They are yet to be found, but estimated volumes are believed to be present based on geological and geophysical data and analysis
Risked prospective resource	An estimate of the hydrocarbons not yet discovered but believed to exist based on geological data. The unrisked volume estimate is multiplied by the exploration chance of success percentage to give a recoverable resource volume which could be discovered
SAGE	Scottish Area Gas Evacuation system - gas transportation and processing system at St Fergus
SEAL	Shearwater Elgin Area Line, transporting gas from CNS hubs to Bacton

Source: Westwood Energy Atlas

Glossary of terms

Term	Meaning
SEGAL	Shell–Esso Gas and Associated Liquids system - gas transportation and processing system at St Fergus
SEGAL FGL	Fulmar Gas Line - CNS gas pipeline feeding into the SEGAL system
SEGAL FLAGS	Far North Liquids and Associated Gas System - NNS gas pipeline feeding into SEGAL system
SGP	Shetland Gas Plant at Sullom Voe, receiving Laggan–Tormore gas
SIRGE	Shetland Islands Regional Gas Export pipeline linking SGP to FUKA
SNS	Southern North Sea
SVT	Sullom Voe Terminal - major WoS oil and gas processing terminal
TEC	Transitional Energy Certificate - proposed replacement for licensing rounds under which unlicensed acreage could be awarded in on out-of-round basis, with additional restrictions compared to traditional licence rounds
Technical discovery	A well drilled into a reservoir that is deemed to have not encountered adequate quantities of oil/gas to support production. This may be due to insufficient volumes, technical challenges for economic recovery (e.g. rock properties, hydrocarbon properties, distance from infrastructure) or no longer lying on licenced acreage
Terminal	Receives liquids or gas exported from offshore hubs and provides end-of-line processing, storage and export or distribution
TGPP	Teesside Gas Processing Plant, operated by NSMP, which processes gas from Breagh and part of CATS throughput
Tie-back	Subsea connection linking a new field or satellite to an existing hub for processing and export
TPA	Tonnes Per Annum - used for LNG import/export capacity
UKCS	UK Continental Shelf - offshore area including the North Sea, West of Shetlands and Irish Sea
Unlicenced	Acreage which has never been part of a licence, or which was historically licenced but relinquished. Licences can be relinquished once fields have ceased production and being decommissioned, or when licence phases are complete and companies do not commit to the next licence phase
WOBBE Index	A measure of gas quality based on the amount of energy it delivers when burned, used to define the acceptable range of gas quality for the UK gas supply
Workover	To perform one or more of a variety of remedial operations on a producing well in efforts to enhance or increase production
WoS	West of Shetland
WOSPS	West of Shetland Pipeline System transporting associated gas from Clair/Schiehallion to SVT

Source: Westwood Energy Atlas

Disclaimer

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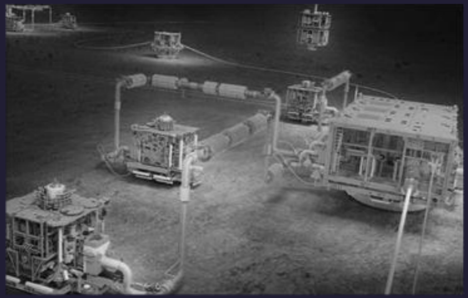

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