# Just Transition Review of the Scottish Energy Sector

Chapter 1 - a baseline review of the Oil and Gas sector in Scotland

**Reliance Restricted**

**06 September 2022**

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Please see Appendix D for a copy of our Transmittal letter, which summarises the purpose of this report, restrictions on its use and the scope of our work.

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# Abbreviations

| Abbreviation | Description | Abbreviation | Description |
|---|---|---|---|
| API | American Petroleum Institute | IPCC | Intergovernmental Panel on Climate Change |
| AQ | Air Quality | Mmboe/d | Millions of barrels of oil equivalent per day |
| AR6 WG1 | Assessment Report 6 Working Group 1 | $MtCO_2e$ | Million tonnes of carbon dioxide equivalent |
| BEIS | The Department for Business, Energy and Industrial Strategy | NAEI | National Atmospheric Emissions Inventory |
| boe | Barrel of oil equivalent | NNS | Northern North Sea |
| BRES | Business Register and Employment Survey | NOC's | National Oil Companies |
| CADR | Compound annual decline rate | NSTA | North Sea Transition Authority |
| Capex | Capital expenditure | NSTD | North Sea Transition Deal |
| CCC | Climate Change Committee | O&G | Oil and Gas |
| CCUS | Carbon Capture, Usage and Storage | OEUK | Offshore Energies UK |
| CNS | Central North Sea | ONS | The Office for National Statistics |
| $CO_2$ | Carbon dioxide | PGR | Production Gap Report |
| $CO_2eq/MJ$ | Carbon dioxide equivalent per megajoule | RBL | Reserve-base lending |
| CoP | Cessation of production | RFCT | Ring Fenced Corporation Tax |
| DERV | Diesel Engine Road Vehicle | RFES | Ring Fenced Expenditure Supplement |
| DPC | Development and Production Consent | ROW | Rest of the World |
| EBITDA | Earnings before Interest, Taxes, Depreciation, and Amortisation | rUK | Rest of the United Kingdom |
| EV | Electric Vehicle | SC | Supplementary Charge |
| EY | Ernst and Young LLP | ScotNS | Scottish North Sea |
| FID | Final Investment Decision | SG | The Scottish Government |
| FtF | EY's Fuelling the Future framework | UJV | Unincorporated joint venture |
| FPSO | Floating Production Storage and Offloading | UK | United Kingdom |
| GDP | Gross Domestic Product | UKCS | United Kingdom Continental Shelf |
| GHG | Greenhouse Gas | ULEV | Ultra-low emissions vehicle |
| $GtCO_2$ | Gigatonne of carbon dioxide equivalent | UN | United Nations |
| GVA | Gross Value Added | WACC | Weighted average cost of capital |
| ICE | Internal combustion engine | WoS | West of Shetland |
| IEA | International Energy Agency | | |

# 1 Executive Summary

# Scottish O&G production will decline and reserves will be increasingly hard to exploit

### Oil and Gas (O&G) production from the Scottish North Sea (ScotNS) will decline and by 2050 production levels are forecast to be minimal

- By 2050 production is forecast to fall to 0.1 Mmboe/d, 7% of 2019 levels.
- Between 2019 and 2050, cumulative production is forecast to be 7.7bn boe. The compound average rate of decline over this period is 7.8%.
- Any new projects will only slow the decline of production as these are likely to be smaller fields that will be exhausted more quickly.
- This forecast is based on data from O&G operators and is a best estimate of future production.

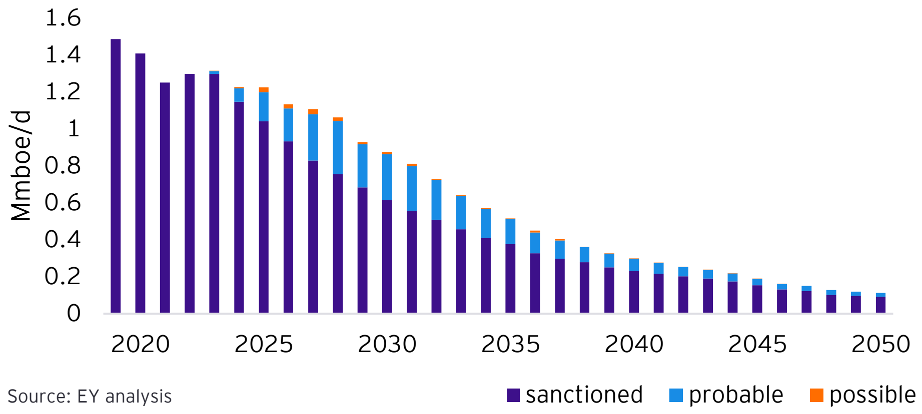
### The decline in production is unlikely to be steeper than currently forecast

- Forecast future production is not highly price-dependent, given that much of the necessary infrastructure exists, thereby reducing the extra cost of additional extraction, and the fact that a large proportion of future production is already sanctioned.
- Over 80% of future production will arise from existing sanctioned fields, with the remainder of forecasts coming from new developments (probable and possible projects).

### Higher prices could lead to more reserves being exploited, but the potential for further production is hard to quantify

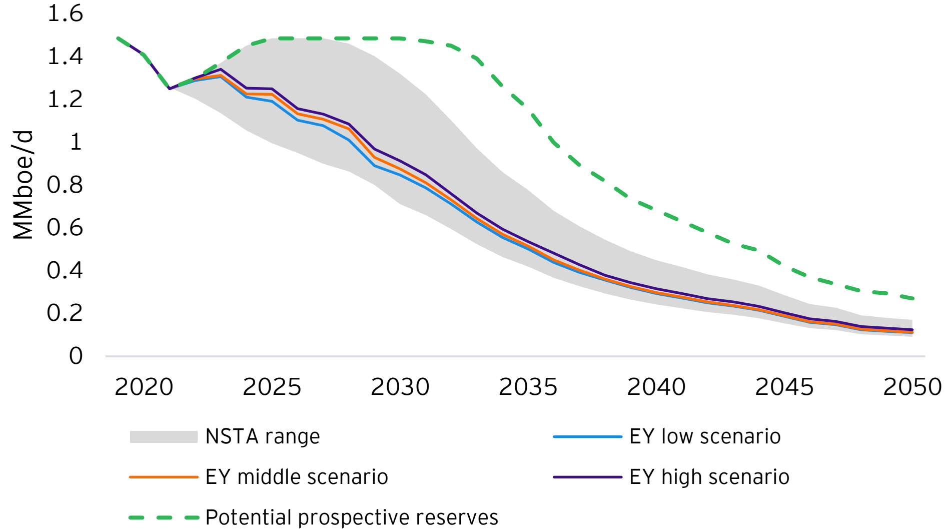
- The 2019 North Sea Transition Authority (NSTA) reserves analysis indicates that there are between 6.3bn and 11.7bn boe of reserves in the UK Continental Shelf (UKCS). This compares with our cumulative production forecast of 7.7bn boe.
- The NSTA asserts that there may be an additional undiscovered prospective resources of 7.6bn boe between now and 2050.
- Some of these prospective resources could be identified and exploited in higher price scenarios, but our data indicates that O&G companies are not currently planning to explore for these reserves.
- Future production levels will be dependent on a number of factors including O&G prices but also technical, regulatory and economic limitations to exploiting reserves.
- There may be some increase in production beyond our production forecast but it is unlikely that all potential reserves will be exploited.

### Hydrocarbons production in Scotland 2019 to 2050 medium case with delay scenario




Source: EY analysis

### Total hydrocarbons production (sanctioned, probable and possible) and alternative reserves illustration[1]




Source: EY analysis

[1] The chart includes estimates that illustrate how cumulative NSTA reserves could apply as a production trajectory. These have been developed to provide comparable production pathways that align with the EY scenarios.

# The economic footprint of Scottish O&G production is large and decline will impact the North East of Scotland negatively in the absence of a Just Transition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### The economic footprint of the ScotNS is large, particularly in the North East of Scotland

- 79,000 jobs were estimated to have been generated by Scotland's offshore O&G sector in 2019.
- These jobs are high value compared to the Scottish average, with an average wage of £88,000 for direct jobs, and £51,000 in the supply chain (indirect employment), compared to a Scottish average of £29,000.
- Of the 25,000 direct O&G jobs, 98% were located within Aberdeen City and Aberdeenshire.
- The industry is responsible for a total GVA of £18bn, equivalent to 10% of total Scottish GDP.

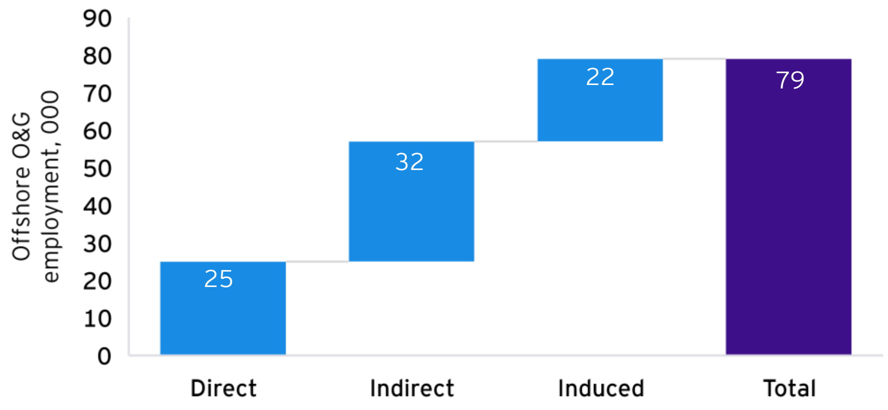
### The indirect jobs in the supply chain might be more important than these figures show

- These figures assume that the Scottish share of the supply chain is the same as the Scottish share of that industry within the UK, that is, 28%. This is a conservative assumption and the scale of jobs/GVA in the supply chain is likely be higher, particularly in Aberdeen, which means that the impact of decline would be correspondingly more severe.

### The forecast decline in employment and GVA is stark: from 79,000 to 44,000 jobs by 2030, creating a challenge for a Just Transition

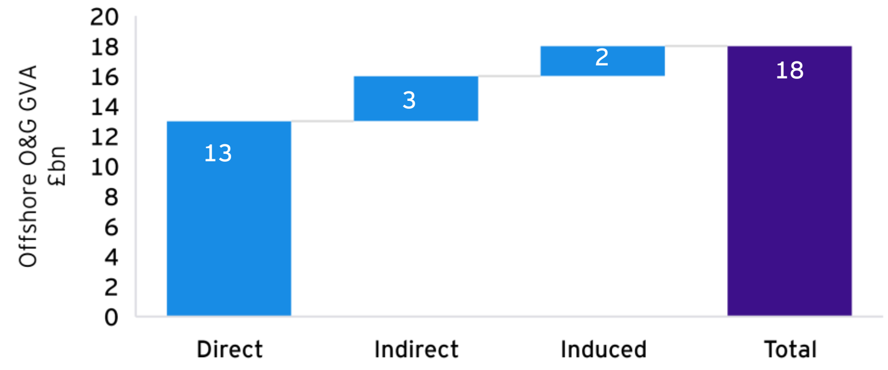
- The decline in the jobs and GVA that will accompany the forecast decline in production is signifciant. On our central estimate, production will be halved from current levels by the early 2030s, so economic dislocation will be a factor if renewables and other industries have not yet picked up to levels to compensate.
- The pace of change is likely to be rapid, and the export orientation of the industry means that domestic renewables may not supply equivalent employment within that timeframe.

**Employment contribution (2019)**




Source: EY analysis, BRES

**GVA contribution (2019)**




Source: EY analysis, ONS

Note – 2019 data has been used as this is the most recent year where a full picture is available for Scottish commodity balances. 2019 also depicts a more accurate reflection of trends over time, as the COVID-19 global pandemic affected global demand and supply in 2020 and 2021.

# Upstream O&G emissions are falling and future reductions will be primarily driven by declining production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### ScotNS O&G production is a significant source of GHG emissions

- Although emissions arising from upstream O&G production in the ScotNS represent less than 10% of the total emissions produced from a barrel of oil, the UKCS has produced significant levels of GHG emissions, especially in recent decades.
- The total UK upstream industry emissions peaked in 1996 at 29 MtCO2e, before falling to 17 MtCO2e. This represents 4% of total UK GHG emissions but, if split pro rata, the Scottish share would represent over 30% of Scottish emissions.
- GHG emissions arising from equipment such as oil platforms are complex and vary according to a range of factors such as age, how it is powered and other operational factors.

### Upstream GHG emissions (Scope 1) arising from the ScotNS are lower than global averages, and rank lower than some other offshore producing nations

- The geology, infrastructure and the operating environment result in a varied and complex emissions profile for the ScotNS, but the introduction of industry emissions reduction targets through the North Sea Transition Deal (NSTD) creates an opportunity to reduce the industry's carbon footprint further.
- Future ScotNS GHG emissions will continue to reduce with falling production levels and the introduction of carbon reduction activities.

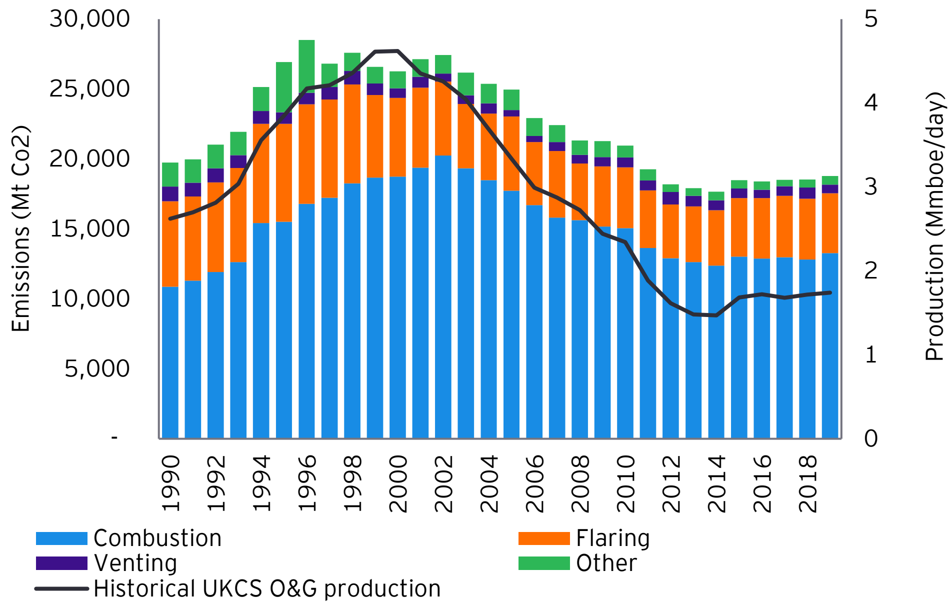
### The UKCS has absolute GHG emission reduction targets, but this will not necessarily result in a major 'per barrel' reduction in emissions

- The NSTD aims to make an absolute reduction in GHG emissions from UK O&G production of 10% by 2025, 25% by 2027 and 50% by 2030 (against a baseline of emissions in 2018).
- The NSTD contains commitments to reduce GHG emissions, such as those from venting and flaring and exploring investment in platform electrification, but these are not made on a per barrel basis. This means that the natural decline in the ScotNS will be a large factor to the decline in total emissions.

### ScotNS emission reduction activity is possible but comes with operational and commercial challenges

- Norway, with comparable geology and operating conditions, has pushed the electrification of platforms and has also benefitted from a decarbonised onshore electrical grid, historical carbon taxes, and longer dated reserves.
- Large scale investment is needed to decarbonise the industry in the UK. Investment is needed in offshore renewable resources, equipment, technology and infrastructure to enable large scale electrification.
- The investment case for platform electrification is not clear, given the costs and the expected useful life of existing platforms.

### Historical UK upstream GHG emissions



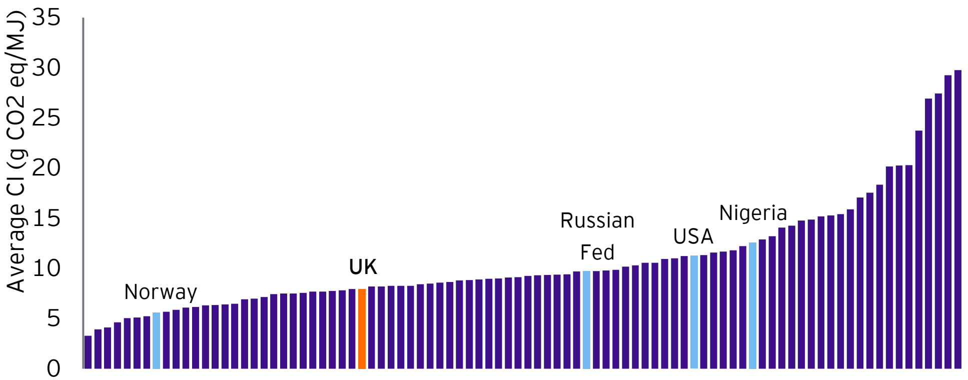

Source: NAEI, NSTA

# Internationally, the UK is in the mid range for emissions, and increasing imports could raise emissions if Scotland's demand for O&G remains constant

## GHG emissions

- The commitments made in the NSTD demonstrate that the UK O&G industry is taking steps towards emissions abatement activity, although comparison to Norway, which has similar geology and operating conditions, indicates there is still some distance to go.
- However, comparison with global O&G producers shows that the UK's carbon intensity levels are lower than the global average and lower than many other offshore O&G producing basins.
- It is therefore important to recognise that, if Scotland's demand profiles for O&G remain constant and ScotNS production declines, then Scotland's overall O&G-related GHG emissions would rise. This is because domestic demand would have to be met through an increase in imports from countries with higher carbon intensity levels than the UK.

### Estimated global upstream crude oil carbon intensity (2015)



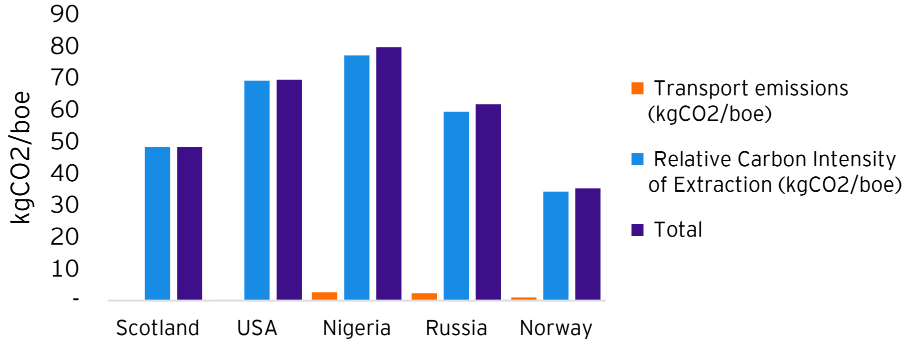

Source: Stanford University

## GHG implications of shifting production patterns

- Trading conditions on the global oil market change daily, meaning that Scotland does not consistently import from the same countries. However, on average, imported crude oil comes from areas with a higher carbon intensity of extraction than the ScotNS. In 2019 Scotland's largest imports of crude oil came from Nigeria, Norway, Russia and the USA.

- Transport emissions associated with shipping overseas also need to be considered, meaning on average imports have higher GHG emissions than ScotNS crude oil, which does not need to travel far to get to refinery gates.
- Chapter 2 will focus on demand drivers, and expected future demand is currently unknown. GHG emissions would likely increase if demand remains constant and imports have to increase to replace a decline in ScotNS production. However, Scotland already imports c70% of the crude oil used at Grangemouth refinery, so the effect of this is unlikely to be significant until the later in the period of decline.
- At the UK level, the need to import more will be felt sooner, potentially raising overall emissions.

### Relative emissions of imports




Source: Stanford University, IEA, MIT, Sea Distances Org

## Further considerations

- Given the lower carbon intensity of UKCS oil relative to the UK's main sources of imports, a managed transition could be expected to result in a better GHG emission position than a sudden cessation of O&G production, especially when combined with ongoing decarbonisation of ScotNS production.
- Transition could increase overall GHG emissions for Scottish demand – but the pattern of importing and exporting is currently optimised by price rather than emissions.

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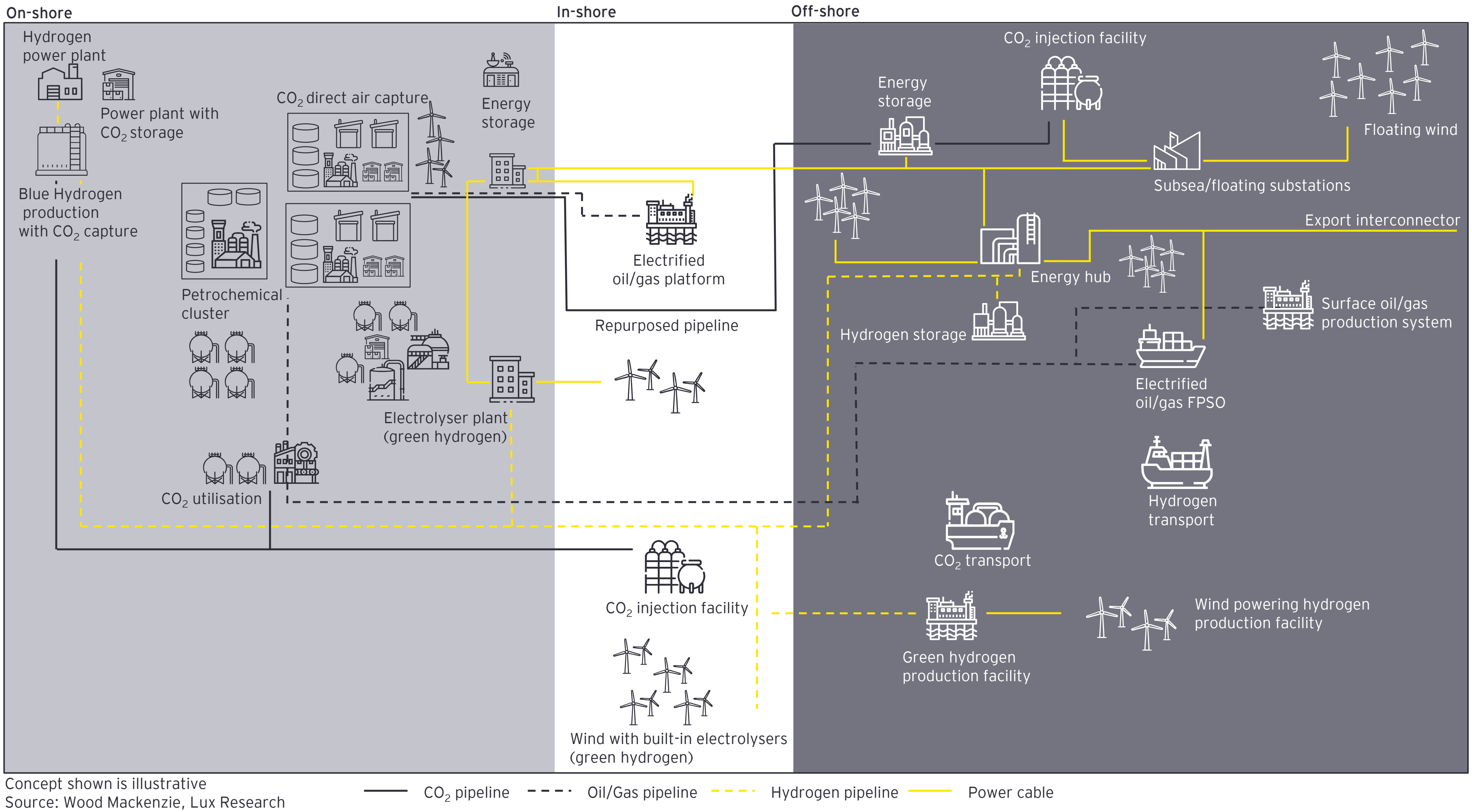
# There is potential for the ScotNS to become an integrated energy basin ecosystem (below), with renewables, hydrogen, O&G and CCUS linked together to produce net zero energy




Concept shown is illustrative
Source: Wood Mackenzie, Lux Research

The illustration incorporates a number of low carbon technologies that are currently being developed. Further information on the integrated energy basin can be found in section 6.

# Infrastructure re-use for transition is possible but challenging – timing and commodity pricing will be significant hurdles to repurposing, as will aligning to emerging technologies

### It is challenging to plan for the re-use of O&G assets as their value is directly linked to prevailing commodity prices, which have been particularly volatile in recent years

- There is a significant volume of O&G infrastructure in ScotNS but it is difficult to determine the total asset value. This is directly linked to the assets' future use and associated cashflows, which are unpredictable, varying as they do with volatile commodity prices, meaning the profitable life of an asset can extend without warning.

### Decommissioning liabilities are substantial and some of these could be deferred through re-use – but current users may need to be compensated

- The energy transition offers potentially significant opportunities for O&G infrastructure owners. The OEUK estimates that decommissioning spend in the ScotNS could reach £16.6bn over the next decade, £13.1bn of which relates to assets in the ScotNS. The development of greener ways to decommission and the identification of circular economy efficiencies offer the chance to create substantial economic value.

### The ability to re-use infrastructure varies across different asset types and will depend on the development of alternative technologies in the ScotNS

- The ScotNS O&G infrastructure can facilitate the transition to an integrated energy basin, as it offers physical links to offshore sites that can be re-purposed and re-used to deliver the net zero economy. A number of asset types appear to be viable or potentially viable for re-use, including Reservoirs, Platforms and floating production storage and offloading (FPSO) units, Pipelines and Onshore Terminal sites.
- Energy transition sectors which offer near-term uses for existing infrastructure are CCUS and hydrogen. In the future, a move to more integrated energy systems, such as offshore green hydrogen production (potentially using platforms) and hydrogen storage to deal with intermittency, could unlock further opportunities.

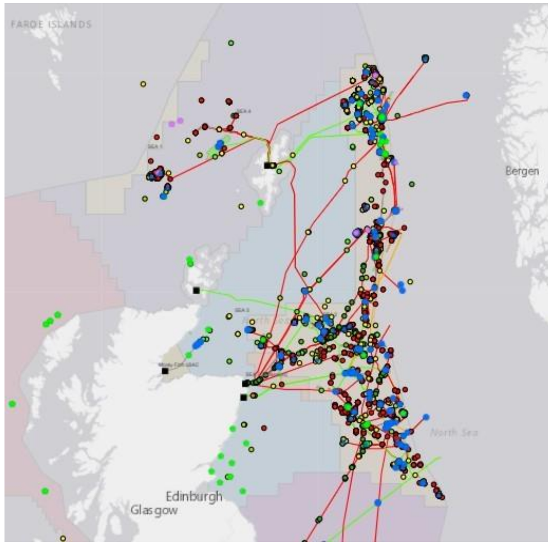
### But there are barriers to infrastructure re-use that need to be overcome

- The whole-life business case of re-use can be weak as it can lead to higher operating costs because older assets are not purpose-built and require more maintenance.
- The O&G industry's complex ownership and commercial model presents a challenge for both decommissioning and re-use/repurposing. However, such complexity is common in the current operations on the ScotNS, and many companies are themselves transitioning from O&G to low carbon businesses.
- Re-use requires assets to be no longer used in O&G production. Costs will be associated with preserving assets for future re-use, and these are likely to increase if there is a longer period between the cessation of production and re-use. Timing and coordination will be critical.

### Re-use of infrastructure can also support the supply chain and help retain high value jobs

- The growing offshore sectors can draw on the Scottish O&G industry's world class supply chain concentration of skills, expertise, capabilities, and experience of delivery in one of the world's harshest marine environments, backed by the country's extensive ports and aviation infrastructure. These areas of the industry are themselves evolving to support the developing sectors.
- The re-purposing of existing ScotNS infrastructure could enable the accelerated rollout of emerging industries. As a mature basin, the chance to re-purpose its assets is occurring sooner than in younger hydrocarbon basins, meaning that successful re-use could secure Scotland world leader status in emerging sectors such as CCUS and hydrogen.

### The extent of O&G infrastructure in the ScotNS




Offshore platforms = blue dots
Wellheads = red dots

Pipelines
- Red line = Gas,
- Green line = Oil,
- Orange line = mixed hydrocarbons

Source: NSTA maps, https://NSTAuthority.maps.arcgis.com

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# Relationships and trade flows with rUK and the ROW will change with decline of ScotNS production levels

### Scotland imports O&G despite production volumes exceeding demand.

- Scottish demand has never been the primary driver of ScotNS 'indigenous' production. The majority of Scottish O&G production is exported to the UK and further afield. For scale, total Scottish consumption of O&G in 2019 was only 20% of total Scottish O&G production volume, with a significant portion of the O&G consumed being imported rather than coming from ScotNS fields.
- 65% of Scottish demand for refined oil products in Scotland is met by Grangemouth, Scotland's only refinery. Grangemouth's capacity could meet all of Scottish demand, but it has historically exported around 40% of its output due to external economic drivers in the wider global oil market. Scotland also imports smaller volumes of refined oil products from the rUK as the road fuel consumed in the North of Scotland is supplied by English refineries via exchange agreements.
- It can be more economically beneficial for Grangemouth to import to meet domestic demand while oil originally produced in the ScotNS is exported.
- The natural gas used in Scotland comes from a combination of ScotNS production and imports from Norway. Scotland imported gas in 2019, despite ScotNS production being 2.5 times Scottish demand. This is due to the layout of existing infrastructure which means that some pipes run from ScotNS directly to rUK gas terminals, while some Norwegian fields connect directly to St Fergus gas terminal in the North East of Scotland.

### The relationship with rUK is changing as production falls.

- Oil exports to rUK have fallen over time. The ScotNS no longer fulfils most of the demand for oil in the rUK, although this flow is still significant.
- Exports, including to the rUK, have fallen more significantly than domestic consumption of O&G products.
- The shift in gas is more striking. Historically, the ScotNS supplied most of the UK grid, but now the rUK is supplied largely from other sources and Scotland now also imports gas, particularly during periods of high demand as the National Grid balances demand.

### Domestic demand has also shifted

- Scottish demand for gas has steadily increased since the 1990s as gas has replaced coal in electricity generation. This has been a factor supporting improvements in air quality and a reduction in GHG emissions.
- Despite declining production, demand from the transport industry, particularly road fuel, has remained steady over the last 20 years, as has demand for O&G in heating. According to the 2020 Annual Energy Statement, ~75% of Scotland's energy consumption came from O&G, putting Scotland behind its target to deliver the equivalent of 50% of total energy consumption from renewable sources by 2030.
- Scottish demand for O&G should decline as SG net-zero policies come into effect, such as electric vehicle rollout and low carbon heating initiatives. However, should low carbon replacements be insufficient to meet Scotland's energy demands, any continuing reliance on O&G could result in increased imports as domestic O&G production continues to decline.

### Scotland is still exporting widely to the rest of the world given global demand for ScotNS oil.

- In 2019, 40% of Grangemouth's production of oil and oil products was exported, although this has been scaled back significantly since the mothballing of one crude distillation unit (CDU) and a fluidised catalytic converter (FCC) unit at the site in 2021.
- Scotland exported 93% of Scottish production of crude oil in 2019. Export levels are determined by price, demand, and where trading conditions mean this is the most profitable option. Export destinations have historically been further afield, resulting in greater GHG emissions due to the distance of oil transportation.
- Gas exports are predominantly to rUK and, to a lesser extent, the Republic of Ireland due to the infrastructure of the National Grid and fact that pipelines from ScotNS gas fields directly supply rUK.

### Energy security requires steady trade flows.

- Scotland has no gas storage and very little oil storage. Coupled with global competition, this puts greater pressure on energy security, although Scotland does have direct physical interlinks with Norwegian gas supply fields, as well as existing trade agreements for liquefied natural gas (LNG) landing at St Fergus Gas Terminal. While this helps with energy security concerns regarding supply, increased imports can result in increased prices.
- Scottish (and UK) energy security is more reliant on a diversity of sources of O&G and a degree of domestic production than storage, and any particular source (e.g. Russia) can be replaced rapidly. Expanding storage to cover even a short time period would be extremely expensive.

*Note: all figures in this page have been taken from SG's - Physical commodity balances of oil, gas and petroleum products, based on BEIS' Digest of UK Energy Statistics (DUKES) 2021 - GOV.UK (www.gov.uk)*

# Scotland's O&G flows in 2019 clearly illustrate Scotland's position as a net exporter, as well as the scale of ScotNS production compared to Scottish consumption levels


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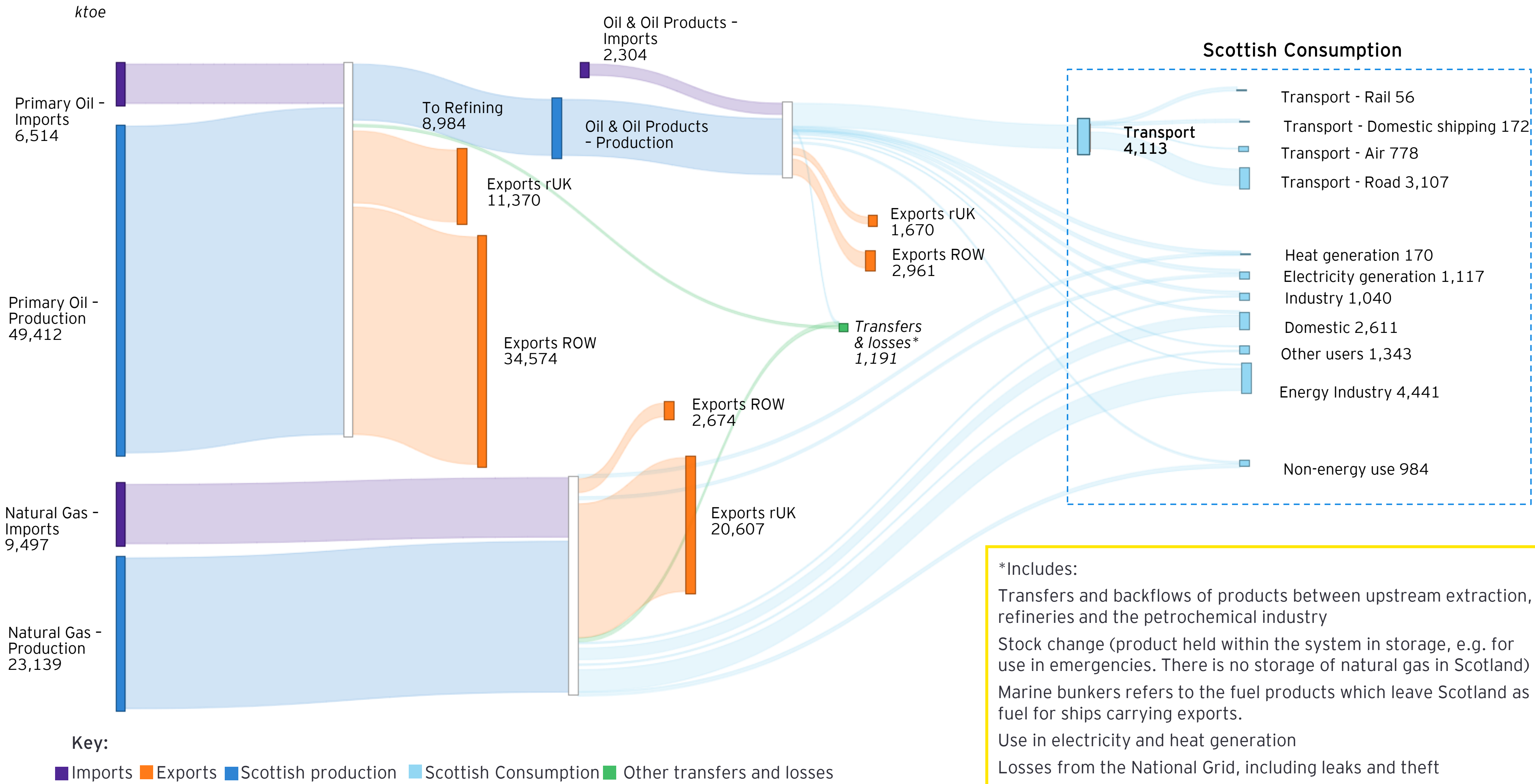


*Includes:

Transfers and backflows of products between upstream extraction, refineries and the petrochemical industry

Stock change (product held within the system in storage, e.g. for use in emergencies. There is no storage of natural gas in Scotland)

Marine bunkers refers to the fuel products which leave Scotland as fuel for ships carrying exports.

Use in electricity and heat generation

Losses from the National Grid, including leaks and theft

*Source: SG - Physical commodity balances of oil, gas and petroleum products*
*Digest of UK Energy Statistics (DUKES) 2021 - GOV.UK (www.gov.uk) (commodity balances)*

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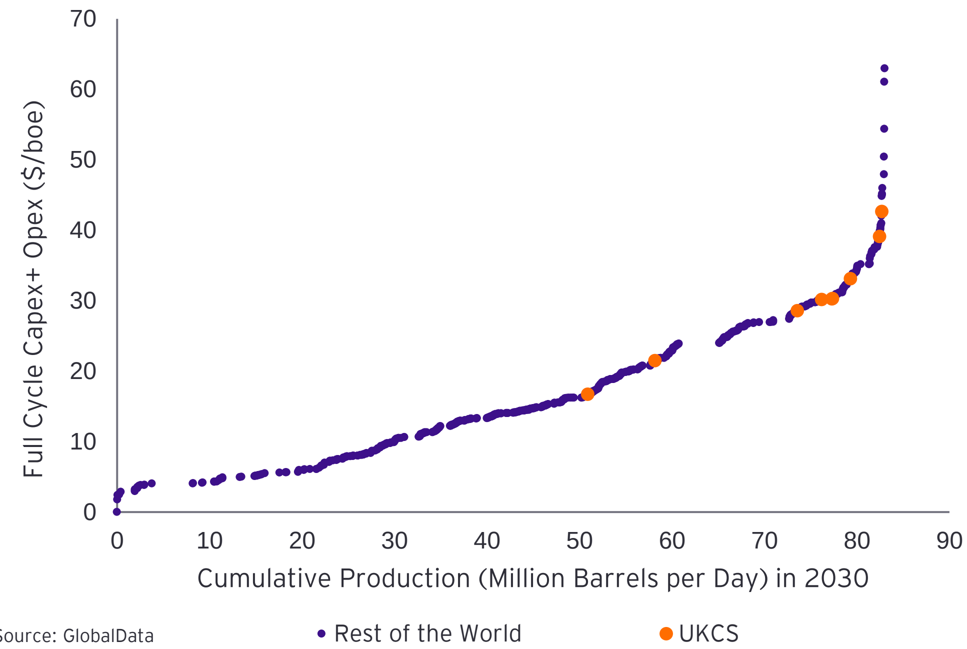
# Scotland is an attractive jurisdiction for investment but the ScotNS still faces a decline because of dwindling and difficult to extract reserves and cost

- The UKCS has been an important part of the global O&G industry since the 1960s and, despite production peaking in the early 2000s, it continues to attract investors. However, with falling production levels and limited future prospective resources, its role as a global O&G producing basin is expected to diminish.
- The ScotNS has been an attractive jurisdiction in regulatory and taxation terms which has helped it compete for global capital. The UK's commercial, regulatory and fiscal environment has historically been regarded as relatively stable, allowing for predictable returns, an investor-friendly environment and generally attractive conditions for investors. In 2016, in an effort to stimulate more investment in the UKCS, UKG made the fiscal regime more generous to support the development of offshore fields. However, the introduction of the Energy (Oil and Gas) Profits Levy (EPL) in 2022 has resulted in a new tax regime for the O&G industry, resulting in a less stable investment picture for the UKCS (and ScotNS).
- The ScotNS benefits from geographical proximity to an established market in Europe and the security of local demand, making it a relatively attractive location for O&G production.
- The maturity of the ScotNS also means that investors can rely on its sophisticated infrastructure landscape and access a world-class supply chain. Future supply chain capacity will be impacted by several factors, but recent downturns in commodity prices has reduced capacity.

### But the physical nature of reserves presents challenges for investment.

- The geology and geography of remaining UKCS reserves makes their exploitation harder and more expensive. Global costs of production present a complex picture, but the cost of production in the UK is higher than other basins. As a result, the UK has seen a slowdown in investment, which is reflected in the production forecast.
- As the chart shows, the cost of the ScotNS fields on a 'whole-life' basis tends to be higher than other basins globally, in other words, it is more expensive to extract O&G in the ScotNS than other global basins (although there is significant variance on a field by field basis). This is likely to be more marked for new discoveries where the infrastructure costs are similar to existing fields but the longevity of their economic life is shorter.

### UKCS vs. Rest of the World cost curve




Source: GlobalData

Since the time of writing this report O&G prices have been significantly impacted by war in Ukraine and the economic consequences and duration of this geopolitical risk cannot be fully predicted. Although we do not expect it to alter the underlying conclusions, any period of prolonged high prices will have an impact on future production forecasts. Historical geopolitical events have impacted oil prices but other factors, such as the response from other O&G producing nations, will also need to be considered.

Following the Russian invasion of Ukraine, the UKG announced that it would phase out all imports of Russian hydrocarbons by the end of 2022. The UK has the ability to move away from Russian hydrocarbons relatively quickly and easily compared to other European countries that have historically had a greater share of hydrocarbon imports from Russia. Despite this, the UK could still be indirectly impacted through price levels and price volatility.

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# Policymakers will need to actively manage the Just Transition in terms of the demand side and new industries, as well as supporting the North East's economic transition

### The production forecast shows that the timing of energy transition will be crucial

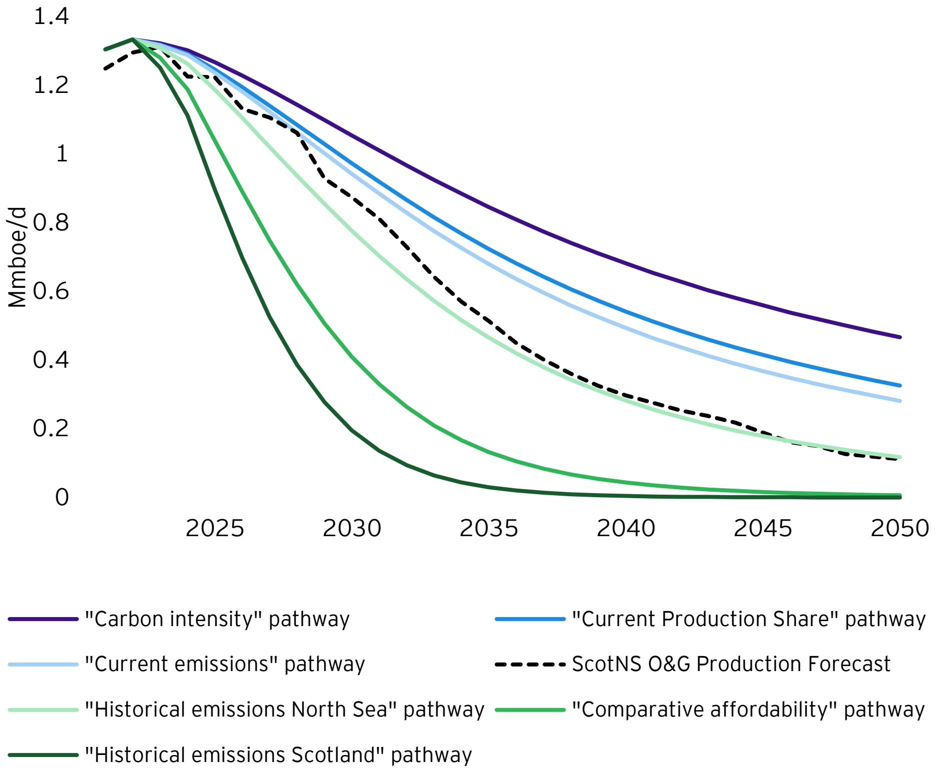
- The figure on the right compares the ScotNS O&G production forecast established in this report with EY's Fuelling the Future (FtF) scenarios modelling developed in Section 13. The scenarios illustrates the potential routes for a Scottish Just Transition. The scenarios were derived by assuming that Scotland's production serves a constant portion of global demand but we note that alternative outcomes may arise given the many other factors in play including oil prices, cost and regulation. Section 13 provides more information on the range of potential scenarios and their implications.
- The analysis highlights that a range of outcomes are possible, with some pathways falling more quickly than the ScotNS production forecast, while others do not.
- The two International Energy Agency (IEA) pathways provide further context and benchmarks for these potential pathways.

### As production falls in ScotNS, a number of factors will become significant and difficult to manage

- Continued reliance on O&G. Although growing, renewables are currently a relatively small part of the overall energy mix, and understanding and addressing demand drivers for O&G is necessary.
- GHG emissions could increase. Without addressing the demand side, greater levels of importing could see increased emissions in the later stages of production decline.
- The O&G sector generates a lot of high quality employment and Scotland, specifically in the North East, and a Just Transition will need to see new quality jobs in other sectors.
- Transition to an integrated energy basin will require new business models at large scale – particularly in CCUS and hydrogen.
- Macroeconomic considerations. Tax receipts from O&G sector will reduce (albeit to UK Government) while the need for subsidy support to stand up new industries will increase.

In Chapter 3 we explore the potential positive impact of transitioning faster than the forecast ScotNS O&G Production Pathway.

### Scotland's potential production pathways




*Source: EY analysis, NSTA stewardship survey*

# 2 Introduction and background

# Introduction, context and scope



## Background and Context

The climate change emergency and the need for a Just Transition programme in response requires the largest re-deployment of capital and step-change in behaviours since the industrial revolution, and the Scottish Government (SG) has put this at the forefront of its policy objectives. The draft SG and Scottish Green Party's Shared Policy Programme, published on 20 August 2021, states that, in order to achieve a Just Transition, it is crucial to baseline North Sea O&G production against the backdrop of the global climate emergency and Scotland's economic security and wellbeing.

We have been commissioned to undertake this review of the O&G sector in Scotland to support both policy development and the creation of a refreshed Scottish Energy Strategy and Just Transition Plan.

## Purpose of this report

This report represents the first chapter in a multi-phase exercise. Any subsequent policy decisions will be informed by the full package of analysis completed in Chapter 3 and not just the conclusions of this report.

The scope of this report, which is Chapter 1, is as follows:

- To provide a detailed overview of O&G production in the ScotNS today. This will include: production and proven reserves, economic and financial metrics, current investments and scale of employment, including associated distribution supply chains, supported by production.
- To explore trends in greenhouse gas emissions and emissions intensity of O&G production in the ScotNS.
- To provide a detailed infrastructure summary explaining the infrastructure that exists in the ScotNS and how this is used, or could be used, as part of an integrated energy basin. This will explain in detail how O&G production is transported and brought onshore.
- To provide a detailed overview, along with analysis and exposition, of imports of oil, gas and related fuel products into Scotland. This includes from rUK and ROW. The analysis will explore sources of imports, product type, relative emissions intensity (including emissions from product transport), function and purpose.
- To provide a detailed description of the intermediate processes to refine and produce fuel products and petrochemicals within Scotland, including an explanation of the balance and mix of domestically produced and imported products.
- To describe and quantify the end-use of O&G products within the Scottish energy system, clearly mapping the flows from indigenous Scottish production and imports.
- To provide a detailed overview, explaining, describing and quantifying the O&G products which are exported from Scotland, including to rUK and ROW. This will clearly map the flows from Scottish production and imports and consider transport-related emissions.
- To provide narrative and analysis which sets the Scottish sector in a global context and provides relevant comparison and benchmarking against other O&G producing basins. In particular, the comparison will focus on emissions intensities, but also investment drivers and barriers, as well as any advantages or disadvantages for the Scottish sector.
- An assessment of the production levels consistent with Scotland's domestic climate change targets.

## Report limitations

At the time of writing this report O&G prices have been significantly impacted by war in Ukraine and the full economic consequences of this geopolitical risk cannot be fully predicted. Although we do not expect it to alter the underlying conclusions, any period of prolonged high prices will have an impact on future production forecasts. Historical geopolitical events have impacted oil prices but other factors, such as the response from other O&G producing nations will also need to be considered.

This report has been written to provide a baseline review of the Scottish O&G sector to support Scottish policy development and the new Scottish Energy Strategy. We acknowledge the reality that Scotland is a member of the United Kingdom and part of an integrated UK O&G sector, and that any production, imports or exports is done at a UK level. However, given the context and purpose of the report, it has been written entirely from a Scottish perspective. There are a number of ways in which Scottish data could be separated from rUK, including by geography, % of population and GDP. The methodology by which the Scottish imports, exports, production and demand figures have been split out is discussed in Appendix A – Methodology note for sections 7-11.

# The Scottish Energy System

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## Scottish O&G Overview

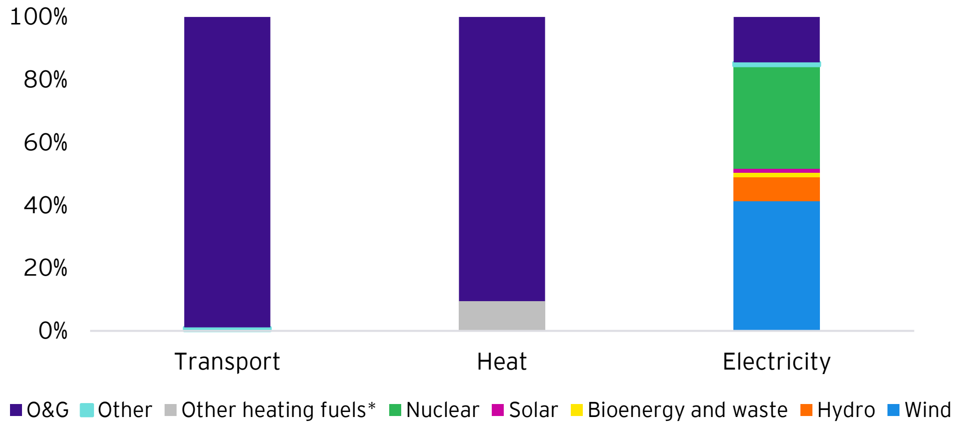
O&G has played a critical role in meeting both Scotland's and the wider UK's energy needs. Although the industry dates back to the 19th century, its rapid development occurred in the 1970s with the discovery of significant O&G fields in the North Sea. Since then the industry has grown to be one of Scotland and the UK's largest industrial sectors.

The UK Government is responsible for the fiscal regime and regulation of the O&G industry. The industry's contribution to the UK and Scottish economies has been significant. This can be measured not only in contributions to UK tax revenues, but also the creation of jobs, economic output and the creation of a world-class supply chain. Additionally, the industry has also supported evolving domestic energy demands.

The industry has had a significant role in the development of Aberdeen as it became the focal point for ScotNS O&G. The city is home to several large O&G companies and has been transformed into a global centre for O&G expertise.

O&G continues to account for the majority of Scotland's energy consumption. According to the 2019 Annual Energy Statement, O&G made up 78% of total energy consumption, 91% of all heat demand (both domestic and industrial) and almost all energy consumption in transport.

### The Scottish Energy System




* Other heating fuel sources include electricity, solid mineral fuels and biomass

*Source: Annual energy statement 2019 - gov.scot (www.gov.scot) Scottish Energy Statistics Hub – Proportion of electricity consumption by fuel Scottish Energy Statistics Hub – Number of ultra low emission vehicles licenced*

### Electricity

Electricity accounts for just over a fifth of Scotland's total energy consumption. In 2021, 14.4% of electricity consumed in Scotland came from O&G, 51.6% from renewables and 32.8% from nuclear. Scotland generates more electricity than it consumes, with the surplus being exported. In 2020 there was a net export of 19.3TWh of electricity, Scotland's highest to date. This was due in part to record renewable electricity generation, and to reduced Scottish demand as a result of the COVID-19 pandemic. Net exports dropped to 16TWh in 2021. The mix of fuel sources for generation is broadly the same as consumption, with the majority of Scotland's renewable electricity generation coming from onshore wind.

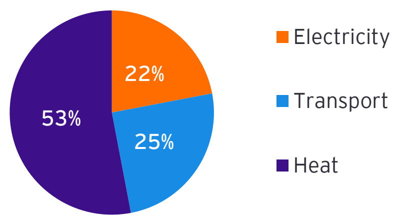
### Transport

Transport accounts for roughly a quarter of Scotland's total energy consumption. Given its historic dependency on O&G for fuel, the transport sector is one of the key focuses in the transition to a net zero Scotland, with a particular need to address road transport. SG has various initiatives in place which aim to phase out new petrol and diesel cars and vans, to be replaced by ULEVs in 2030. As of June 2021, there were 34,170 ULEVs licensed in Scotland, up 158% from June 2019. Although growth has been rapid, ULEVs only make up 1.1% of all road vehicles licensed in Scotland and transport continues to be heavily dependent on O&G fuel sources. As of October 2021, there were 2,676 public EV charge points and 684 rapid chargers in Scotland.

### Heat

Heating homes and businesses accounts for just over half of Scotland's total energy consumption. Since coal production ceased in 2016, O&G has accounted for 91% of all heat demand (both domestic and industrial) with almost all industry and approximately 79% of Scotland's homes relying on mains gas. According to OfGem, 13% of remaining properties use electrical heating systems, predominantly in urban areas, and the remaining households use other non-gas heating fuels, such as district heating, heating oil, liquid petroleum gas (LPG) or solid fuels. The latter are more common in remote rural areas and not regulated in the same way as the gas and electricity markets, meaning the exact usage is less clear.

### The Scottish Energy System – Consumption by Sector



# The Global Climate Emergency and Opportunities



## The global climate emergency and the need for change

Although the O&G's economic contributions are well publicised, the global climate emergency has shone a spotlight on the industry and its future role in Scotland. Scotland's ambitious climate change targets are stated in The Climate Change (Scotland) Act 2019, which sets targets to reduce Scotland's emissions of all GHGs to net-zero by 2045. The Act also established interim reduction targets of 56% by 2020, 75% by 2030 and 90% by 2040 (with 1990 as baseline for emissions). This is a clear demonstration of Scotland's commitment to the 1.5 degree goal of the Paris Agreement, the legally binding international treaty on climate change.

This energy transition presents opportunities and challenges for the sector. SG views this as an opportunity to develop new energy sectors in Scotland based on net-zero investments, that will maximise national and global opportunities and taken advantage of the skills and experience of the O&G industry.

Many traditional O&G companies have already diversified their offerings away from upstream O&G; for example, Shell and BP are just two of the major energy players to bid in the Scotwind auction for developing offshore wind. Not only does this create more diverse and resilient business models, but it will also allow businesses to embrace new renewable energy opportunities. Recent national and international incentives have resulted in a huge growth of renewables and other low-carbon alternatives to traditional fossil fuels.

## Opportunities for Scotland

The opportunities created by the energy transition are significant, and the creation of an integrated energy basin in the ScotNS and the ability to transition the skills and expertise from the O&G industry into new sectors is clear. For example, there is global interest in the development of hydrogen as a future driver of a decarbonised energy system, and initial Scottish trials to blend hydrogen into the existing UK National Grid natural gas network have already been hailed a success.

There are significant opportunities in Carbon Capture Utilisation and Storage (CCUS) which also present an interesting prospect to utilise the vast storage potential created by the geology and existing O&G infrastructure in the ScotNS.

Importantly, onshore and offshore renewables will also play a fundamental role in helping Scotland meet its net zero targets.

We will discuss the opportunities for Scotland in further detail in Chapters 2 and 3. These reports will explore the costs associated with the alternative technologies, as well as the impact these opportunities will have on Scottish jobs and GVA. In terms of environmental impact, we will explore the expected impact of and reliance on CCUS for negative emissions later in the transition, as highlighted in the IPCC WG3 report.

# 3 Scottish O&G production forecast

# Scottish North Sea production forecast

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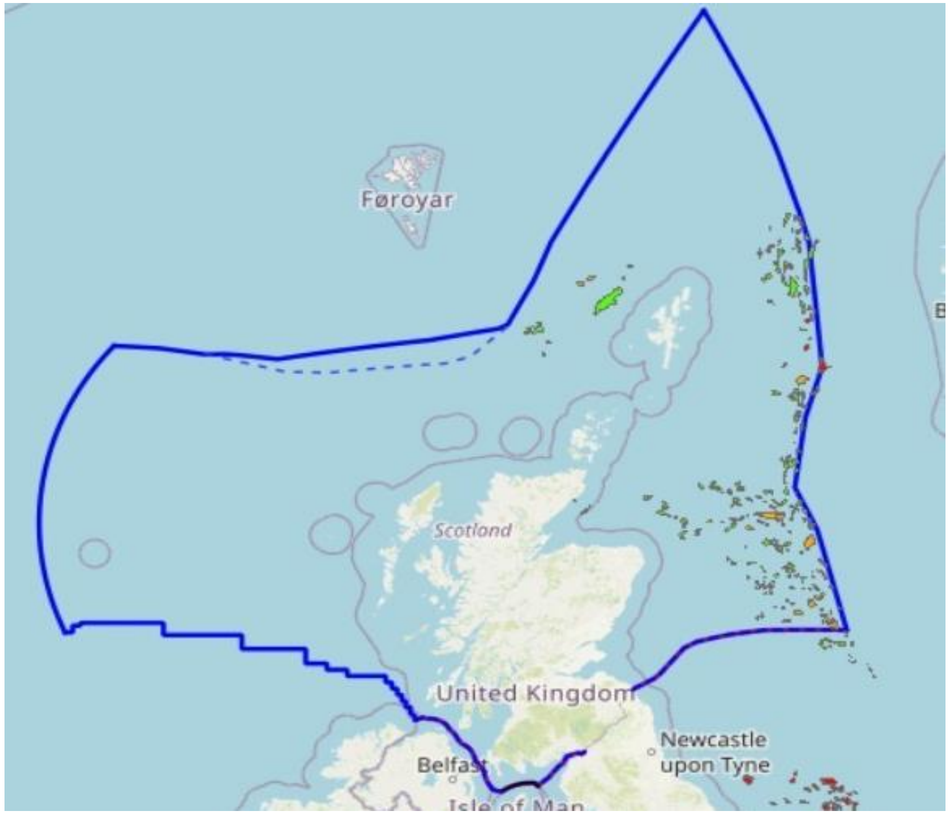
## Introduction

This section provides a detailed outlook of the anticipated O&G production from the ScotNS. It will also explore economic and financial metrics, the scale of employment from the ScotNS and the impact on the Scottish supply chain. The projections and estimates are a valuable tool to understand the likely pace at which the Just Transition will have to proceed to mitigate risks to employment in Scotland.




Source: marine.gov.scot

## What we mean by the "Scottish North Sea"

The UKCS is not allocated between the UK's constituent countries and different definitions for the ScotNS exist. However, for the purpose of this report we have followed the methodology that assumes the Scottish portion of the UKCS are based on activities within the Scottish adjacent waters boundary. This was defined during the devolution of fisheries management policy and is described in the Scottish Adjacent Waters Boundaries Order (1999). Other definitions may exist that present alternative perspectives on Scottish production, however, this definition follows existing SG practice and is used as a basis for the Scottish O&G production statistics in this review.

## ScotNS production forecast

Our production analysis is based on independent research commissioned by EY and provided by leading O&G academics. This research used anonymised data from the North Sea Transition Authority (NSTA) Asset Stewardship Survey for 2019. The survey includes operators' best estimate for hydrocarbons production as well as capital, operating and decommissioning expenditure.

The analysis covers approximately 80% of the sanctioned, probable and possible fields and incremental projects. The information for remaining fields and projects not included in the NSTA data is supplemented by independent estimates.

Total production levels are given in barrels of oil equivalent (boe). Sanctioned projects include those fields that are approved by the NSTA, and probable and possible projects include additional O&G fields where the viability of these fields is being considered by the NSTA and operators. This category includes fields such as Cambo, but does not include undiscovered fields or reserves which are currently regarded as not technically or commercially recoverable. Therefore the forecast does not represent the maximum possible economic production forecast.

The independent research also estimated the expenditure and investment in the ScotNS as well as estimating potential tax receipts attributable to the industry.

### Key assumption

The Scottish North Sea is defined by the Scottish Adjacent Waters Boundary Order (1999).

1. 2019 used as baseline year, as this is latest year of available data for Scottish GVA and employment by detailed SIC codes. In addition, 2019 is latest full year not impacted by COVID-19.
2. Gross Value Added (GVA) is a measure of economic activity which can be viewed as the incremental contribution to Gross Domestic Product (GDP). It therefore provides a useful measure for understanding the economic contribution made by particular industries, such as Scottish O&G.

# Methodology and assumptions



## Production forecast methodology and assumptions

The following assumptions underpin the production outlook:

- The analysis includes all hydrocarbon production, commonly referred to as "O&G" in this report.
- All fields and projects considered in the analysis are within the ScotNS. The economic modelling is based on 249 sanctioned O&G fields, 18 probable and possible fields and 59 probable and possible incremental projects to existing fields.
- The forecast does not account for prospective reserves or future discoveries. The forecast is conditioned on the assumption that there are no new licences for exploration.
- To obtain an expected value of below ground resources by the end of 2050, the independent analysis compares the production outlook against O&G reserves from the NSTA's 2021 UK O&G Reserves and Resources Report.
- Three real price scenarios are considered (below). The analysis assumes that the average prices will hold true until 2050, updated in line with inflation (real prices). It also assumes an exchange rate of £1 = $1.3214.

### Table 1: O&G price assumptions (2019)

| Scenario | Real Oil Price $/bbl | Real Gas Price pence/therm |
|---|---|---|
| Low | 50 | 50 |
| Medium | 65 | 80 |
| High | 80 | 120 |

Source: independent research commissioned by EY

- The analysis is based on the NSTA's asset Stewardship Survey for 2019 and it therefore the analysis does not reflect the impact of the 2020 price collapse. However, following this collapse prices have recovered during 2021 and they are now higher than before the collapse.
- The future price assumptions are based on historical trends. We recognise that in 2021 gas price assumptions underwent a period of significant instability; however, futures curves show gas prices within the range set out above and the assumptions represent an appropriate range based on historical trends. Although prices are above this range at the time of writing, future prices until 2050 are unknown.
- The period of low prices in 2020, the disruption caused by the COVID-19 pandemic and the reduced financial resources for the fossil fuels sector has led to capital rationing in the O&G industry. As a result, our analysis sets a capital rationing hurdle rate for the development of probable and possible fields and projects of ≥0.3.
- Capital rationing is widely acknowledged in the industry. Investment opportunities exist around the world for O&G companies and, with limited capital budgets, projects are ranked to help obtain the greatest return on investment.
- The hurdle rate is calculated by dividing the project's real post tax Net Present Value by the real pre-tax investment cost. This is a standard measure used in the industry and by academic institutions. The choice of ≥0.3 was based on information provided privately by a number of investors in the UKCS.
- The base case scenario includes a two year delay for probable and possible projects. The current operational environment, including disruption brought on by the COVID-19 pandemic, low 2020 hydrocarbon prices and reduced financial resources for fossil fuels, has led to delays in final investment decisions, regulatory approval and development of probable and possible projects.
- A project is sanctioned only if it is covered by a current Development and Production Consent (DPC) issued by the NSTA; this applies even if a positive Final Investment Decision (FID) has been taken by the licensees.

**Key assumption**

The production forecast is based on the assumption that there are no new licences for exploration.

# Methodology and assumptions (cont'd)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## Production forecast methodology and assumptions (cont'd)

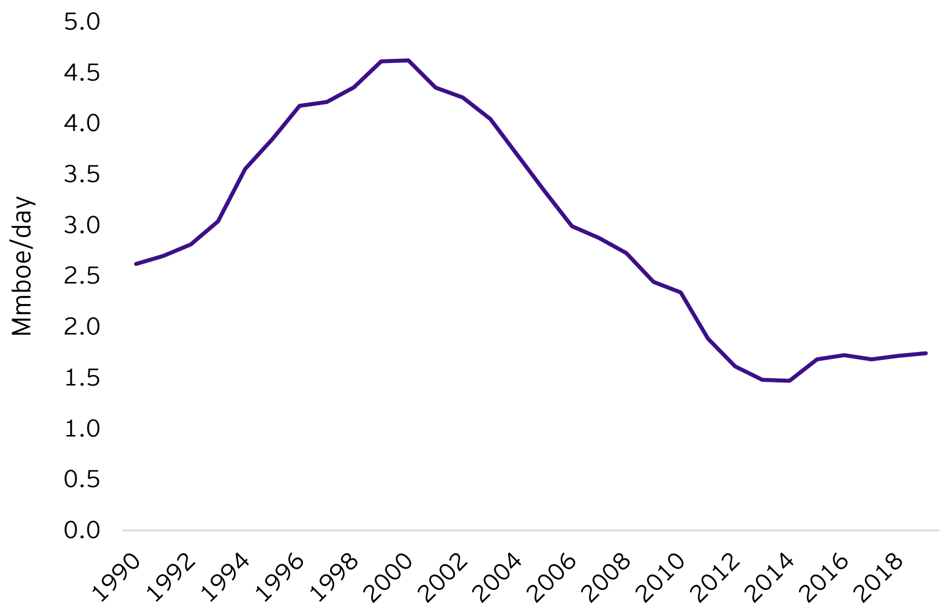
- Probable and possible refer to the probability of turning into a sanctioned project: possible projects are classified as having a 1-49% probability of being converted to a sanctioned field and probable projects have a 50-99% probability of being converted to a sanctioned field.
- The analysis differs from other hydrocarbon production forecasts as it is based on O&G operators' best estimates of future production. This detailed bottom-up model brings effective insight into O&G operators' expectations of future production on a field-by-field basis. This is more effective than a top-down approach that explores production on an aggregate basis. We are not aware of other publicly available forecasts that include details of sanctioned, probable and possible trajectories. While there are published reserve positions there are no projections of production over time.
- The tax analysis assumes net tax receipts as the sum of tax receipts from Ring Fence Corporation Tax (RFCT) and Supplementary Charge (SC) minus refunds. It assumes that participators have income to offset tax depreciation on investments for both RFCT and SC purposes. In practice participators in the fields included within the analysis may have tax attributes which will shelter the profits from the incremental investments, but the model does not have sufficient data on the historical tax status of individual entities to factor in these attributes where they exist. Additionally, Petroleum Revenue Tax (PRT) is excluded from the analysis. Whilst Finance Act 1993 abolished PRT for fields sanctioned after March 1993, the tax has continued for fields sanctioned prior to that date, and includes many of the largest fields in the UKCS, and associated infrastructure. The PRT rate was permanently reduced to 0% on 1 January 2016. Before that change the rate was 50%. Because expenditure on decommissioning can create a loss for PRT purposes for fields within the scope of PRT, such losses may be carried back through the years where the 0% rate has applied and result in repayments of PRT for periods in 2015 and earlier. The models have no means to cater for these complex scenarios.

## Historical UKCS O&G production

Before exploring our O&G production forecast for the ScotNS it is important to understand the historical UKCS production trends. This provides context to explore future trends and understand the current levels of O&G production.

O&G production peaked in the late 1990s and early 2000s following a period of rapid production expansion. Combined O&G production volumes reached their highest point in 1999 at 4.6 million boe/day. Following this peak, both oil and gas followed a very similar decline curve, reflecting diminishing exploration activity, reduced new discoveries and the more expensive operating environment. This activity was market led, with commercial decisions being taken by the O&G operators.

### Historical total O&G production from the UKCS




Source: EY analysis

# Scottish North Sea production forecast

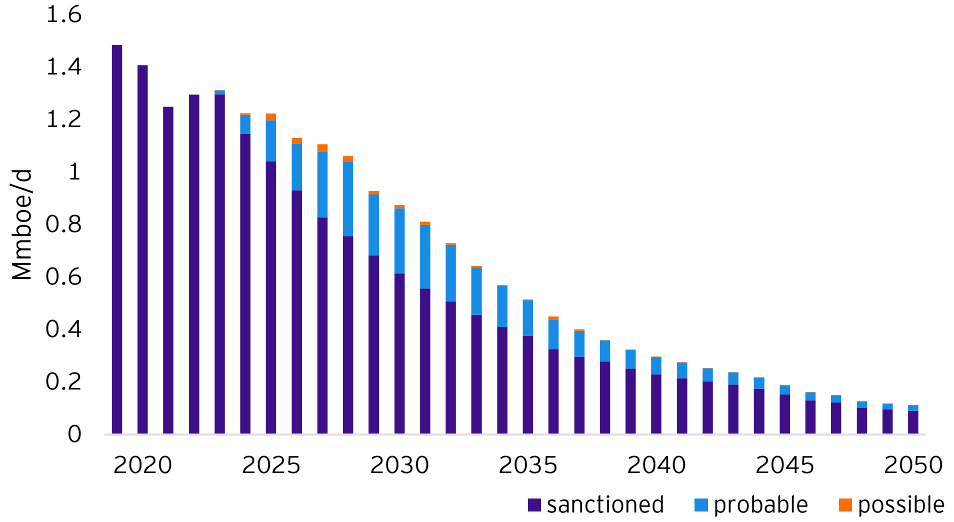


## Base case production forecast

The 2019 to 2050 ScotNS production forecast shows:

- Total cumulative hydrocarbon production between 2019 and 2050 is 7.6bn to 8.0bn boe. Sanctioned projects contribute 6.5bn to 6.6bn boe, probable projects 1.0bn to 1.3bn boe and possible projects 0.1bn boe. The cumulative total is 1.3bn boe below the NSTA's proven reserves and contingent resources of the UKCS as of 2019.
- The high and low price scenarios yield production levels do not deviate significantly from the medium scenario. This is driven by the NSTA Stewardship Survey data underpinning the analysis where operators will have taken a view of commodity prices and risk when contributing to the survey. As a result, there are no explicit assumptions regarding pricing assumptions in the data or alternative scenarios. As a result, future changes to the industry's central view on future prices may impact the decline trajectory.
- The figure opposite shows the annual hydrocarbon production from 2019 to 2050 (this includes the two year delay to possible and probable projects). The decline in 2021 of 160,000 boe/d (compared to 2019/2020) can be attributed to the Forties Pipeline System maintenance. It was estimated that 80 fields were affected and 10% of the UK's production was shut down.[2]
- From 2021 production will recover slightly but a decline will begin in 2026. By 2035 production will be less than half the current levels. New projects may only be able to slow the decline of existing production without a possibility to return to pre-pandemic levels.
- Delays to approving and developing probable and possible projects will result in a sharper decline.
- This trend is broadly consistent with the NSTA's production projections. As at September 2021, the NSTA forecasts UK O&G production rates of 1.37m boe/day in 2021 falling to 0.2m boe/day in 2050.[1] Page 25 of this report contains more information on the NSTA production and reserves projections.

### Hydrocarbons production in Scotland 2019 to 2050 medium case with delay scenario




Source: EY analysis

### Table 2: Cumulative production summary

| Cumulative hydrocarbon production in the ScotNS – 2 year delay scenario (bn boe) | | | | |
|---|---|---|---|---|
| Price Scenario | Sanctioned | Probable | Possible | Total |
| Low | 6.493 | 1.048 | 0.064 | 7.605 |
| Medium | 6.532 | 1.154 | 0.067 | 7.753 |
| High | 6.554 | 1.318 | 0.104 | 7.976 |

Source: EY analysis

[1] https://www.NSTAuthority.co.uk/data-centre/data-downloads-and-publications/production-projections/
[2] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/092320-forties-2021-shutdown-to-take-out-chunk-of-uk-oil-and-gas-production-for-month

# Scottish North Sea production forecast (cont'd)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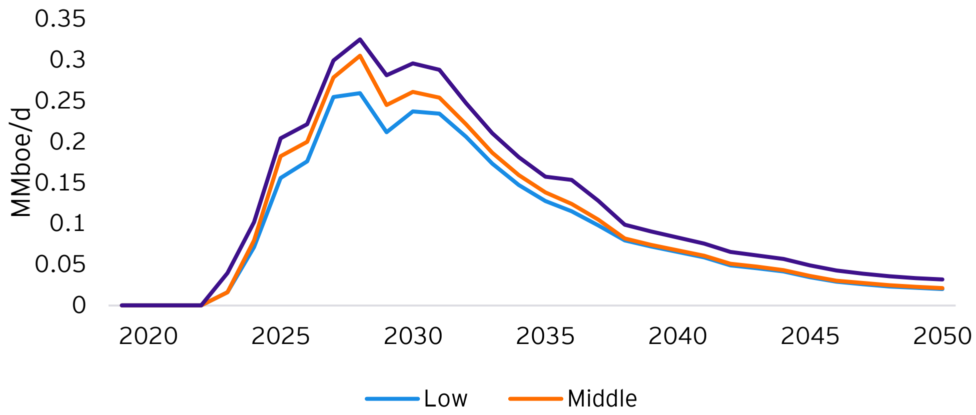
## Base case production forecast (cont'd)

- The different price assumptions have an impact on the production from probable and possible fields. Lower prices reduce the probability of projects passing the capital rationing hurdle and, as a result, less production occurs. Higher prices also allow for a longer profitable production period from a given field, pushing back the date at which production ceases.
- The figure opposite highlights the incremental production from the probable and possible fields in each price scenario. The difference is largest between 2025 and 2035, with an average difference of 22,000 boe per day. Production from probably and possible fields represents approximately 25% of the average total production over this same period (middle scenario). This analysis demonstrates that operators expect incremental production from probable and possible fields, in other words, the known projects, to take place between 2025 and 2035. However, the limitations of the data mean that this methodology may not capture the full spread of outcomes, particularly were prices to shift upwards. Decisions on capex in existing fields and new fields in particular could reduce the decline. Conversely more headwinds or perceived risk may reduce investment, and connected infrastructure may make fields uneconomic earlier.
- Our analysis also disaggregates the production outlook on a regional basis. Production from the Central North Sea (CNS) represents the largest proportion (55%) between 2019 and 2050, with the Northern North Sea (NNS) representing 20% and West of Shetland (WoS) representing 25%.
- The compound annual decline rate (CADR) for the CNS is 7.7% between 2019 and 2050. The NNS has a steeper decline rate, with production declining at a CADR of 12.6%, and the WoS has a CADR of 7.4%.
- The WoS is the only region where sanctioned production will grow to pre-pandemic levels after 2021, but production decline will begin in 2029.

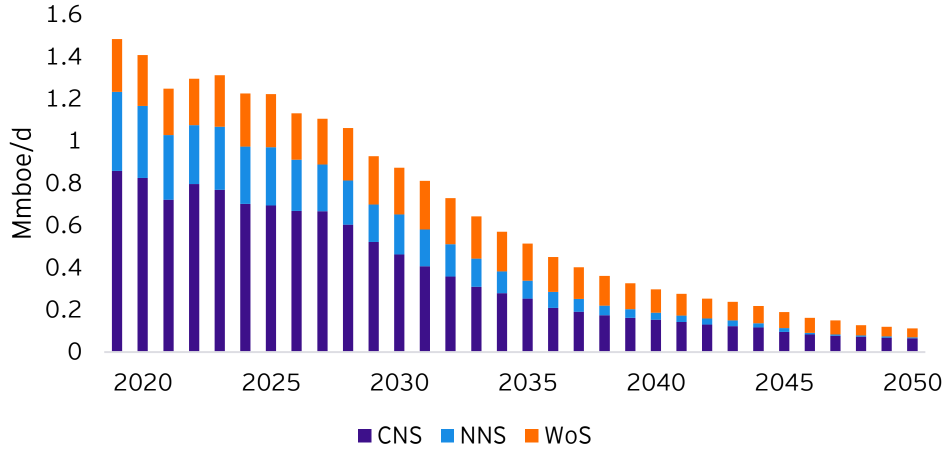
The analysis indicates that production from the ScotNS will decline with cumulative hydrocarbon production to be 7.7bn boe by 2050. This represents a decrease from 1.2m boe/day in 2021 to 0.9m boe/day in 2030 and 0.1m boe/day in 2050. It is likely that production will not return to pre-pandemic levels if delays to future investment and approval of future probable and possible projects occur. The maturity of the ScotNS and the UKCS is well publicised and the NSTA has undertaken its own assessment of future O&G reserves, which is explored overleaf.

### Incremental production from probable and possible fields




Source: EY analysis

### Total hydrocarbon production in Scotland 2019 to 2050 Medium case by region




Source: EY analysis

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## Additional O&G resources analysis

### Reserves and contingent reserves

The ScotNS O&G production forecast is unique analysis that is based on industry data and assumptions. There are no publicly available comparable studies. However, a common baseline for the industry is the reserves analysis undertaken by the NSTA.

The definitions used in our production forecast differ from those used to describe the NSTA reserves analysis. O&G reserves and resources in the UKCS are divided into three categories following the Petroleum Resource Management System of the Society of Petroleum Engineers: reserves (P), contingency resources (C) and prospective resources.

Additionally, given the uncertainty that surrounds these estimates, the O&G resources are further divided into ranges numbered 1, 2 and 3 depending on the level of confidence that they will eventually be produced. Using these categories, the NSTA has estimated the potential reserves for the UKCS. Table 3 highlights the NSTA estimation of reserves and contingent resources that remain in the UKCS (based on the last UK O&G Reserves Report of 2020). For simplicity we have shown the central estimate.

The EY production forecast accounts for reserves and contingent resources, in other words, the hydrocarbons more likely to be commercially and technically viable. As a result, the NSTA central case of 9.0bn boe can be compared to the EY production forecast of 7.7bn boe. The assumptions used in the NSTA and our analysis are not directly comparable, thereby resulting in different conclusions. However, another reason for the difference is the EY forecast only accounts for production in the ScotNS compared to the NSTA's UK forecast.

### Table 3: 2019 NSTA UKCS reserves forecast (bn boe)

| | Central estimate (2P+2C) |
|---|---|
| Reserves | 5.2 |
| Contingent reserves - Producing fields | 2.1 |
| Contingent reserves - Proposed new developments | 1.7 |
| **Total covered by EY production forecast** | **9.0** |
| Prospective resources - Future marginal discoveries | 3.5 |
| Prospective resources – prospect and leads | 4.1 |
| **Further NSTA prospective resources** | **7.6** |

Source: NSTA reserves and resources report

### Prospective resources

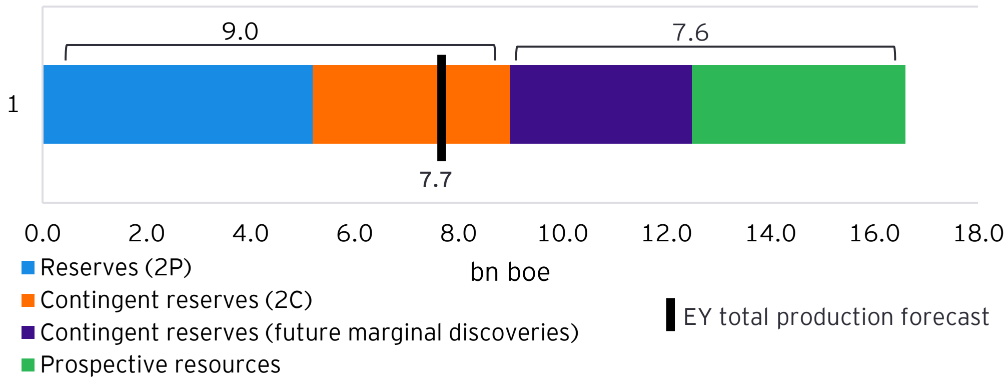
The NSTA analysis includes prospective resources. Prospective resources can be defined as O&G that has not yet been discovered but are considered likely to exist. As a result, there is less likelihood that the hydrocarbons are commercially and technically producible.

Prospective resources will require future licensing rounds and additional levels of exploration activity. With more scrutiny being placed on licensing and new field approval, the likelihood of these resources being commercially and technically viable is less certain.

The EY production forecast does not include prospective resources. The NSTA does, however, estimate prospective resources for the UKCS equate to 7.6bn boe (this includes the 2019 future marginal discoveries and the 2019 mean "prospects" figure). This is in addition to reserves and contingent resources. For these resources to be exploited, new licensing, exploration or development of undiscovered resources would need to take place.

Our forecast indicates that the ScotNS hydrocarbons production will remain at the lower range of NSTA estimated UKCS reserves, but substantial additional prospective resources may also exist.

### 2019 NSTA UKCS reserves forecast and comparison to EY production forecast




Source: NSTA reserves and resources report

# Scottish North Sea financial metrics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## UK O&G financial overview

The spotlight created by the energy transition is having an impact on O&G financing, as investors and lenders respond to public scrutiny of the sector. Funding for global O&G gas projects continues, not only to meet existing demand but also to support the O&G industry transition to low carbon alternatives and to funding emission reducing practices and technology.

Typically, investment is required to provide access and exploration activity, undertake extraction activity and to invest in transportation and processing facilities. This investment is expected to continue while ScotNS production continues. Historical investment peaked in 2014 following a surge in oil prices in the mid 2010s and a period of high oil price projections.

Our production forecast assumes that investment will be prioritised to the most promising resources and investment hurdles are utilised to ensure the funding is allocated to the most appropriate projects. Equity investment in the sector includes International Oil Companies and other corporate entities including major and independent O&G companies, National Oil Companies (NOCs), private- and state-owned investment funds and a range of other private investors.

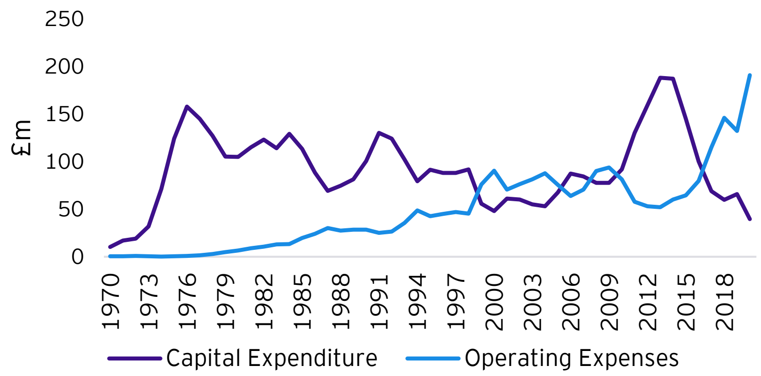
Due to the capital intensive nature of upstream O&G activity and unpredictable investment timings, it is unusual for a single sponsor to finance, develop and operate an upstream field. As a result, an unincorporated joint venture (UJV) is the more commonly used structure to access sources of upfront equity finance and spread the cost (and risk) amongst participants. A common source of financing employed in the upstream sector is reserve-based lending (RBL), which enables the raising of debt across a number of assets at various development stages and retention of a degree of operational flexibility.

The graph below highlights the average EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortisation) of several large O&G companies operating in the North Sea. This metric is used to analyse and compare profitability among companies, as it eliminates the effects of financing and capital expenditures.

Due to the high risk nature of the O&G projects and their capital intensive nature different sources of financing are required over the life of a project. We have also captured the weighted average cost of capital (WACC) for the O&G companies, showing the average cost of capital for these companies. This shows the minimum expected return the companies would expect to make. Given the fact that these O&G companies have similar operations (global and diversified), a large variation in WACC is not expected. However, the profitability of the industry is more volatile and varies with changes in commodity prices.

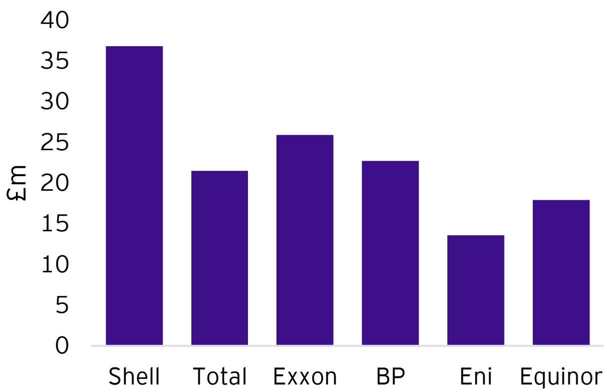
Our production forecast demonstrates that production is declining; however, this will still result in financial activity in the ScotNS. On the following pages the financial impact of this production and the associated net tax receipts that will be generated are explored.

### Historical UKCS investment (real)




Source: NSTA

### Average EBITDA (FY2017-19) for UKCS O&G companies




Source: EY

| Example O&G companies | WACC (Post Tax) |
|---|---|
| Shell PLC | 6.31% |
| Total SE | 6.44% |
| Exxon Mobil Corporation | 6.52% |
| BP PLC | 6.15% |
| Eni S.P.A | 6.56% |
| Equinor ASA | 6.84% |
| **Average WACC** | **6.47%** |

Source: NSTA

# ScotNS investment and expenditure

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## Expenditure in O&G activities

This section presents the outlook for expenditures in O&G activities in the ScotNS. The figure opposite shows the estimated sanctioned capital, operating and decommissioning expenditures in the ScotNS. Capital expenditure (capex) is the costs associated with the development of O&G projects or the undertaking of drilling activity. Operating expenditure (opex) is the routine costs associated with maintaining and operating after development has occurred. This also includes personnel and transportation costs.

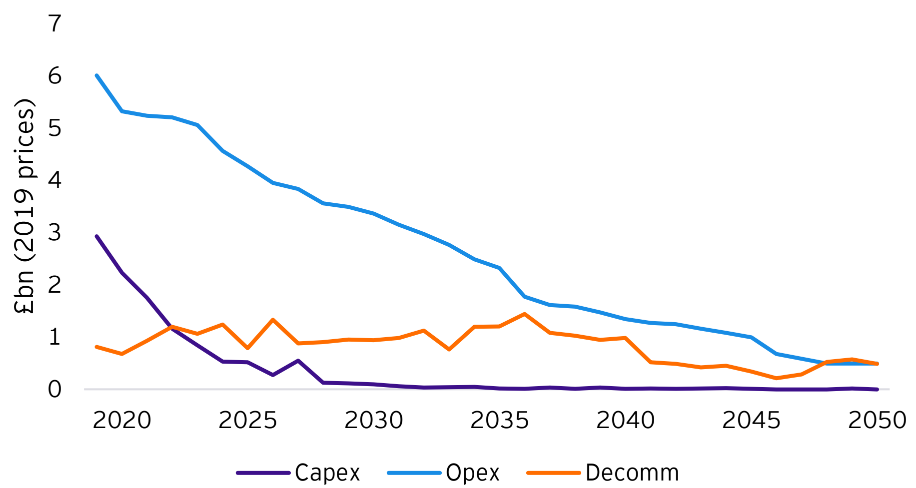
The different expenditure categories are helpful industry measures. Operating costs can be a proxy to understand future employment, while capital costs and decommissioning expenditure are relevant for the UKCS supply chain and the decommissioning sector to forecast demand for their services. A detailed examination of the ScotNS's economic footprint can be found in section 4.

### Capital costs

The analysis shows:

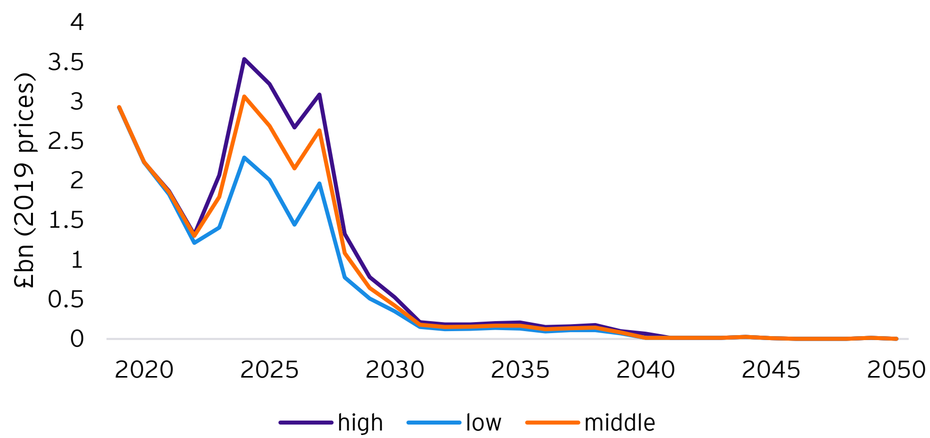
- When exploring the middle price scenario, we expect sanctioned capex to show a steep decline until 2029 and to have a small share of activity after 2030. If probable and possible projects are given regulatory approval and operators decide to go ahead, the expenditure outlook will increase. Capex will peak in 2024 at £3bn and spending may last until the early 2030s.
- Under the low price scenario, capex (including possible and probable fields) peaks at £2.9bn in 2019, fluctuating until 2027 before a rapid decline. Under the high price scenario, the peak will occur in 2024 at £3.5bn, before rapidly declining from 2027.
- The analysis demonstrates that under each scenario, we anticipate significant decreases in capital expenditure in the late 2020s and into the 2030s as a result of reduced activity in the declining basin.
- This analysis does not account for a significant change in regulatory approval for future fields. Were this to occur, the capital investment profile would change.

### Sanctioned expenditure from O&G activities in the ScotNS




Source: EY analysis

### Additional capex from probable and possible fields




Source: EY analysis

# ScotNS investment and expenditure (cont'd)



## Expenditure in O&G activities

### Operating costs

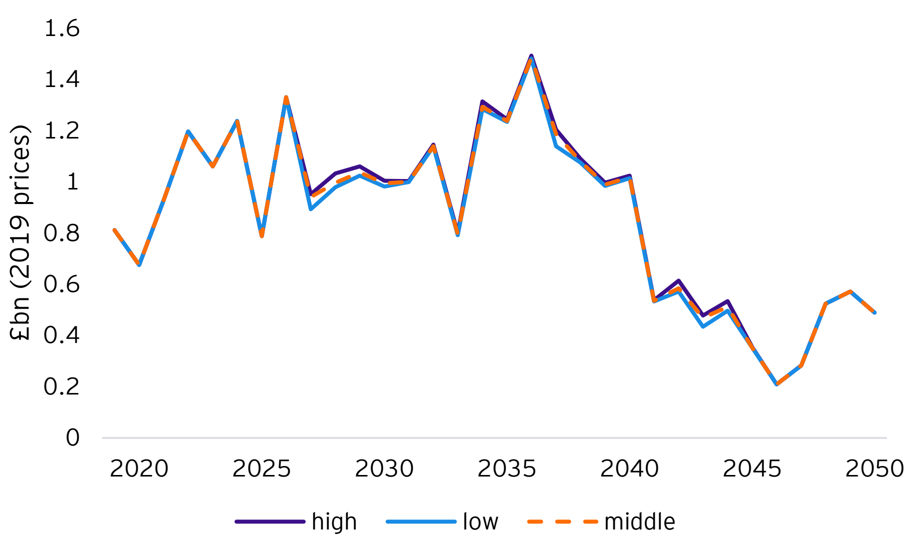
- Opex will be the main type of expenditure in the ScotNS during the outlook period, although we expect it to decline at an average annual rate of 7.5%. This reflects the expectation that overall production activity will decrease.
- The additional impact of probable and possible fields on operating costs is not as stark as for capex, but it is spread through the outlook period.

### Decommissioning costs

- Annual decommissioning expenditures will average £1bn until 2040 and then £0.5bn until 2050, resulting in decommissioning activity increasing its relative importance as the outlook unfolds.
- The impact of introducing probable and possible fields makes a marginal impact on the total decommissioning spend over time, with a less than 1% impact on the total decommissioning activity.

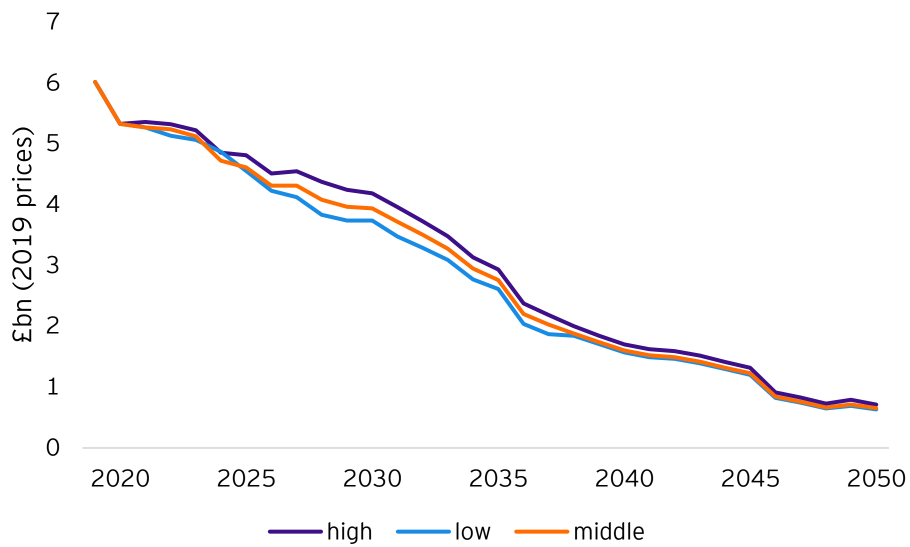
As a mature hydrocarbon basin, the ScotNS contains a lot of existing offshore O&G infrastructure. Owners of this infrastructure have obligations to decommission assets at the end of their economic lives, representing a significant liability for the O&G industry. However, the North Sea's O&G infrastructure also represents an opportunity in the transition to an integrated energy basin. In Section 6 of this report, we explore the assets in the ScotNS, the impact of decommissioning and the implications for the future integrated energy basin.

### Additional decommissioning expenditure from probable and possible fields




Source: EY analysis

### Additional opex from probable and possible fields




Source: EY analysis

# ScotNS net tax receipts



## Net tax receipts from the ScotNS

The next element to the outlook is the expected value of tax receipts. Although the projects in the ScotNS generate tax income, the corporate tax receipts accrue to HM Treasury.

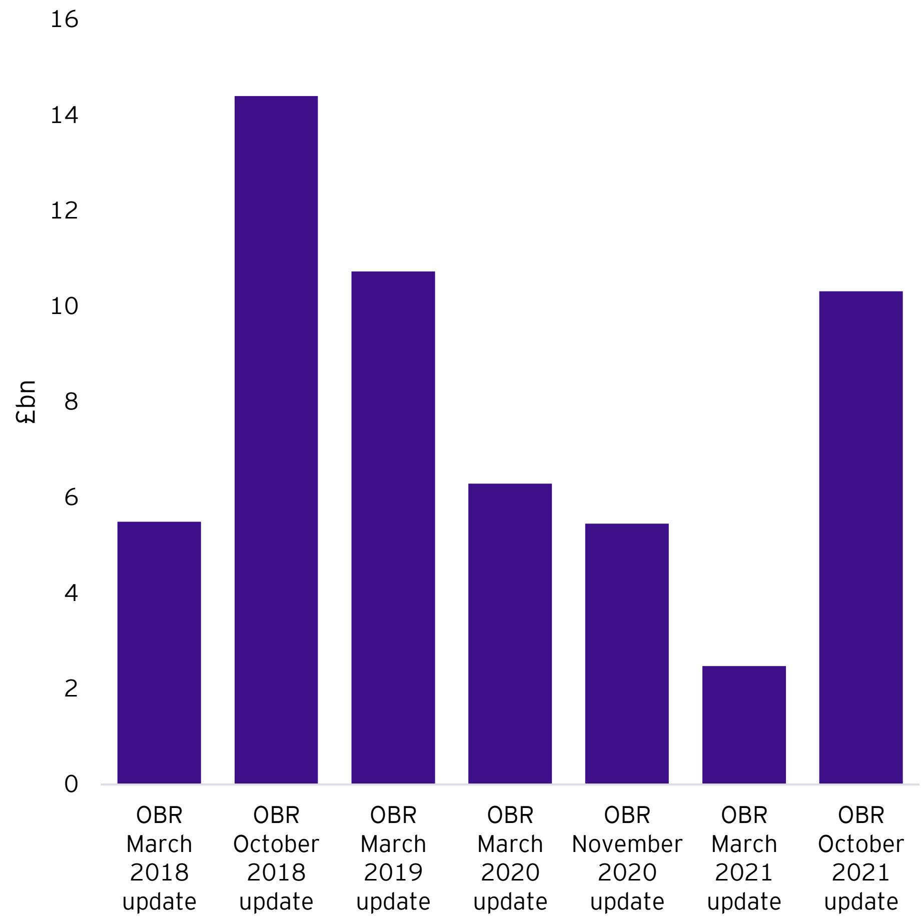
The object of this section is to provide an estimate of HM Treasury tax receipts from these ScotNS projects. As set out above, the economic model we have used to calculate these forecast receipts is premised on each participating entity being in a tax paying position. In fact many entities with interests in UKCS fields have brought forward trading losses partly driven by the oil price crashes in late 2019 and 2020. In some instances such losses will have been increased by the application of Ring Fence Expenditure Supplement, (RFES) which provides an annual uplift in the value of losses of 10% per annum for up to 10 years. The economic model has no way of determining the historical loss position of the various entities with interests in the fields and therefore cannot generate a more accurate figure of the projected fiscal receipts. In any case the corporate tax receipts from the UKCS participants is only one aspect of the tax take that is generated from these companies, with payroll taxes and national insurance contributions being significant components that are not factored into the model. (In contrast to the corporate tax receipts, the payroll taxes of Scottish taxpayers does fall to the account of the devolved government, albeit collected by HMRC.)

While these estimated corporate tax receipts are consistent with the 2021 Economic and Fiscal Outlook (EFO) of the Office for Budget Responsibility (OBR), actual values will vary depending on the volatility of future O&G prices and be impacted by the factors set out above.

For example, the OBR EFO from Oct 2021 shows a total of £11.2bn of corporate tax for O&G in the period 2021/22 to 2026/27 (an average of £1.9bn per year) and repayments of £1.3bn of PRT.

The graph opposite sets out the forecast North Sea tax revenues from successive OBRs on a rolling 6 year basis. The forecast is illuminating in that it highlights significant changes in forecast North Sea tax revenues on an annual basis. Whilst some of the changes in tax revenue are attributable to changes to the North Sea fiscal regime, and in particular the impact of RFES, the largest part of the variance is due to revisions in commodity price. Future changes in the long term commodity price will have a material impact on tax receipts, especially if that higher commodity price supported further exploration and the development of resources not contained within the current economic model.

### OBR O&G Corporation Tax and PRT cumulative forecast (rolling 6 year average)




Source: OBR

# ScotNS net tax receipts (cont'd)

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To explore future tax receipts from the ScotNS, we have undertaken tax receipt modelling based on the three production scenarios with the high, low and middle price scenarios.

Our analysis indicates:

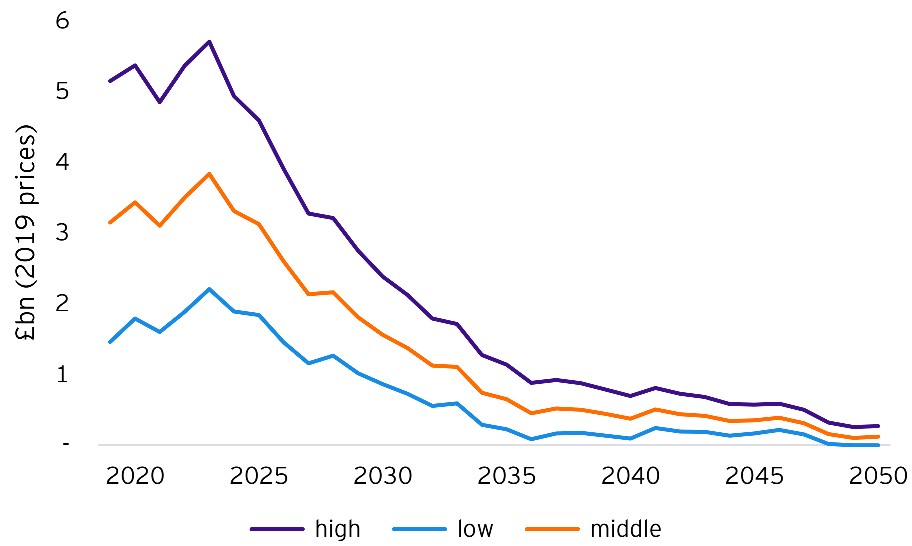
- Cumulative tax receipts for the period are £22.7bn in the low case, £44.1bn in the middle case and £68.9bn in the high case.
- Tax income from sanctioned projects will peak in 2023 and then decline, before a period of relatively stable receipts follows from 2036. Decreasing revenues from O&G activities and increasing decommissioning expenses (which obtain tax relief) help to explain this trend.

Our analysis and the OBR forecast summary highlights the impact of changes in the commodity prices and the wide range of potential tax receipt outcomes. Future tax receipts will also be impacted by historical tax losses as well as the future tax costs of decommissioning.

It is worth noting that PRT is excluded from the analysis. The effect of this is to exaggerate net tax receipts as decommissioning relief will be available against PRT paid prior to 2016.

Further exploration of global fiscal regimes can be found in Section 12.

### Illustrative tax receipts from sanctioned projects




Source: EY analysis

# Scottish North Sea production forecast



### Production forecast conclusion

The analysis indicates that production from the ScotNS will decline with cumulative hydrocarbon production falling by 7.7bn boe by 2050. This production forecast lies in the range of potential contingent resource estimates by the NSTA for the whole of the UKCS (utilising the NSTA's 1P, 2P and 3P scenarios, this provides a range of 6.3bn to 11.7bn boe). Additional prospective resources may also exist.

There are a number of factors that may result in the alternative production forecasts. Firstly, were commodity prices to change (i.e. commodity prices that are consistently higher or lower than currently modelled, or changes in the inputs to the NSTA Stewardship Survey), the production trajectory would change, while the reserves position would stay the same. For example, higher prices would result in existing fields performing differently, with additional operator investment and infill drilling. Lower prices would have the opposite impact. Additionally, other factors may also impact the trajectory. For example, production rates are impacted by a range of factors, including the age of the well. Production declines more quickly on newer fields than older fields, thereby potentially altering the production trajectory. Even a high oil price would not mean that contingent and prospective resources would necessarily be exploited. Much of these are in small fields that may never be economic to exploit, and the lack of existing infrastructure in those areas would make the incremental cost of extraction extremely high.

However, with rapidly changing O&G prices, primarily driven by the war in Ukraine, there are factors that may cause the industry to respond and the ScotNS production to increase. This could be reinforced by longer term high O&G prices and political signalling from the UK Government regarding balancing domestic energy security with net zero ambitions.

Some of these factors may also represent levers that the industry may use to increase or decrease production now. Analysis by Wood Mackenzie[1] highlights several opportunities that the sector could pursue to increase production in the short / medium term:

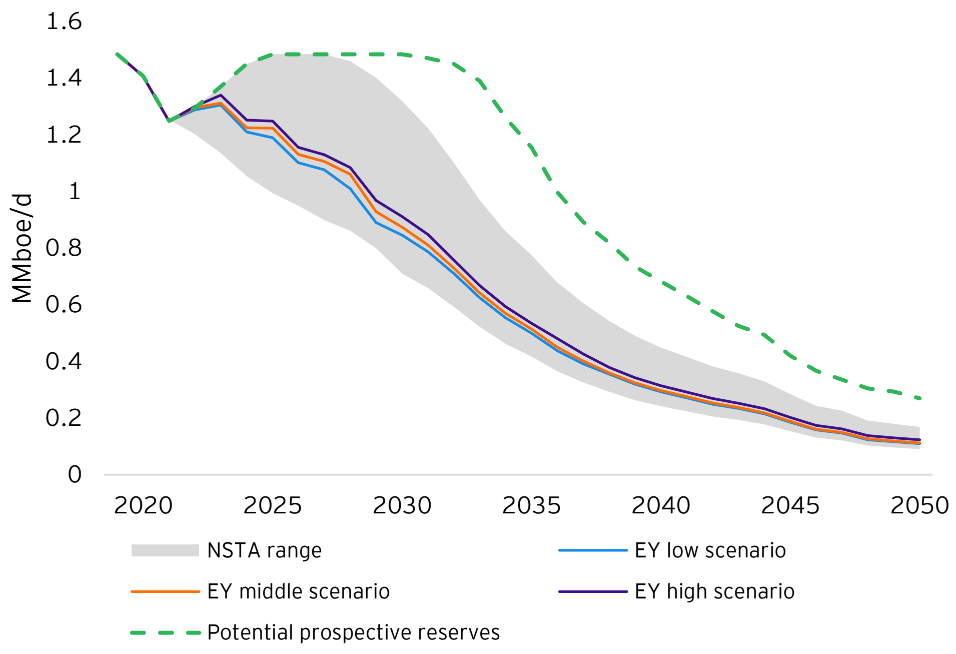
- Avoiding delays to the delivery of new projects. Our base case scenario includes a two year lead-time for probable and possible projects. Future delays to the sanctioning of probable and possible projects would alter this position further and Wood Mackenzie highlights that the O&G industry focus should avoid further delays.
- Operational changes to increase production, including maximising production uptime, accelerating infill drilling, delaying major field maintenance and extending infrastructure lifecycles.

Our report does not include detailed analysis to quantify the potential impact that these factors may create, but this would not have the same longer-term impact of increased exploration to exploit potential reserves.

### ScotNS production forecast conclusion

Our analysis indicates that the production forecast is consistent with the analysis undertaken by NSTA. Over 80% of the cumulative production forecast is represented by sanctioned projects (middle and high case), meaning the production has a high degree of certainty. Further prospective resources may exist; however, there is uncertainty around other reserves, which may only be extractable given the right economic, political and operating conditions.

### Total hydrocarbons production (sanctioned, probable and possible) and alternative reserves illustration[2]




Source: EY analysis, NSTA

[1] Wood Mackenzie "How much more oil and gas can the UK North Sea produce?" April 2022
[2] The chart includes estimates that illustrate how cumulative NSTA reserves could apply as a production trajectory. These have been developed to provide comparable production pathways that align with the EY scenarios.

# 4 Scottish O&G economic footprint

# ScotNS existing economic footprint



## ScotNS economic footprint

Our economic analysis provides an overview of the economic contribution and the scale of employment of the Scottish offshore O&G sector, including how the economic footprint of the sector is expected to evolve over time, as well as possible transitional considerations and analysis of the role the O&G sector in the wider economy.

To do this, we:

- Estimated the existing (2019) gross value added (GVA) and employment of the sector, including the direct, indirect and induced impacts.
- Estimated how the economic footprint of the sector will evolve to 2050, under different oil price and production scenarios. This is based on 2019 baseline GVA and employment and estimates for production and expenditure over time.
- Considered the GVA per job and mean income across the Scottish economy.
- Analysed the position of the O&G extraction sector in the rest of the economy, including the O&G sector supply chain (i.e. key sectors that contribute to O&G extraction) and sectors that currently depend on O&G extraction output.

The contents of this section and scope for this phase does not include considering the contribution of the sector to Scottish or UK exports or the net trade position over time. The current analysis only includes the economic impact of the upstream O&G extraction and support services and does not consider the full economic impact of other downstream activities that rely on O&G, such as petroleum manufacturing sectors.

# ScotNS existing economic footprint (cont'd)

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## Existing 2019 economic footprint

The purpose of this section is to quantify the economic impact of Scotland's (offshore upstream) O&G industry. This has been defined as the following sectors[1]:

- **Extraction of crude petroleum and natural gas** – referred to as 'O&G extraction' (Standard industrial classification of economic activity code SIC 06)
- **Support activities for petroleum and natural gas extraction** – referred to as 'O&G extraction support' (SIC 091, a component of SIC09 – Mining support service activities)

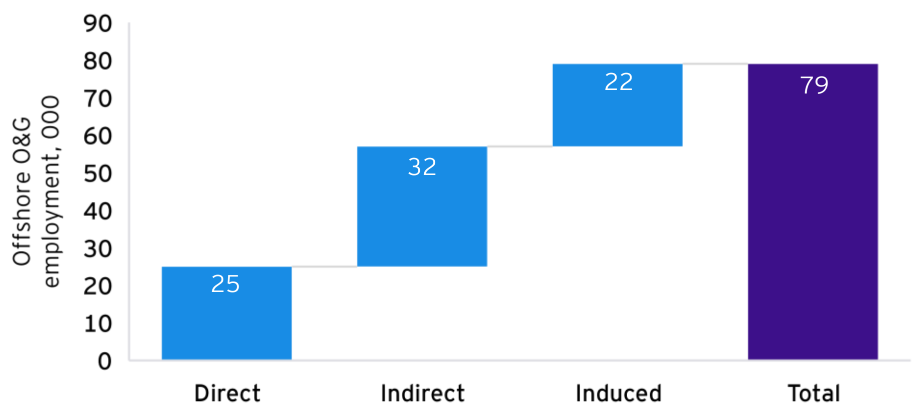
The analysis considers the contribution made by the O&G sector in Scotland towards GVA and employment. The economic contribution is comprised of three categories:

- **Direct:** impacts resulting from O&G sector activities and spending.
- **Indirect:** economic activity that occurs in the O&G industry's supply chain.
- **Induced impacts:** additional activity elsewhere in the economy, supported by spending of O&G sector employees and those employed in the O&G industry's supply chain.

### Employment and GVA total impact

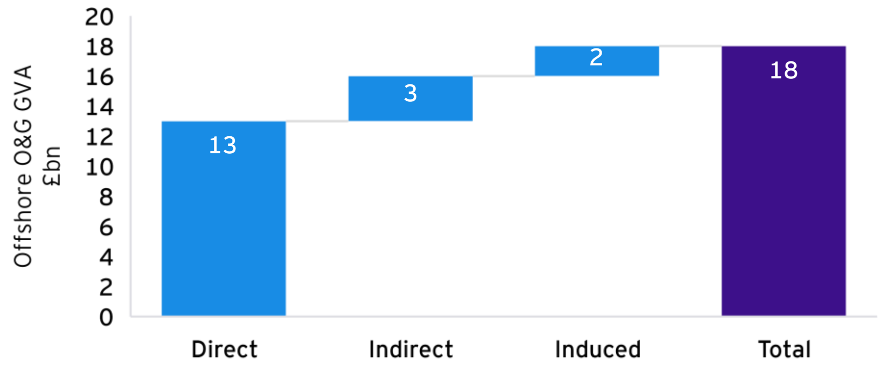
- It is estimated that 79,000 jobs were supported by Scotland's O&G sector in 2019, comprising 25,000 direct, 32,000 indirect and 22,000 induced jobs. This contribution is equivalent to 3% of all of Scotland's total employment. Of the 25,000 direct jobs, 98% were located within Aberdeen City and Aberdeenshire. Scotland's direct employment accounts for 82% of the total direct employment in the UK O&G industry, hence Scotland's O&G sector supports a significant proportion of the total O&G supply chain.
- In 2019, the O&G sector is estimated to have contributed a GVA of £17.9bn to Scotland's economy, amounting to £13.3bn direct, £2.5bn indirect and £2.0bn induced GVA. This contribution is equivalent to 10% of Scotland's total GDP (including a geographical share of UK Extra-Regio activity).
- The direct GVA accounts for 75% of the total GVA contribution of the sector in Scotland, a relatively high proportion that reflects the nature of the O&G sector, in particular, the degree of commercial risk and price volatility (e.g. oil prices), and its capital intensity. A high proportion of the direct GVA accrues to capital investors (rather than employees), reflecting the price volatility with O&G exportation, and hence the high GVA contribution is either reinvested or paid to shareholders. This is reflected in the fact that the GVA per job of the O&G extraction sector is £1.1m, 15 times higher than the average for the Scottish economy as a whole. A significant proportion is also paid to the UK government through taxation.

### Employment contribution (2019)




Source: EY analysis, BRES

### GVA contribution (2019)




Source: EY analysis, ONS

1. This analysis covers the economic footprint of the listed sectors. The full economic impact from other related downstream sectors, and sectors that require extracted O&G as a direct input is not included in this analysis.

# ScotNS existing economic footprint methodology



## Economic impact methodology

In order to assess the direct, indirect and induced impacts, a set of economic multipliers drawn from "Input-Output" tables are applied to the direct GVA and employment of companies in the O&G sector to derive the additional indirect and induced impacts.

A multiplier is an estimate of the extent to which each unit of output of the sector requires the production of a number of supporting units of goods and services in other sectors of the UK/Scottish economy as inputs into the O&G sector's production. The production of each unit of input also requires the application of labour – i.e., it supports employment.

The Office for National Statistics (ONS) publishes a statistical report called the 'Input-Output tables', which outlines the relationships between different industries and how the outputs from one industry are used as inputs into another. Input-Output tables provide a consistent representation of national economic accounts, illustrating interdependencies between industries.

The methodology used in this study is based on this approach. It quantitatively estimates how a unit of GVA and employment in the O&G sector leads to additional GVA and employment across the O&G sector's supply chain and the wider economy.

## Direct impacts

The direct impacts or contribution of the Scottish O&G sector have been calculated using official data on sector and regional GVA and employment:

- Employment: obtained 2019 BRES[1] data for Scottish jobs in SIC 06 and 091

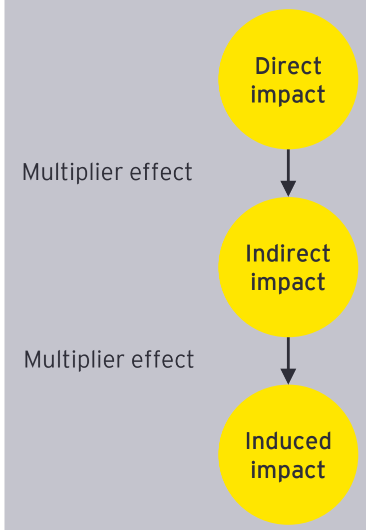
### Table 4: Direct employment data (2019)

| | Direct employment (employees) |
|---|---|
| 06 O&G extraction | 10,040 |
| 091 O&G extraction support | 15,000 |
| **Total** | **25,040** |

- GVA: obtained 2019 annual business survey[2] data for SIC 06. For SIC 091, a GVA estimate has been calculated based on taking 99.8% of the total GVA of SIC 09 (mining support services), as employment within SIC 091 makes up 99.8% of total Scottish employment in SIC 09 (based on BRES data), and it is assumed this same proportion is reflected in GVA of the sub-industry (as more detailed data for GVA by a lower level SIC code is not available compared to that provided for employment data).

### Table 5: Direct GVA data (2019)

| | Direct GVA (£m) |
|---|---|
| **06 O&G extraction** | 11,500 |
| **091 O&G extraction support** (estimate, taking 99.8% of SIC 09 GVA) | 1,836 |
| **Total** | **13,336** |




Direct impact: Employment and GVA generated directly as a result of activities of companies within the O&G extraction and O&G extraction support services sectors (SIC 06 and SIC 091); i.e., direct employees of these companies and activities generating revenue

Indirect impact: Additional impacts on the wider economy that occurs as a result of industries in the supply chain of the O&G sector

Induced impact: Impacts generated by increased employee income, through both direct employment in the O&G sector and indirect employment in the supply chain

Total impacts are captured through the use of multipliers, which measure linkages between industries of the economy.

The indicators for measuring impacts are expressed in terms of the direct, indirect and induced GVA and employment.

1. 2019 Business Register and Employment Survey : open access, ONS Crown Copyright Reserved [from Nomis]
2. Annual Business Survey, COUNTRY AND REGION BY SECTION AND DIVISION, 2008-2019
https://www.ons.gov.uk/businessindustryandtrade/business/businessservices/datasets/uknonfinancialbusinesseconomyannualbusinesssurveyregionalresultssectionsas

# ScotNS existing economic footprint methodology (cont'd)



## Indirect and induced impacts

Scotland's indirect and induced impact has been calculated via the following steps:

1. **Calculating UK O&G sector multipliers:** The UK GVA and employment multipliers of SIC 06 and SIC 09 have been calculated, using EY's economic impact model. These multipliers are adjusted to remove overlapping effects between each sector[1].
   - The multipliers are driven by the underlying structure of the UK economy. For instance, they reflect current intermediate consumption by firms (their supply chain spending) and final consumption expenditure (demand) by households. This data is collected and updated regularly by the ONS to be reflected in new releases of the Input-Output and Supply and Use tables.
   - The multipliers are assumed to remain stable in our forecast. While it can be expected that the structure of the UK economy will change over time, this would be a gradual process, and precise changes are difficult to predict. Hence it is reasonable to use the latest multipliers for future projections.
2. **Calculating UK wide O&G sector impact:** The multipliers are applied to UK direct employment and GVA figures (these direct figures are described on the previous page) to calculate the total UK-wide impact (including indirect and induced). At a UK level, the O&G industry is expected to contribute £35.4bn in GVA and support nearly 220,000 jobs.
3. **Estimating the Scottish share of UK indirect/induced impacts:** This has two components:
   a. The spend by the Scottish O&G sector in its supply chain by sector has been estimated using Scottish Satellite Accounts[2] and adjusted to 2019 spend, by assuming the same relative change as observed in direct GVA between 2016 and 2019. Page 42 contains further detail on the industries within Scotland's O&G extraction supply chain.
   b. The proportion of the spend that occurs in Scotland itself is then estimated. This is derived by calculating the Scottish proportion of UK GVA and employment for each sector in Scotland's O&G extraction sector supply chain, and then deriving an overall weighted average share across all sectors. This implies that Scotland accounts for 28% of overall UK's O&G supply chain jobs, and 27% of GVA.
4. **Applying the Scottish supply chain share estimate to calculate indirect and induced impacts:** It is assumed that the Scottish O&G supply chain is distributed across the UK based on Scotland's share of UK employment and GVA of each industry. The 28% and 27% supply chain estimates have been applied to total UK wide estimates of indirect and induced employment and GVA to estimate Scotland's indirect and induced impacts. These indirect and induced impacts form part of the total impact outlined in the table below.

### Table 6: UK Employment and GVA total impacts (2019)

| UK employment | Direct | Indirect | Induced | Total |
|---|---|---|---|---|
| 06 O&G extraction | 13,300 | 78,269 | 54,740 | **146,308** |
| 091 O&G extraction support | 17,100 | 33,807 | 22,502 | **73,409** |
| **Total** | **30,400** | **112,076** | **77,241** | **219,717** |

| UK GVA (£m) | Direct | Indirect | Induced | Total |
|---|---|---|---|---|
| 06 O&G extraction | 16,431 | 4,985 | 3,955 | **25,371** |
| 091 O&G extraction support | 2,384 | 4,320 | 3,369 | **10,073** |
| **Total** | **18,815** | **9,305** | **7,324** | **35,444** |

### Table 7: Scottish Employment and GVA total impacts (2019)

| Scottish Impact | Employment | GVA (£m) |
|---|---|---|
| Direct | 25,040 | 13,336 |
| Indirect | 31,940 | 2,547 |
| Induced | 22,012 | 2,005 |
| **Total** | **78,992** | **17,888** |

1. This is to ensure the "direct" employment and GVA of the support services sector is not reflected in the indirect impact of the O&G extraction sector. As spending on support services is part of the supply chain of the O&G extraction sector.
2. An approximation for supply chain spend has been used as intermediate consumption data for SIC 06 in official Scottish I-O tables does not include the offshore economy, source: https://www.gov.scot/publications/scottish-national-accounts-programme-whole-of-scotland-economic-accounts-project/

# ScotNS economic footprint methodology and scenarios



## Limitations to the approach for assessing current impact

- The main limitation is that this approach assumes that spend in the supply chain by the Scottish O&G industry occurs across the UK (not just Scotland), with the proportion of spend assumed to take place in Scotland reflecting the Scottish employment and GVA share of each particular industry. This may not capture the full contribution of the industry to Scotland, because firms in the O&G extraction supply chain may be disproportionally clustered around areas of production. Thus a greater proportion of the O&G supply chain could be located in Scotland than we have estimated, given Scotland's much higher share of direct O&G activity than that of the rUK.
- A number of adjustments have been made to GVA and employment multipliers to avoid double counting the impacts of spending between sectors. However, there is still some potential risk of over-estimating O&G extraction support (SIC 091) indirect and induced impacts, as O&G extraction support is a major component of the O&G extraction (SIC 06) supply chain.
- Estimates of indirect and induced employment are sensitive to alternative estimation approaches for multipliers and assumptions over the share of O&G supply chain spend within Scotland, hence there will be variation with other published figures of the sector's GVA and employment by OEUK.

## The approach to estimating the economic footprint over time

- Employment has been forecast up to 2050, using the 2019 estimate as a baseline, and then assuming that total employment changes in line with projected operating expenses. Opex is the most direct measure available for workforce costs (although it will also include other non-staff expenses related to the operation of the O&G extraction infrastructure, such as fuel, maintenance, insurance costs). It is assumed that labour productivity is constant, due to there being limited scope for improvement in productivity as a result of declining investment in the sector and declines in production (limiting economies of scale).

GVA has been forecast using the 2019 estimate as the baseline and indexing this with forecasts for revenue less opex of the sector *[(production x price ) less opex]*, as GVA is defined as revenue less intermediate expenditure (cost of sales and operating expenditure).

### Table 8: Economic forecast scenarios

| Scenario | Oil price[1] | Project category |
|---|---|---|
| Low case | Low | Sanctioned |
| Central case | Medium | Sanctioned |
| High case | High | Sanctioned, Probable and Possible |

We have estimated GVA and employment forecasts up to 2050, under three scenarios with varying oil price and projects. The production levels under each scenario is aligned with forecast data in section 3[2] . The results of these scenarios is described on the next page.

## Limitations to the forecasting approach

- It has been assumed that the proportion of the O&G supply chain spend that occurs in Scotland is constant. This will be dependent on changes in the locations of each supply chain industry across the UK, as well as government policy to encourage O&G supply chain spending to remain within Scotland.
- As discussed on the previous page, the multipliers used to calculate the 2019 impact have been assumed to remain constant for forecasts of the economic footprint over time, given the challenges in forecasting long term structural changes. However, a sensitivity has been included to the forecasts to capture the impact of a +/- 10% change in the multipliers.

1. In line with oil prices outlined in section 3
2. Refer to pages 21 and 22 which outlines further detail on the modelling approach and limitations

# ScotNS economic footprint over time

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## Employment forecast over time

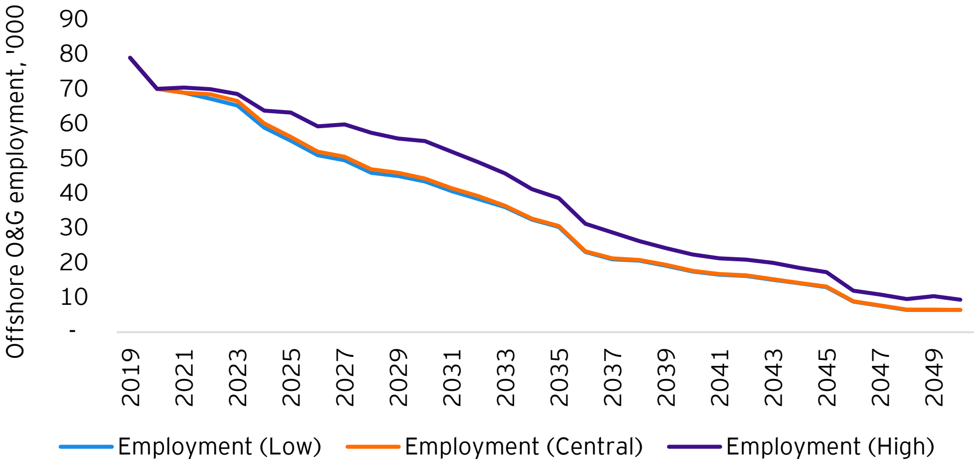
- Employment in the sector is expected to decline from 2019 onwards in all scenarios. The pace of decline is slower in the 'High' case from 2023 onwards. This is because this scenario includes additional projects (possible and probable over and above currently sanctioned activity), which in turn leads to higher operating costs and hence higher employment.
- Under the central scenario, by 2030 total employment is expected to decline to 56% of 2019 levels, from 79,000 jobs to just over 44,000 jobs.
- The employment forecasts are not impacted by oil price under each scenario as they are driven by operating expenses which varies with approved projects and production levels. These production levels do not vary under the specific 'Low', 'Central' and 'High' price scenarios[1]. Therefore employment forecasts are the same under both the 'Low' and 'Central' scenarios, which assume only sanctioned projects take place but with different oil price scenarios.

## GVA forecast over time

- Scotland's GVA for the O&G sector is estimated to have recovered to 90% of 2019 levels in 2021, but the overall size of the sector is on a downward trend in line with production forecasts.
- Under the 'High' case scenario, oil prices are higher and this scenario assumes that the possible and probable projects are approved. GVA is expected to increase to 18% above 2019 levels in 2023, then reduce gradually to 6% of 2019 levels in 2050 ('High' case).
- Under the 'Central' scenario, by 2030, total GVA is expected to decline overall to £7.0bn, 39% of 2019 level of £17.9bn.
- The difference in outcome under scenarios is largely driven by the oil price.

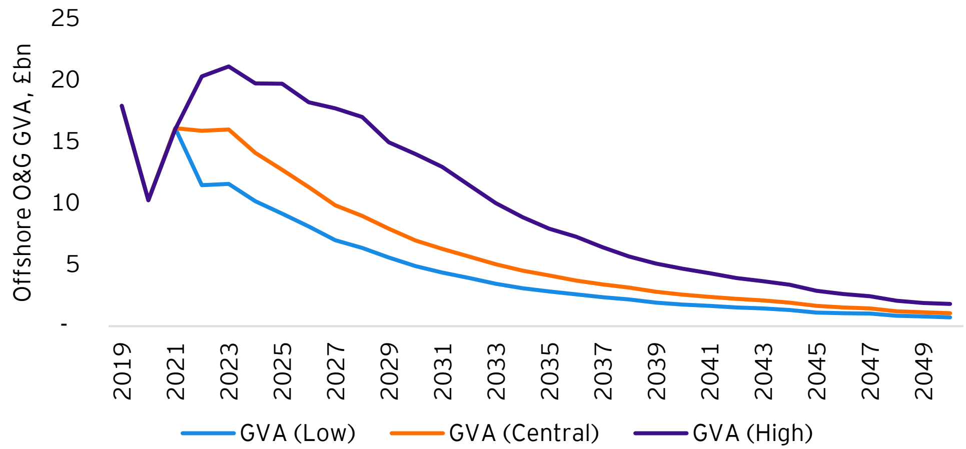
1. This is based on modelling from EY's independently commissioned analysis which reviewed whether possible and probable projects passed a capital rationing hurdle under the price scenarios. If the projects met the hurdle and went ahead, the same expenditures estimated by the operator in the survey were used, and it was reviewed whether any difference was necessary in cessation of production date. Changes in prices affect which projects are developed, rather than expenditures of the projects. The modelling forecast that in the 'Central' or 'High' price cases the same amount of projects are expected to ahead in all price scenarios.

### Total employment (direct, indirect, induced) forecast




Source: EY analysis

### Total GVA (direct, indirect, induced) forecast




Source: EY analysis

# ScotNS economic footprint over time – sensitivity testing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## Sensitivity of forecast to changes in multiplier

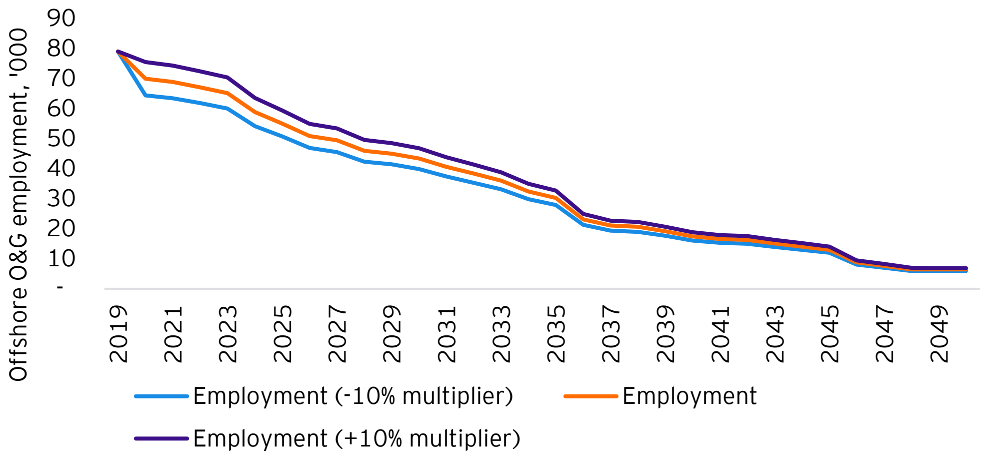
- As a sensitivity, the assumed employment and GVA multipliers have been adjusted by +/- 10% in forecast years[1] (beyond 2019) to review the impact on forecast employment and GVA under the central scenario.
- A 10% decrease in the employment multiplier leads to a 8% decrease in forecast employment each year (compared to the estimate using the baseline multiplier). Under a 10% increase in employment multiplier, there is a 8% increase in the forecast employment each year.
- A 10% decrease in GVA multiplier generates a 5% decrease in forecast GVA each year (compared to the estimate using the baseline multiplier). Under a 10% increase in GVA multiplier, there is a 5% increase in the forecast employment each year.

## Sensitivity of forecast to changes in supply chain location assumptions

- The indirect and induced impacts of this supply chain on Scotland's total GVA and employment is dependent on how much of the supply chain is located within Scotland, or elsewhere in the UK. A change in assumptions for the supply chain location would impact the base line (2019) estimate. Forecasts would follow the same path as outlined in the previous page, but start at a higher or lower baseline level with changes in the supply chain assumption.
- As a sensitivity the supply chain location assumption has been adjusted by +/- 10p.p. in the baseline year (2019) (e.g. 27% assumption would vary to 17% or 37% under +/- 10p.p). This results in a +/- 24% change in the estimated employment in the baseline (ranging from 60k to 98k jobs in 2019 under this sensitivity).
- The +/- 10p.p. sensitivity results in +/- 9% change in estimated GVA in the baseline (ranging from £16.2bn to £19.5bn GVA in 2019). GVA is relatively less sensitive to changes in the supply chain location than employment, this is because a higher proportion of total jobs are indirect and induced (68%), compared to indirect and induced GVA (25%).
- There is potential to generate up to an additional 136,841 jobs through indirect and induced employment if all of the spend by the Scottish O&G extraction industry was with companies based in Scotland. This would also lead to an additional GVA impact of up to £11.7bn in 2019.

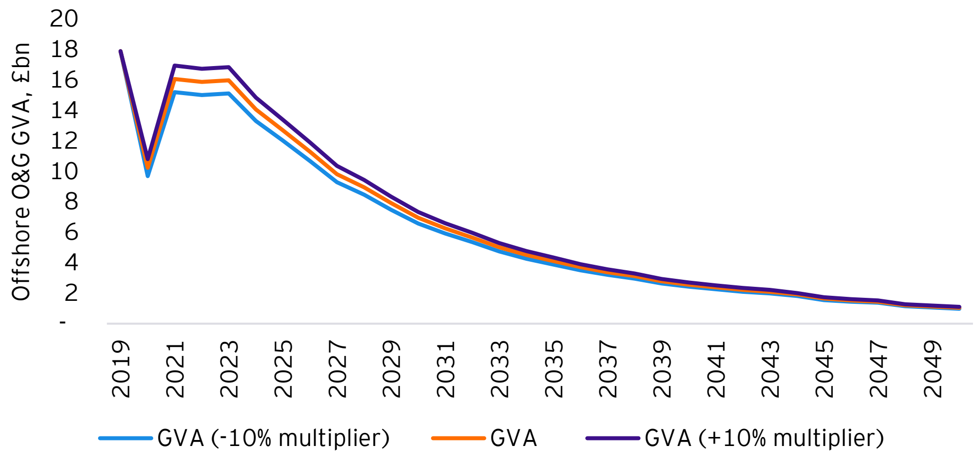
1. The adjusted multiplier is assumed to be constant across the entire forecast period between 2020 and 2050.

## Changes in multiplier in Central scenario employment forecast




Source: EY analysis

## Changes in multiplier in Central scenario GVA forecast




Source: EY analysis

# GVA per job and mean income across sectors

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This page considers the GVA per job and mean incomes generated by the Scottish O&G extraction and extraction support sectors relative to other parts of the Scottish economy, to understand how the sector's GVA contribution is benefiting direct workers in the O&G sector (rather than this value being transferred outside Scotland), and to understand the relative value of the sector for its employees compared to the rest of the economy.

It is noted that the contribution of the O&G sector to the Scottish economy is dynamic and changing over time. For instance, between 2000 and 2019, O&G production levels in Scotland reduced by 56% in value whilst Scottish GDP levels more than doubled, principally as a result of declining O&G reserves. The volume and value of O&G production is also highly sensitive to commodity prices which are extremely volatile; for instance, crude oil prices increased by almost 400% between 2010 and 2013 in real terms, before halving by 2015.

## GVA per job and mean income comparisons

The table on the right outlines the estimated direct GVA per job in the Scottish offshore O&G industry (SIC 06 & 091), the energy sector and the economy as a whole. GVA per direct job for O&G extraction (SIC 06) is £1.1m GVA per job – over 15 times higher than for the Scottish economy as a whole. The relatively high value of O&G extraction GVA per job reflects the relatively high returns expected in the O&G sector, given the degree of commercial risk and price volatility. A large proportion of the GVA may therefore be paid out as dividends to shareholders, as well as paid to government through taxation. Further consideration would be needed to estimate the proportion of value retained within Scotland.

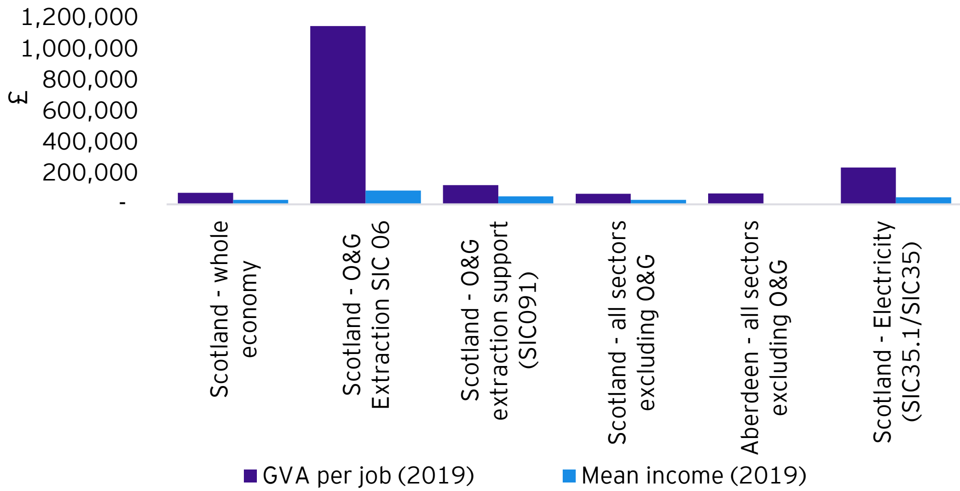
Employees in the O&G extraction sector earn a mean income of £87.8k, while mean incomes in O&G extraction support are £50.5k. Again, both of these figures are well above the Scottish average of £28.7k.

The GVA per job of the Scottish economy in all sectors excluding O&G is £67.6k, which is 6% below the whole economy average. Therefore there is a risk that the transition away from O&G could leave the Scottish economy smaller, and with lower average incomes.

### Table 9: GVA per job and mean income[1] comparison

| £ | Scotland - whole economy | Scotland - O&G extraction (SIC 06) | Scotland - O&G extraction support (SIC 091) | Scotland - all sectors excluding O&G | Aberdeen - all sectors, excluding O&G | Scotland - Electricity (SIC 35.1/SIC 35)[3] |
|---|---|---|---|---|---|---|
| GVA per job[2] (2019) | 72,296 | 1,145,418 | 122,422 | 67,637 | 68,831 | 235,685 |
| Mean income (2019) | 28,666 | 87,751 | 50,504 | 28,191 | Data unavailable | 43,628 |

### GVA per job and income comparison




Source: EY analysis based on ONS and BRES data

1. The distribution of incomes may differ by sector; however, we have not specifically analysed this due to lack of publicly available data on median incomes or percentile distributions.
2. All figures are for direct jobs.
3. GVA per job data is for SIC 35.1 which includes electric power generation, transmission and distribution, mean income data is for SIC 35 which includes electricity, gas, steam and air conditioning sectors. This is due to lack of further available data at lower level SIC codes for mean income.

# GVA per job and mean income across sectors (cont'd)

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There is also a regional element to consider: 98% of direct Scottish O&G jobs are located in Aberdeen City and Aberdeenshire, and these jobs comprise 10% of all jobs in Aberdeen. The average GVA per job in Aberdeen City and Aberdeenshire outside of the O&G sector is £68.8k, which is broadly in line with the Scottish average, but significantly lower than the O&G extraction sector average. Therefore the decline of the O&G industry could disproportionately concentrate any economic downsides in Aberdeen City and Aberdeenshire.

## Considerations for energy transition

The transition away from O&G may involve investment in new opportunities in the renewables and electricity sectors, which could to some extent offset the decline in O&G production (and therefore employment, GVA and knock-on effects on the supply chain). For example, the current GVA per job generated by the electricity sector in Scotland is £236k per job, nearly 2.5 times higher than the average Scottish GVA per head in sectors outside O&G.

Further investment in directing jobs towards higher value sectors under the green transition could help mitigate losses in value and declines in average income, from the energy transition away from O&G. The energy sector[1] has a mean income of £43.6k, which is over 50% higher than the national average. It is also important to note that investment in other renewable sectors (e.g. wind) may not necessarily involve spending within the supply chain in Scotland or in the same Scottish regions as O&G, as jobs could be moved to these other industries without sufficient manufacturing being carried out locally in Scotland, hence there may be a more limited economic impact if the supply chain and direct jobs of alternative industries are not located within Scotland.

We have highlighted the relative job intensity of the O&G and energy sector. The scope of this report is to review the economic footprint of the O&G sector rather than wider energy transition; this will be considered in subsequent phases of work.

The main findings are summarised below, which will inform work in the next phase:

- GVA per job of the O&G extraction sector is significantly higher than other sectors of the economy;
- Renewable investments would need to keep up with the pace of transition away from O&G extraction, with 35,000 jobs forecast to be lost by 2030 (from 2019) due to the energy transition;
- Aberdeen is likely to feel a large amount of this impact, as 98% of direct O&G jobs are within Aberdeen City and Aberdeenshire; and
- There is a significant additional risk of higher structural unemployment and/or lower GDP in Scotland from a misaligned transition.

1. Mean income data is for SIC 35, which also includes other sub-sectors across electricity, gas, steam and air conditioning.

# The O&G extraction sector supply chain

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This section highlights the key sectors that sit within the O&G extraction supply chain. The economic contribution of these sectors is captured via the calculated indirect impact of the Scottish O&G extraction industry.

## Supply chain of O&G extraction

- The industries that supply the Scottish O&G extraction sector are listed in the table to the right. The spend by the O&G extraction industry with each of these sectors is termed "intermediate consumption". This has been estimated based on the 2016 SG Satellite Accounts, as outlined on page 36.
- Support services and machinery and equipment are the largest two sectors in Scotland's O&G extraction supply chain, comprising approximately 25% (£3.3bn) and 21% (£2.7bn) of intermediate consumption.
- Financial services is the third largest sector in the supply chain, comprising 11% (£1.4bn). This is equivalent to 15% of the total output of Scotland's financial services sector. Other key sectors include repair and maintenance, O&G extraction (inter-industry intermediate consumption) and employment services.
- There are challenges with measuring how much of the Scottish O&G extraction sector's supply chain spending takes place within Scotland. The indirect and induced impacts of this supply chain on Scotland's total GVA and employment is dependent on how much of the supply chain is located within Scotland, or elsewhere in the UK. We have assumed Scotland's share of the O&G extraction supply chain reflects Scotland's GVA and employment in each industry in the supply chain.

### Table 10: Scottish O&G extraction intermediate consumption by sector (i.e., supply chain spend by sector)

| Sector | Intermediate consumption £m | % of O&G supply chain |
|---|---:|---:|
| Mining Support | 3,298 | 25% |
| Machinery and equipment | 2,735 | 21% |
| Financial services | 1,489 | 11% |
| Repair and maintenance | 1,083 | 8% |
| O&G extraction, metal ores and other | 1,003 | 8% |
| Employment services | 578 | 4% |
| Fabricated metal | 328 | 2% |
| Water transport | 302 | 2% |
| Rental and leasing services | 269 | 2% |
| Architectural services etc | 225 | 2% |
| Air transport | 208 | 2% |
| Construction | 207 | 2% |
| Computer services | 190 | 1% |
| Iron and Steel | 180 | 1% |
| Other[2] | 1,067 | 8% |
| **Total** | **13,161** | **100%** |

Source: EY analysis based on Scottish Government Satellite accounts

1. https://www.gov.scot/publications/scottish-national-accounts-programme-whole-of-scotland-economic-accounts-project/
2. 'Other' includes: legal activities, computer, coke, petroleum and petrochemicals, head office and consulting, electricity costs (amongst other sectors).

# The importance of the O&G extraction sector in the wider economy – downstream activities

## Scottish sectors that consume O&G extraction

- The O&G extracted by the Scottish O&G industry is a key input into a number of other sectors of the Scottish economy. In particular, companies that purchase O&G as a key input into their own production, including: producers of refined oil products, the wider petrochemical sector, and energy generation. The economic contribution of this downstream activity has not been included in the scope of the calculation of the impact of the Scottish O&G sector but should be considered to give a complete picture of the importance of O&G to the Scottish economy.

### Demand for O&G along value chain


- To understand the scale of downstream activities, UK Input-Output tables[1] have been used to estimate the domestic demand for Scottish offshore O&G extraction by sector. Intermediate demand for Scotland's O&G extraction is assumed to be across the same sectors as the UK O&G extraction industry as a whole, but demand across sectors has been adjusted to total 2019 direct Scottish O&G GVA levels. The estimated intermediate demand for Scottish O&G by sector is shown in the table on the right.
- Manufacturing of petroleum products is the largest sector demanding 72% of O&G extraction output. Outside of this sector, the two largest sectors with demand for O&G extraction are the electricity and gas sectors.
- Based on the size of GVA of Scotland's industries, it is estimated that 8% of the demand for Scottish O&G extraction is from the Scottish economy. This is broadly aligned with an estimated 88% of Scottish O&G being exported (to rUK or ROW).
- The scope of this work does not include an assessment of how a contraction in O&G extraction would impact downstream sectors.
- In 2019, Scottish petroleum and petrochemical manufacturing generated GVA of £0.4bn and supported 2,000 direct jobs. The broader manufacturing of petroleum, chemical and other mineral sector (including metals) had a total GVA of £2.8bn and supported over 24,000 jobs.
- There is a risk that these sectors contract, particularly if they were unable to source O&G from outside of Scotland.
- The downstream sectors are the subject of detailed analysis in section 11.

### Table 11: Estimated demand for Scottish O&G extraction by sector

| Sector | Intermediate demand £m | % of O&G demand |
|---|---|---|
| Manufacture Of Coke And Refined Petroleum Products | 13,370 | 72% |
| Electric power generation, transmission and distribution | 1,945 | 11% |
| Manufacture of gas; distribution; steam and aircon supply | 1,788 | 10% |
| Extraction Of Crude Petroleum And Natural Gas and Mining Of Metal Ores | 440 | 2% |
| Manufacture of petrochemicals | 322 | 2% |
| Manufacture of other basic metals and casting | 218 | 1% |
| Manufacture of basic iron and steel | 101 | 1% |
| Other[2] | 259 | 1% |
| **Total** | **18,443** | **100%** |

Source: EY analysis based on ONS UK supply and use tables

1. https://www.ons.gov.uk/economy/nationalaccounts/supplyandusetables/datasets/inputoutputsupplyandusetables
2. 'Other' comprises of architectural and engineering activities , manufacturing of dyestuff and agrochemicals, repair of computers and goods, other mining and quarrying amongst other sectors.

# Conclusion

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**The O&G sector is forecast to see a 35,000 person fall in employment generated between now and 2030**

The analysis of the existing (2019) economic footprint of the ScotNS shows:

- Total Employment: 79,000 jobs (including 25k direct, 32k indirect and 22k induced), equivalent to 3% of total Scottish employment.
- Total GVA: £17.9bn (including £13.3bn direct, £2.5bn indirect and £2.0bn induced), equivalent to 10% of total Scottish GDP.

Our economic forecasts up to 2030 show:

- Employment: under the central scenario, by 2030, O&G sector employment is expected to decline to 56% of 2019 levels – to just over 44,000 jobs.
- GVA: Under the central scenario, by 2030, O&G sector GVA is expected to decline overall to £7.0bn, 39% of the 2019 level of £17.9bn.
- A 10% variation in employment and GVA multipliers would result in a 8% and 5% change in forecast employment and GVA respectively.
- A 10p.p. variation in assumption for the supply chain location would result in a 24% and 9% change in baseline employment and GVA respectively.

The impact on both employment and GVA will also vary based on SG's focus on encouraging and supporting Scottish business in the O&G extraction supply chain, which may reduce leakages to elsewhere in the UK.

**There is a risk that the transition away from O&G could leave the Scottish economy smaller, with lower average incomes**

The mean income and GVA per worker in the O&G extraction sector is significantly above the Scottish average (£88k mean income and £1.1m direct GVA per worker in O&G extraction, compared to Scottish average of £29k income and £72k GVA per worker). This is driven by the GVA of the sector being heavily linked to oil price. Therefore there is a risk that the transition away from O&G could leave the Scottish economy smaller, and with lower average incomes.

The transition away from O&G may involve investment in new opportunities in the renewables and electricity sectors, which could to some extent offset the decline in O&G extraction activity.

**Manufacturing of petroleum products and gas and electricity are the three sectors most at risk from the decline in UKCS production**

The analysis also shows:

- Supply chain: O&G extraction support services, and machinery and equipment are the two largest sectors in the supply chain, comprising 46% of intermediate consumption. This is followed by financial services which makes up 11% of the supply chain.
- Demand for O&G extraction: Manufacturing of petroleum products is the largest sector demanding 72% of O&G extraction output. A further 21% of demand is from the gas and electricity sectors. Downstream O&G manufacturing sectors[1] will also be impacted by energy transition – these sectors have a total direct GVA of £2.8bn and support over 24,000 jobs. It is possible that these sectors may be less economically viable without Scotland's O&G production. We would expect wider impacts on manufacturing sectors, particularly if they were unable to source O&G from outside of Scotland and if alternative low carbon technologies were unviable; however, we have not considered this within the scope of this study.

1. Mean income data is for SIC 35, which also includes other sub-sectors across electricity, gas, steam and air conditioning.

# 5 Greenhouse Gas Emissions overview

# Introduction and overview

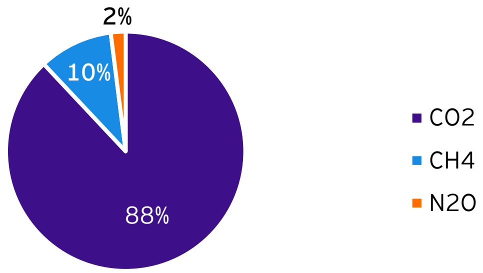


## Introduction

The Climate Change (Scotland) Act 2019 sets targets to reduce Scotland's emissions of all greenhouse gases (GHG) to net-zero by 2045. The act also established interim reduction targets of 56% by 2020, 75% by 2030 and 90% by 2040 (set against a 1990 emissions baseline). The UK O&G sector is a significant sector of the Scottish and UK economies and although still an important source of energy, the industry contributes to national GHG emissions. Detailed information on the scale of Scottish O&G emissions can be found on page 47.

GHG emissions comprise of three main components, carbon dioxide ($CO_2$), methane and nitrous oxide. The NSTA Emissions Monitoring report shows that historically $CO_2$ emissions have been the largest contributor to GHG emissions, with methane and nitrous oxide contributing lower proportions.

2018 UK upstream O&G emissions breakdown




Source: NSTA Emissions Monitoring report

The three components include:

- Carbon Dioxide ($CO_2$) – the majority of $CO_2$ arises from fuel combustion on offshore facilities. The remainder of $CO_2$ emissions arise from flaring and a small proportion is vented.
- Methane ($CH_4$) – methane emissions are associated with the venting of natural gas and inefficiencies in the flaring process. Methane has the global warming potential 27.2-29.8 times that of $CO_2$ over a 100 year period.[1]
- Nitrous Oxide ($N_2O$) – like the other gases, nitrous oxide emissions arise from fuel production and flaring. Nitrous oxide has a global warming potential of 273 times $CO_2$ over a 100 year period [1].

All three GHG components are prevalent in the ScotNS O&G industry. Although $CO_2$ represents the largest proportion of GHG emissions, methane and nitrous oxide have significant global warming potential. As a result, it is important that all three components and monitored and regulatory policies are designed to tackle each of them.

Emissions data is reported by the industry on an aggregate basis in $CO_2$ equivalent units, according to the definitions set out by the IPCC. As a result, non-carbon dioxide greenhouse gases are converted to $CO_2$ equivalent to provide an accurate representation of the global warming potential.

The O&G industry has recently increased efforts to monitor emissions data and benchmark progress towards its net zero ambitions.

| Key Term | Definition |
|---|---|
| Combustion emissions | Emissions arising from fuel combustion, used to power offshore equipment. |
| Flaring emissions | Emissions arising from gas intentionally flared from offshore facilities during the normal course of operations. |
| Venting emissions | Emissions arising from intentionally vented or unintentionally released gases into the atmosphere from offshore facilities. |

[1] IPCC AR6 WG1 Chapter 7

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## Emission Inventory and Territorial emissions

The UK's National Atmospheric Emissions Inventory (NAEI) calculates estimates of the UK's GHG emissions to provide an important picture of emissions and emission removal trends. It can be also used as a reference point for monitoring national net zero targets.

Emission inventory refers to a database that lists, by source, the amount of air pollutants discharged into the atmosphere over a time period. Governments are required to report their national GHG inventories.

These estimates, known as territorial emissions, are production-based estimates and include GHG emissions or removals from:

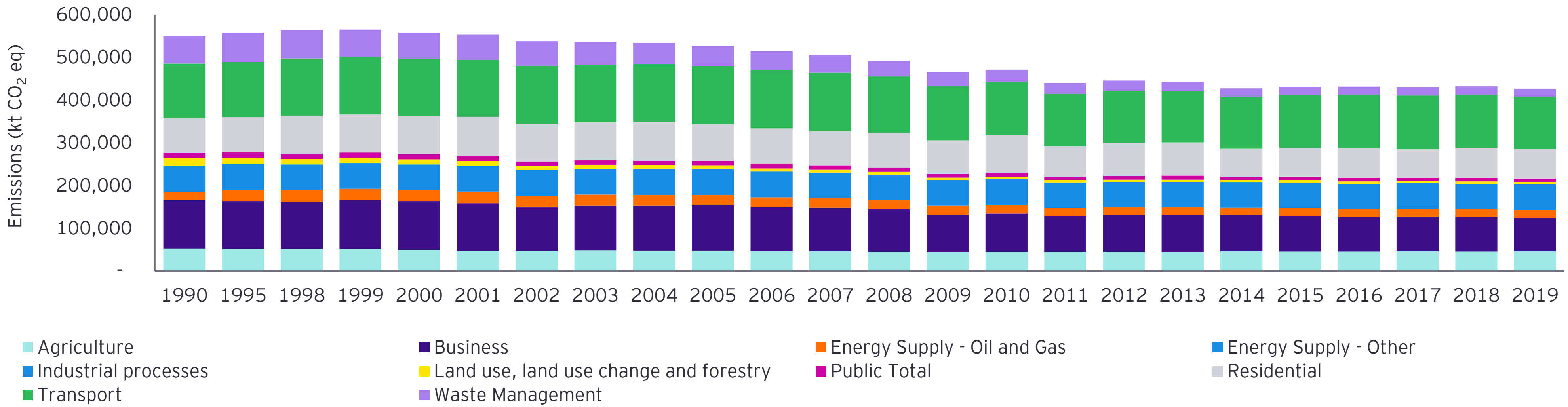
- Businesses based in the UK regardless of where in the world they are registered
- The activities of people that live in the UK as well as non-UK visitors
- Land such as forest, crop or grazing land

They exclude emissions or removals from specific sectors, including, amongst others, international air travel, international shipping and the production of goods and services that the UK imports from other countries.

The UK inventory covers the basket of seven GHGs that contribute to global warming – Carbon dioxide ($CO_2$), methane ($CH_4$). nitrous oxide ($N_2O$), hydrofluorocarbons (HFC), perfluorocarbons (PFC), sulphur hexafluoride ($SF_6$) and nitrogen trifluoride ($NF_3$). The NAEI also captures data for England, Scotland, Wales and Northern Ireland separately.

Emissions from fuel combustion for electricity and other energy production sources, and fugitive emissions from fuels (such as from mining or onshore O&G extraction activities) are included in "Energy Supply – Oil and Gas" category, shown in blue below. North Sea O&G emissions are not allocated to Scotland. Emissions of GHGs from offshore O&G exploration and production are classified within the GHG Inventory as "Unallocated" emissions and not attributed to any of the devolved administrations. The chart below shows the UK position.

### UK GHG Inventories by sector




Source: NAEI

# Introduction and overview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## GHG emissions from production versus use

Emissions arise at a number of points along the production process and during end use. The production process generally includes three stages:

- Upstream activities (the extraction of O&G)
- Midstream activities (the transportation of O&G)
- Downstream activities (the refining of O&G)

The carbon emissions associated with the O&G extracted from the ScotNS are not limited to the upstream and midstream activities (also known as Scope 1 and Scope 2 emissions). To help illustrate this point, analysis from the Carnegie Endowment states that over 80% of the carbon emissions from various oil fields in the North Sea are associated with downstream activities and end use (Scope 3 emissions).

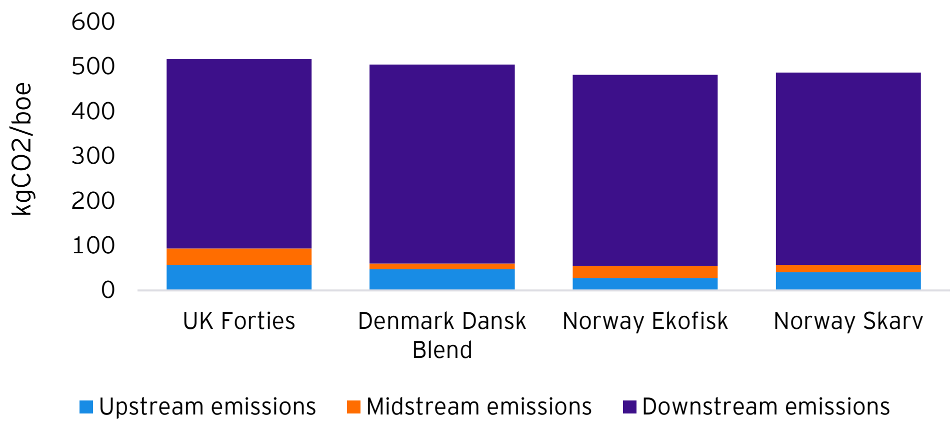
A much smaller proportion of the carbon emissions are associated with the upstream (including production) activities. Data from the NAEI also shows that UK O&G emissions and emissions related to O&G refining are significantly lower than the emissions associated with electricity and heat production. Nevertheless, these upstream carbon emissions do represent a significant source of carbon emissions.

Scope 3 emissions occur at multiple points along the supply chain and measuring them is difficult due to their indirect nature. A useful example of Scope 3 emissions relate to the indirect emissions that arise from the combustion of O&G, for example, from driving a car or heating a home. Methodologies for measuring and tracking Scope 3 emissions are in their infancy and there is no universally agreed approach to doing this. Although downstream emissions are not in scope for this review, reducing these emissions are an integral element of meeting our climate change ambitions.

The UK Government is undertaking a review to explore the compatibility of continued O&G licencing with the UK's climate change objectives. As part of this review, it was recommended that "checkpoints" be introduced to ensure that the climate change objectives are always evaluated before licencing is offered.

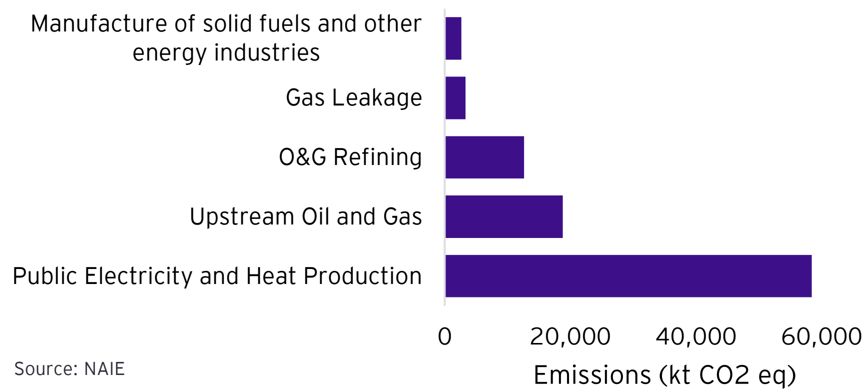
A compatibility checkpoint that incorporates Scope 3 emissions is outwith the scope of this review, but will be considered as part of future chapters of this analysis.

### Illustrative total emissions per barrel of oil




Source: Carnegie Endowment

### UK Energy supply emissions




Source: NAIE

# Historical upstream GHG emissions

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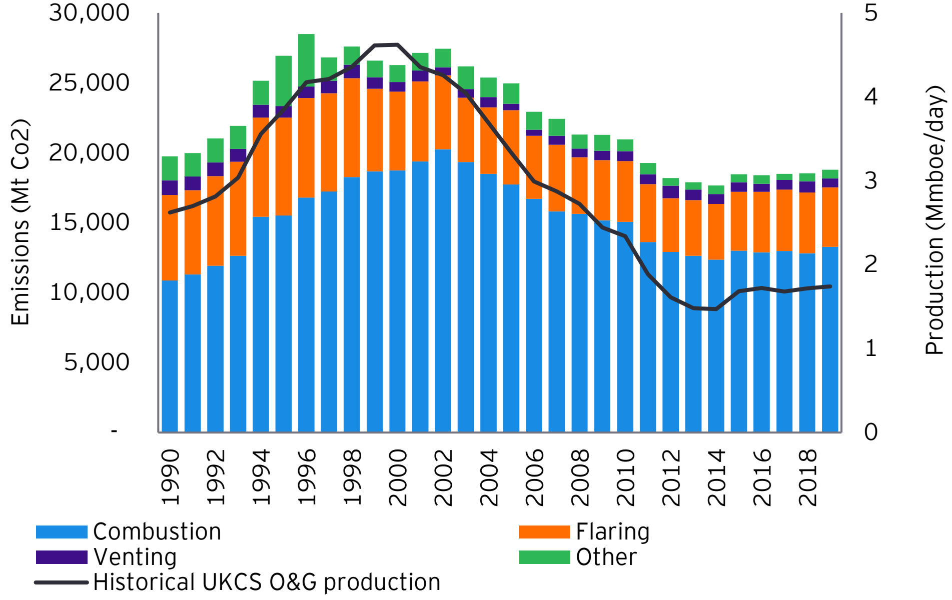
## Historical emissions arising from the UKCS production

In its 2021 Emissions Monitoring report, the NSTA explores historical GHG emissions arising from the UK upstream O&G industry (Scope 1 and 2 emissions).[1] The analysis shows:

- Historical industry emissions peaked in 1996 at 29 $MtCO_2e$, before falling to a low of 18 $MtCO_2e$ in 2014. Between 2014 and 2018, industry emissions increased by 6% to 19 $MtCO_2e$. This represented 4% of the total UK GHG emissions or (if split pro-rata) over 30% of Scottish emissions.
- Between 2018 and 2020, industry emissions fell by 11% from 19 $MtCO_2e$ to 17 $MtCO_2e$. This is corroborated by OEUK who, in its 2021 Energy Transition Outlook, provided a progress update following the launch of emissions reduction targets in 2020. Since 2018 OEUK has published emissions target data, with the analysis showing historical total Scope 1 and 2 emissions falling by 10% from 18.88$MtCO_2e$ in 2018 to 17.06$MtCO_2e$ in 2020.
- In the UK, offshore combustion was the largest source of upstream emissions, representing 68% of total emissions over this period. This represents the use of natural gas or diesel fuel in the energy intensive production process.
- Approximately 23% relates to flaring with 3% of emissions arising from venting, within the remainder associated with other "fugitive" emissions including leakage.
- The NSTA forecasts that in 2020 GHG emissions will fall by as much as 12%, caused in part by emission abatement activity but also as a result of other factors including a general reduction in O&G activity driven by the COVID-19 pandemic, a fall in commodity prices and the end-of-life shutdown of several large GHG emitters.

### Historical UK upstream GHG emissions




Source: NAEI, NSTA

The historical UKCS industry total $CO_2$ emissions indicate:

- Emissions largely correlate with the UKCS production levels, as greater production results in greater levels of GHG emission.
- As production declines, emissions fall at a slower rate as the power demands (and therefore emissions) from individual O&G assets tend to stay stable.
- Emissions are influenced by a range of operational and structural factors, which differ on a platform by platform basis. As platforms age, operational efficiency, power source and routine flaring and venting all lead to higher emissions. These are discussed in more detail on page 51.

[1] NSTA's 2021 Emissions Monitoring report utilises data from the UK National Atmospheric Emissions Inventory (NAEI), which publishes annual UK GHG figures for all sectors of the UK economy. Our analysis also adopts the relevant Intergovernmental Panel on Climate Change (IPCC) categories to extract the relevant sectors from the NAEI data.
[2] 2019 NAEI data

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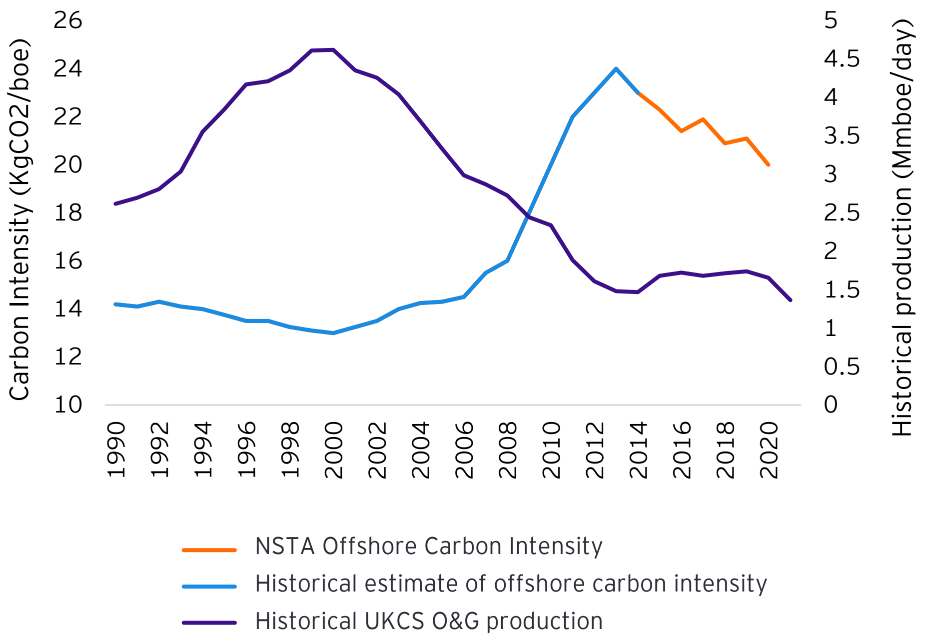
- This graph plots the historical production levels against the historical offshore upstream carbon intensity figure. It highlights the inverse relationship between the two trajectories. As production declines at a faster rate than total emissions, the carbon intensity levels increase, meaning the emissions per barrel of oil produced increases.
- The more recent downwards trend in carbon emissions intensity has arisen following a renewed focus on production and energy efficiency measures that have become more prevalent in the industry, leading to lower emissions per barrel of oil equivalent.
- Analysis by the Oxford Energy indicates that UKCS oil production is much more emission-intensive than gas production. This is driven by the lower energy-intensity of gas producing assets, particularly in the Southern North Sea (SNS), as some oil fields require complex and energy intensive production facilities. However, due to the coproduction of some O&G, obtaining reliable data is difficult.

## Historical UKCS carbon intensity




Source: NSTA and Oxford Energy "Net Zero Targets and GHG Emission Reduction in the UK and Norwegian Upstream Oil and Gas Industry"

# Factors contributing to upstream GHG emissions

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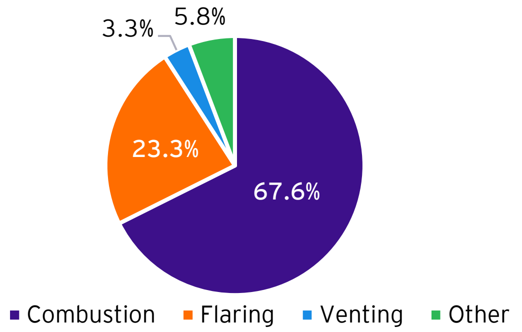
### Factors contributing to GHG in the ScotNS

The emissions profile of the O&G industry is a complex and varied landscape. This is true not only a global level, but also within the ScotNS. For example, offshore emissions vary on a platform by platform basis as the carbon intensity of individual assets differs significantly. The NSTA states that this can vary from 1kg$CO_2$/boe to 146kg$CO_2$/boe in the UK.

Offshore emissions are primarily driven by two key factors: firstly, how the asset is powered (combustion emissions) and, secondly, operational considerations such as flaring and venting.

The analysis of the historical UKCS emissions shows that the largest contributor to emissions is offshore combustion, followed by flaring and venting.

**Historical contributors to GHG emissions**




Source: NAEI

### Offshore combustion – how O&G offshore production is powered

A range of factors contribute to the energy profile (and therefore emissions profile) of offshore facilities. Firstly, combustion emissions are impacted by the complexity of the O&G field/reservoir, where the viscosity of the crude oil, geology, water depth, and pressure requirements all result in different energy requirements and lead to different assets having different energy demands and therefore emission profiles.

Large and complex production facilities are more energy and emissions intensive.

[1] IPCC AR6 WG1 Chapter 7

Moreover, the age of the facilities impacts emissions intensities, as older platforms with less efficient equipment result in higher emissions. Older facilities are also much more expensive to electrify to reduce emissions levels.

Analysis undertaken by the NSTA shows that, depending on the platform type, the carbon intensity for older assets can be 2.5 to 3.5 times higher than newer platforms.

**Table 12: 2020 Carbon intensity (kg$CO_2$/boe) by installation age and platform type**

| Installation Age | Small platforms | Floating | Large Platforms |
|---|---|---|---|
| 0-10 years | 6 | 16 | 13 |
| 11-25 years | 17 | 41 | 15 |
| > 25 years | 22 | 40 | 47 |

*Source: NSTA*

In 2020, over 70% (or 68% using the historical average) of all offshore upstream O&G emissions arose from consuming natural gas or diesel fuel in the energy intensive production process, including the processing and transportation of O&G. As established fields become depleted, as is the case in the ScotNS (and the whole of the UKCS), the energy intensity of production tends to increase.

In the UKCS, offshore O&G production is currently entirely powered by generation on platforms, rather than through subsea electricity cables connected to the onshore network. The exception is the now decommissioned Beatrice oil field that was connected to the onshore network to supplement gas-fired electricity generation.

**Key conclusion**

Historically 68% of all offshore upstream O&G emissions arose from consuming natural gas or diesel fuel in the energy intensive production process, including the processing and transportation of O&G.

# Factors contributing to upstream GHG emissions



### How O&G offshore production is powered (cont'd)

Powering offshore production has an energy intensity of 460kg$CO_2$/KWh using an offshore gas turbine or 602kg$CO_2$/KWh for an offshore diesel engine (based on analysis for the NSTA Energy Integration project). This compares to the carbon intensity of the UK electricity grid of 181kg$CO_2$/KWh. To combat this, the emissions intensity may be reduced by:

- Utilising onshore grid power to bring the platform emissions intensity in line with the wider system.
- Connecting to offshore wind capacity, including areas close to upstream operations.

Analysis from Rystad Energy highlighted the positive impact that platform electrification can have on the carbon intensity per boe. For example, Norway's electrified platforms (and other historical emissions reducing measures) contribute to a lower carbon intensity figure of 8kg$CO_2$/boe. Norway also benefits from having less carbon intensive onshore generation and tighter emissions standards, both of which help to drive down the carbon intensity figure. Where offshore power is supplied by the onshore network, it is provided by low carbon hydroelectricity that accounts for more than 97% of this power generation. As a result, even if UK onshore grid connections were possible, the carbon intensity of the electrification would align with the UK's electricity grid carbon intensity and not the lower carbon intensity levels experienced in Norway (c25kg$CO_2$/KWh).

Another significant factor driving the Norwegian figures is the historical political pressure to reduce offshore emissions. In 1996 the Norwegian government required new fields to consider onshore power supply. Recent technologies advances have also extended the scope of power-from-shore; however, it was the ambitious national decarbonisation targets that stimulated the reduced Norwegian offshore emissions. In contrast, the UK progress on developer power from shore and the integration of offshore renewables has been much slower.

There are significant technical and economic challenges associated with platform electrification, including the economic viability of utilising power from the onshore grid. This is due to the cost of platform modification and the high cost of onshore electricity.

A 2020 report by the NSTA (UKCS Energy Integration) concluded that platform electrification is essential to currenting sector production and could abate as much as 2-3Mt$CO_2$ p.a. by 2030 (or approximately 10-20% of current emissions).

Power generation emissions in $CO_2$e terms are 97% $CO_2$, 1% $CH_4$ and 2% $N_2O$, meaning that platform electrification will primarily reduce $CO_2$ emissions.

**Key conclusion**

The NSTA states that platform electrification can abate as much as 2-3Mt$CO_2$ p.a. by 2030 (or approximately 10-20% of current emissions).

In section 12 we explore other global examples of O&G producing countries to provide further context for the UK and Norway's emissions profile. Additionally, the analysis overleaf explores the measures the UK Government and the O&G industry is adopting to reduce future emissions. Before exploring these measures, however, another set of operational practices that contribute to the industry's emissions footprint must be understood.

### Flaring and Venting

Gas flaring and venting is a standard industry practice and takes place for operational and safety reasons. In the UK, the North Sea Transition Deal (NSTD) aims to drive down flaring and venting to the lowest possible levels and prevent new developments from undertaking this activity. After power generation, routine flaring and venting represents the largest contribution to upstream O&G emissions. On average, flaring and venting accounted for 3kg$CO_2$/boe in the UKCS.

This is also a globally recognised problem. The World Bank's Zero Routine Flaring (ZRF) initiative commits governments and the industry to end routine flaring no later than 2030.

Analysis undertaken by the NSTA shows that in 2019, of the natural gas produced from the UKCS, 88% was exported to the market, 9% utilised offshore as fuel and the remaining 3% was either flared or vented. Of that 3%, 98% was flared and 2% was vented.

Unlike platform electrification, reducing routine flaring and venting is not dependant on complex commercial decisions and therefore is more easily adopted and in 2021 the NSTA issued new guidance that will end routine flaring and venting by 2030.

[1] NSTA_ukcs_flaring_venting_report_2020_pdf.pdf (NSTAuthority.co.uk)
[2] NSTA Emissions Monitoring Report

# Future upstream GHG emissions – North Sea Transition Deal



## North Sea Transition Deal

Before exploring future GHG emissions trends in the UKCS and the ScotNS, the impact of the NSTD must be considered. The NSTD is an agreement between the UK government and the UK O&G sector that aims to support the energy transition of the industry.

The deal aims to make an absolute reduction in emissions from O&G production of 10% by 2025, 25% by 2027 and 50% by 2030 (against a baseline of emissions in 2018). The absolute reduction means that the targets are not linked to the level of production in the North Sea. Additionally, the deal sets out the industry's commitment to reduce carbon emissions but does not make predictions on future O&G production levels or quantify the level of emissions abatement activity the industry was willing to make. The deal commits the industry to GHG emissions by:

- Supporting platform electrification
- Reducing emissions from flaring and venting
- Retrofitting platforms with more energy efficient equipment
- Investing in Carbon Capture Usage and Storage (CCUS)
- Supporting supply chain and jobs transformation.

If these commitments are implemented, the NSTD would help shape future UK O&G operations and emissions. The deal also assumes that O&G will continue to be a central element of the UK's energy supply, but acknowledges that production will be at a significantly reduced rate due to the decline in the output in the basins.

The NSTD "One year on" report was published in March 2022. It includes commitments from the UK to support domestic energy supplies and encourage continued investment in the sector, while minimising production emissions and setting a clear path to net zero.

**What are the implications of undertaking the NSTD interventions**

While aspirational, achieving the emission targets will require the delivery of the complex NSTD commitments. To achieve this, large scale investment is needed in offshore renewable resources, equipment, technology and infrastructure to enable large scale electrification to take place.

The commercial decision to partly or fully electrify assets will also be impacted by a range of factors, including:

- The future life of the assets – some brownfield platforms have short remaining lifetimes and it will not be commercially viable to decarbonise them.
- Some platforms are floating platforms and may not be able to bear the weight of infrastructure needed for a power connection.
- The impact of declining industry-wide production and estimates of future activity.
- The cost of mechanisms for delivering power.
- The need to meet upfront infrastructure costs and the ability to work with offshore wind providers to share these costs.

There are no detailed estimates of the costs of meeting these targets and the feasibility of the routes has not been fully explored. The large scale electrification of the ScotNS is considered technically feasible by the OEUK but further analysis is required before the commercial viability of offshore electrification is fully understood.

Crown Estate Scotland has launched the Innovation and Targeted Oil and Gas (INTOG) leasing round to support offshore electrification. This is a process by which developers will be able to apply for the rights to build offshore wind farms specifically for the purpose of providing low carbon electricity to power O&G installations and help to decarbonise the sector. INTOG provides an opportunity for offshore wind projects to connect to O&G infrastructure to electrify the production facilities. This will negate the need for grid connections. Importantly, it also provides an attractive opportunity for O&G operators to diversify and establish themselves in offshore renewables.

Another complication with the NSTD targets is that the deal does not quantify the level of emissions abatement that each intervention will make. For example, is it more beneficial to focus investment on platform electrification or operational considerations such as flaring and venting? As a result, it is not clear what activities need to be prioritised.

Lastly, the NSTD does not clarify the relationship between the declining oil production forecast and the emission reduction targets. As a result, forecast carbon intensity per boe analysis is not clearly presented. For this reason, we have explored this relationship and its implications for a ScotNS emission forecast further overleaf.

# Future upstream GHG emissions – ScotNS forecast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## ScotNS emissions forecast

Total future ScotNS emissions will be determined by two key variables:

- Production levels
- Carbon emissions per boe and the ability to reduce emissions through abatement activity

No publicly available Scottish O&G upstream emissions forecast has been published that differentiates production from the emissions reduction activities.

### Impact of production on forecast emissions

The natural decline in the ScotNS is the main contributing factor to the decline of ScotNS emissions. To illustrate the correlation between ScotNS forecast production levels and the NSTD emissions reduction targets, we have plotted these two items against each other. The ScotNS emissions targets have been calculated as percentages of the 2018 historical emissions figure.

This shows a decline rate that correlates with the downward trend in the production forecast for the ScotNS. OEUK emissions analysis also shows that direct GHG emissions have a strong correlation to UK O&G production. Although emissions projections are complex and influenced by a range of factors, the analysis demonstrates that the natural decline in the ScotNS will have a significant impact on the reduction in upstream emissions arising from the industry.

## Impact of emissions abatement activity

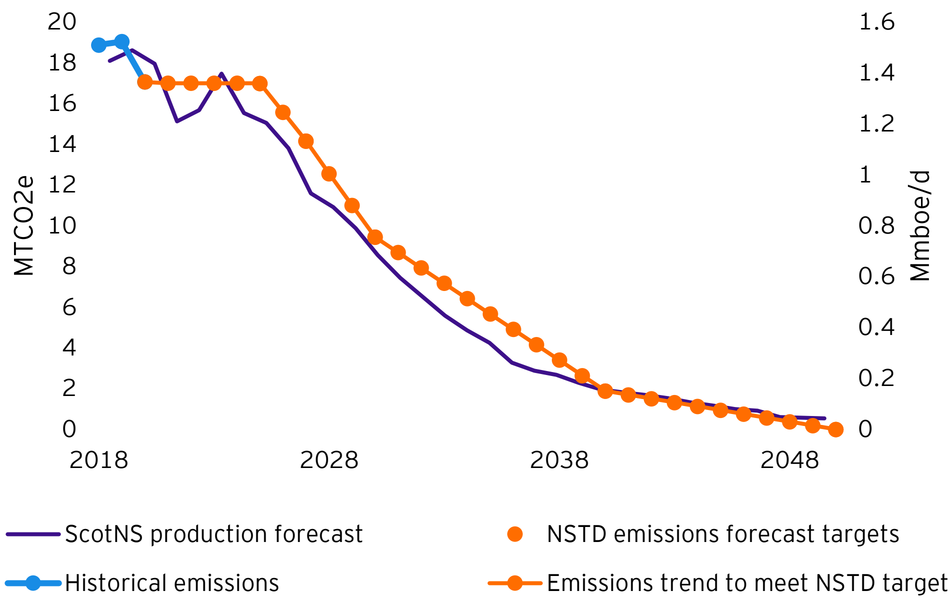
Importantly, future emissions are also expected to fall as a result of carbon abatement activity. This will include the electrification of installations, the phasing out of routine flaring and venting, the implementation of a Methane Action Plan and the phasing out of high-emissions assets.

This will reduce the emissions intensity per boe so that, even as production falls, the emissions will fall at a faster rate.

Analysis by the NSTA shows that, at a UKCS level, platform electrification will play a significant role in the industry meeting the NSTD emissions reduction targets for 2030. Between electrification project start-up and 2030, the analysis estimates that at a UK level, between 2 and 8 $MtCO_2e$ will be abated. Additionally emissions abatement from the Zero Routine Flaring 2030 policy will also play a significant role in reducing emissions and contributing to these factors.

Examples of international emissions abatement activity, such as Norwegian platform electrification, demonstrate that carbon emissions intensity per boe can be significantly reduced below the current UKCS average. As a result, there is the opportunity to continue to reduce the emissions trajectory below current forecast emissions.

### ScotNS emissions and production forecast (medium case)



# Global emissions



## Global Emission Intensity and projections

To help contextualise the UKCS and ScotNS emissions position, we have explored the offshore emissions profile of other O&G producing nations. The graph below presents the upstream crude oil global country level carbon intensity estimates. The analysis includes countries with greater than 0.1% of global oil production and is based on volume weighted average upstream GHG intensities in $gCO_2eq/MJ$.

### Factors influencing global carbon intensity levels

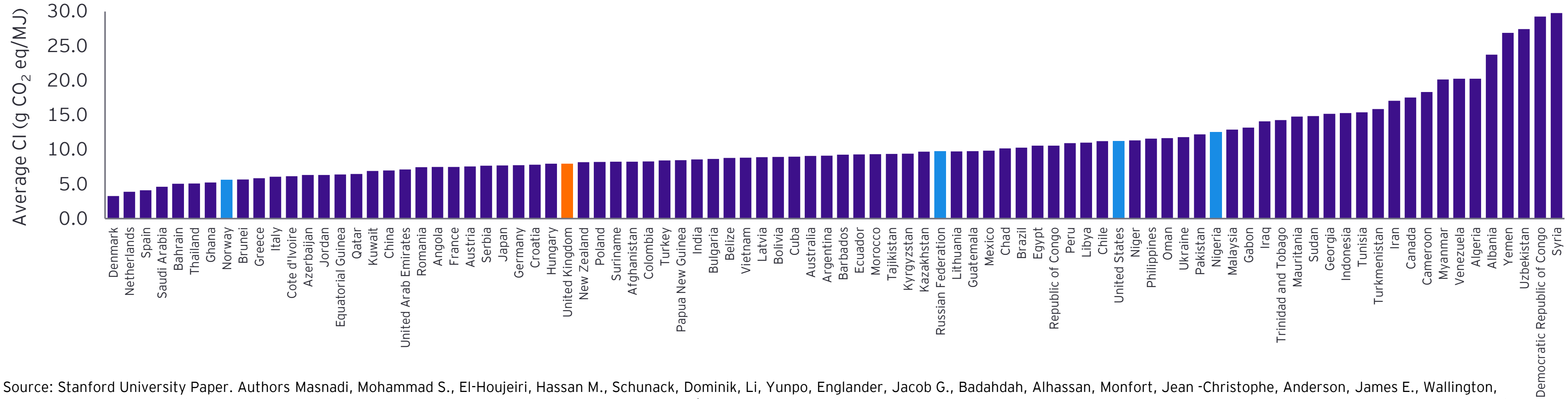
The analysis shows that the UK has an average carbon intensity figure of 7.9$gCO_2eq/MJ$, compared to the global average of 10.3$gCO_2eq/MJ$. Global carbon intensity levels range from 3.3$gCO_2eq/MJ$ (Denmark) to 29.8$gCO_2eq/MJ$ (Syria), putting the UK in the lower end of the range. The factors that determine the carbon intensity levels are varied and include:

- Flaring and venting – Research by Stanford University highlights that flaring and venting practices have a considerable influence on a country's carbon intensity.

Countries that produce light crude oil have some of the highest carbon intensity figures (e.g., Algeria at 20.3$gCO_2eq/MJ$) due to their routine flaring practices. Conversely, Saudi Arabia has relatively low levels (4.6$gCO_2eq/MJ$) with lower flaring activity and less energy intensive extraction processes. As a result, promoting regulatory processes to limit and restrict routine flaring and venting will result in significant reductions in carbon intensity levels.

- Location and geography – The research also shows a country's geography and geology play an important role. In the case of Canada (where a high share of production comes from oil sands) heavy oil produced by onshore facilities is more energy-intensive, leading to larger carbon emissions.
- Aging platforms wells – Countries such as Indonesia (15.3$gCO_2eq/MJ$), Oman (11.7$gCO_2eq/MJ$) and parts of the USA like California (11.3$gCO_2eq/MJ$), all have aging wells and energy intensive "enhanced oil recovery" processes that contributes to higher than average intensity levels.

### Estimated global upstream crude oil carbon intensity (2015)




Source: Stanford University Paper. Authors Masnadi, Mohammad S., El-Houjeiri, Hassan M., Schunack, Dominik, Li, Yunpo, Englander, Jacob G., Badahdah, Alhassan, Monfort, Jean -Christophe, Anderson, James E., Wallington, Timothy J., Bergerson, Joule A., Gordon, Deborah, Koomey, Jonathan, Przesmitzki, Steven, Azevedo, Inês L., Bi, Xiaotao T., Duffy, James E., Heath, Garvin A., Keoleian, Gregory A., McGlade, Christophe, Meehan, D. Nathan, Yeh, Sonia, You, Fengqi, Wang, Michael, and Brandt, Adam R. Global carbon intensity of crude oil production. United States: N. p., 2018. Web. doi:10.1126/science.aar6859.

# Global emissions (cont'd)



## Global emission intensity and projections (cont'd)

Norway has taken significant steps to reduce emissions from its basin. Eight fields in the Norwegian continental shelf are partly or fully electrified and another eight fields in the country have sanctioned electrification programmes; further, gas flaring has been banned in Norway.

The analysis indicates a range of factors that impact countries' carbon intensity levels. As a result, the actions that can be taken to reduce emissions levels depend on a country's circumstances, and Scotland's position will be different from other countries around the world.

Despite the UKCS's complex geography and operating conditions, it has a carbon intensity level lower than the global average and many other offshore O&G producing basins; however, additional emissions abatement activity would provide further opportunities to decarbonise the basin.

Although this may indicate that there are opportunities to reduce the UK and Scotland's carbon intensity level, the operational considerations of O&G extraction in the ScotNS make this comparison difficult. For example, countries with large levels of onshore activity will have a lower carbon intensity than the ScotNS, where deep water or complex geology change the energy and emissions profile of the sector.

International benchmarking must also acknowledge differences in industry regulation, fiscal regimes, carbon taxes and the role of private sector operators in the country. For example, the Norwegian continental shelf has been subject to a carbon tax since 1991, helping to encourage Norway's lower carbon intensity levels. Norway also has tighter regulations on the use of flaring. Historically, minimal state intervention in the UK has led to multiple operators investing in the UKCS, meaning no single organisation has dominated the landscape. Conversely, this fragmentation does not exist in Norway with the state owned Equinor (formerly Statoil) playing a central role in the Norwegian continental shelf. This has helped reinforce the regulatory framework around emissions control. These sorts of factors mean that measures needed to achieve lower emissions differ on a country by country basis, but Scotland should seek to learn lessons from countries such as Norway that provide more meaningful comparisons.

The comparison with Norway shows that basins with similar challenging geographical and operating conditions can have different emissions intensities, but measures can be introduced to support the decarbonisation of the sector. Norway's success stems from tighter regulatory control over emissions and being able to benefit from onshore grid connections utilising decarbonised onshore electricity. Therefore, to decarbonise the UKCS further, the industry must pursue measures to tackle the two key contributing factors to emissions, namely the electrification of offshore platforms the reduction in flaring and venting activity.

## Scotland's major sources of crude oil import

As discussed in Section 8, Scotland imports crude oil from several countries, with Nigeria, USA, Russia and Norway representing the largest shares. With emissions intensities of 12.6, 11.3, 9.7 and 5.6 $gCO_2eq/MJ$ respectively, the emissions intensities of these countries differ from the UKCS average and, apart from Norway, are all higher than the UK.

This would suggest that the emissions associated with importing crude oil from Nigeria, Russia and the USA are greater than the emissions associated with the crude oil extracted from the UKCS.

Conversely, crude oil imported from Norway would result in imports with lower carbon intensities.

# Greenhouse Gas Emissions conclusion



## Conclusion

Scotland has ambitious climate change targets, and although upstream emissions arising from O&G production in the ScotNS represent a small proportion of the total emissions produced from a barrel of oil, the UKCS has produced significant levels of GHG emissions, especially in recent decades. All GHG components, including carbon dioxide, methane and nitrous oxide are produced by the offshore O&G industry and must be addressed.

GHG emissions arising from the ScotNS are complex and are impacted by a range of factors, including the location of the asset, its age, how it is powered and other operational factors. This factors result in emissions intensities, changing on an asset by asset basis, but it also means that there are different levers that will impact the industry's ability to decarbonise the sector. Although emissions are impacted by a range of factors, historical upstream O&G emissions demonstrate that 68% of emissions are associated with offshore combustion, with a further 23% associated with flaring. As a result, continued action to tackle these sources of emissions will help to decarbonise upstream O&G activity.

The NSTD aims to make an absolute reduction in emissions from O&G production of 10% by 2025, 25% by 2027 and 50% by 2030 (against a baseline of emissions in 2018). The absolute reduction means that the targets are not linked to the level of production in the North Sea. Our analysis shows that the natural decline in the ScotNS will be the most significant factor in meeting the goals set out in the NSTD. Emissions from new fields or new developments will slow this decline, unless further abatement activity was to take place. The NSTD assumes that emissions from new developments or future discoveries will need to be kept within the overall industry emissions reduction targets.

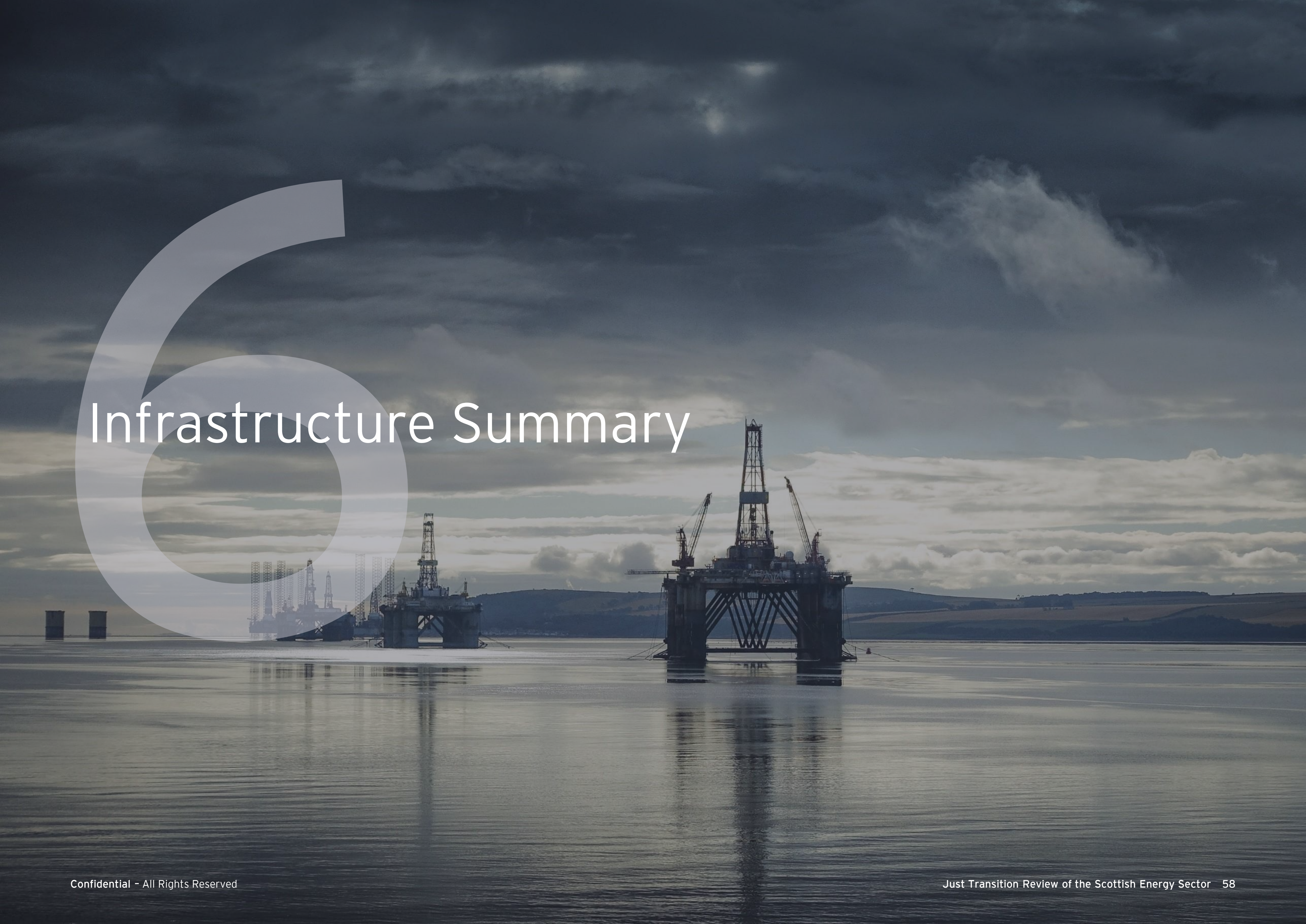
Generally, additional emissions abatement activity provides further opportunities to decarbonise the sector and help meet the more ambitious NSTD emission reduction targets. However, activities such as platform electrification come with operational and commercial challenges that have not been extensively addressed. The activities require significant amounts of capital funding, have dependencies on other areas of the energy sector and requires a medium term commitment on future extraction.

As demand is the biggest driver of GHG emissions relating to O&G, any decline in ScotNS production is unlikely to reduce overall GHG emissions unless there is also significant change to global demand. The average carbon intensity of imported crude oil is higher than that of ScotNS production, and so there is potential for GHG emissions to increase should production decline to a level where imports increase to meet demand. However, the data suggests that a reduction in ScotNS production is more likely to cause a reduction in exports in the short term, which would actually result in a reduction of the GHG emissions associated with transportation. Existing levels of imports and exports are not directly correlated to declining production, but rather are driven by wider global oil market factors. As a result, future import and export trends and any resulting GHG emissions impact is very difficult to predict.

### Key conclusion

Relative to other basins and particularly given the geology, the ScotNS has relatively low emissions. Emissions will also decline as production declines. However, more can be done to reduce emissions per boe by electrification and by preventing flaring and venting, as the example of Norway demonstrates.

The emissions associated with importing crude oil from Nigeria, Russia and the USA are greater than the emissions associated with the crude oil extracted from the UKCS.



# 6 Infrastructure Summary

# Introduction and overview



## Overview of UKCS/ScotNS infrastructure landscape

North Sea O&G is extracted and brought to shore through an extensive chain of infrastructure. This starts with the production wells, with O&G transported through the offshore platforms, floating production storage and offloading (FPSO) vessels, or sub-sea production systems and pipelines to the onshore terminals. It is an extensive chain of assets, the ownership model of which has developed and became more complex over time.

New opportunities for investment in exploration and development continue to be found, especially in the WoS basin. In order to achieve government and industry climate change targets, these new investments will need to deploy innovations such as electrification of production and establishing more efficient production with reduced GHG emissions, as described in Section 5.

That said, the North Sea is a mature hydrocarbon basin, with production having peaked around the turn of the century. Production is expected to continue to decline, and a number of fields are approaching the end of their economic useful life.

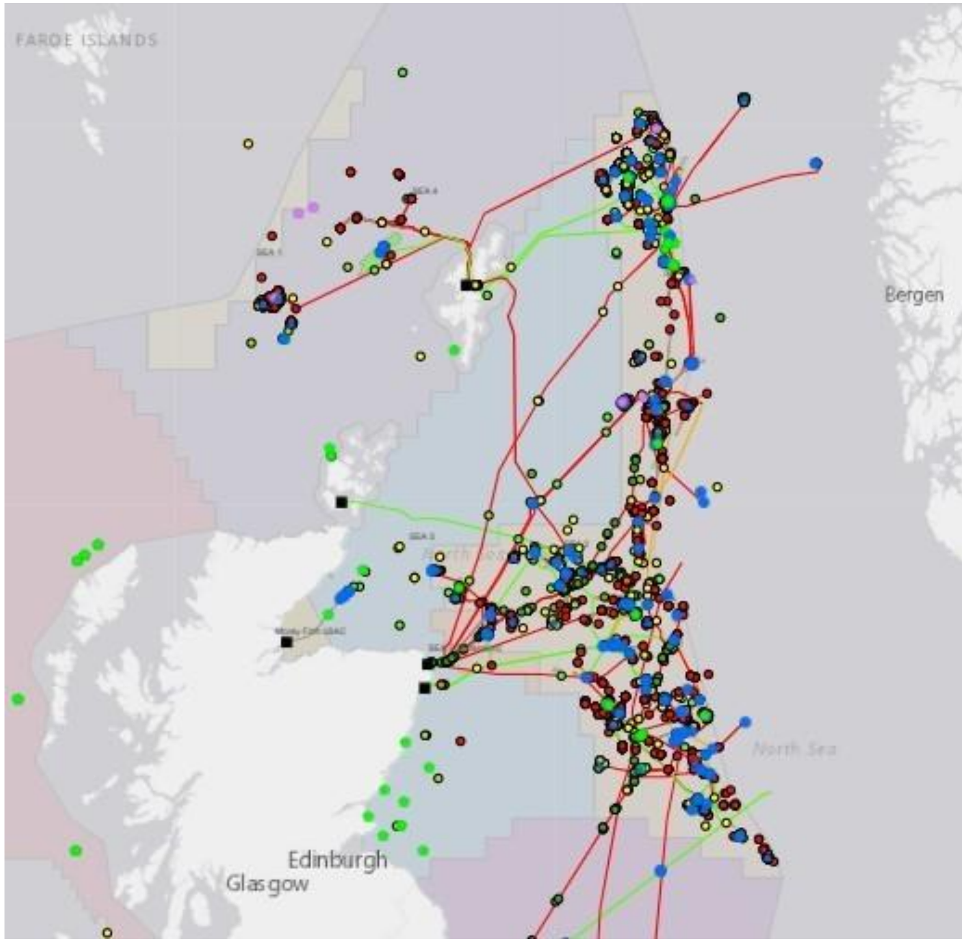
Owners of offshore O&G infrastructure must fulfil their obligations to decommission assets and remediate the marine environment, but opportunities may exist in relation to some installations to re-purpose elements of offshore infrastructure to offshore wind, hydrogen production, and carbon capture and storage.

Although it is not without its challenges, the growth of an integrated energy basin in the ScotNS represents an opportunity for elements of the O&G infrastructure to be re-purposed and re-used, bringing economic benefits to the energy industries and to Scotland.

## The extent of O&G infrastructure in the ScotNS

The map on the right, generated using the NSTA's open data, illustrates the extent of O&G infrastructure in the North Sea, including offshore platforms (blue dots), wellheads (red dots), and pipelines (red line = gas, Green line = oil, orange line = mixed hydrocarbons).

## The extent of O&G infrastructure in the ScotNS




Source: NSTA maps;
https://www.arcgis.com/apps/webappviewer/index.html?id=f4b1ea5802944a55aa4a9df0184205a5

# Existing ScotNS infrastructure assets



## Overview of existing UKCS/ScotNS infrastructure assets

Although it is challenging to derive precise figures for assets in the ScotNS, the table below uses the NSTA's open data and reports to give an indication of the scale of current O&G infrastructure in the North Sea. The value of these assets to their owners is the future cash flows associated with them – that is, the money that they will make from the hydrocarbons produced; however, this is difficult to determine because of commodity price volatility.

| Asset type | Asset description | Estimate of scale of asset type in the ScotNS* |
|---|---|---|
| Wells | ▸ Wells are used to explore for and extract hydrocarbons from O&G reservoirs. Wellheads provides the structural and pressure-containing interface for the drilling and production equipment on active wells. | 570 active wellheads; 122 not in use wellheads;<br>34 abandoned wellheads; 72 removed wellheads. |
| Platforms | ▸ Offshore facilities used to produce, process and in some instances store O&G.<br>▸ May be fixed to the seabed or floating semi-submerged.<br>▸ Total also includes accommodation platforms. | 87 fixed installations |
| Floating Production Storage and Offloading (FPSO) vessels | ▸ Floating offshore facilities for the production and processing of hydrocarbons and for the storage of oil.<br>▸ Tend to be used in remote or deep water areas.<br>▸ ScotNS also includes some Floating Storage and Offloading (FSO) vessels, which do not have the capability for oil or gas processing. | 16 FPSOs (although located in Scotland, these assets are geographically mobile)<br>2 FSOs |
| Subsea production systems | ▸ Systems used to extract hydrocarbons at the seafloor and then linked to a production platform. Wells are drilled by a moveable rig, and instead of building a production platform for that well, the extracted natural gas and oil are transported by riser or undersea pipeline to an existing production platform.<br>▸ Comprise of the well system, the production system (includes protective structures, manifolds, towheads, processing systems), and the pipeline. | NSTA estimates over 75,000 tonnes of subsea infrastructure in the UKCS.<br>Current ScotNS total includes:<br>▸ 295 manifolds<br>▸ 71 towheads<br>▸ 84 riser bases (subsea support structures) |
| Pipelines | ▸ Used to transport O&G from offshore facilities to onshore terminals.<br>▸ Includes intra-field transfer and export lines often shared by multiple fields. | More than 20,000 km of pipeline in UKCS, the majority of which is in the ScotNS |
| Onshore terminals | ▸ St Fergus Gas Terminal<br>▸ Cruden Bay Oil Terminal<br>▸ Sullom Voe Oil Terminal (Shetland).<br>▸ Flotta Oil Terminal (Orkney Islands)<br>▸ Nigg Oil Terminal, Port of Cromarty Firth | Five O&G terminals connected to ScotNS pipeline network |

* For the purposes of this analysis, ScotNS assumed to be all active and pre-commissioned NS infrastructure to the north of latitude 55.80.
Sources: NSTA Open Data; https://data-NSTAuthority.opendata.arcgis.com/
NSTA UKCS Decommissioning Cost Estimate 2021 https://www.NSTAuthority.co.uk/media/7680/ukcs_decomm_cost_estimate_2021_single_master.pdf

# ScotNS pipelines



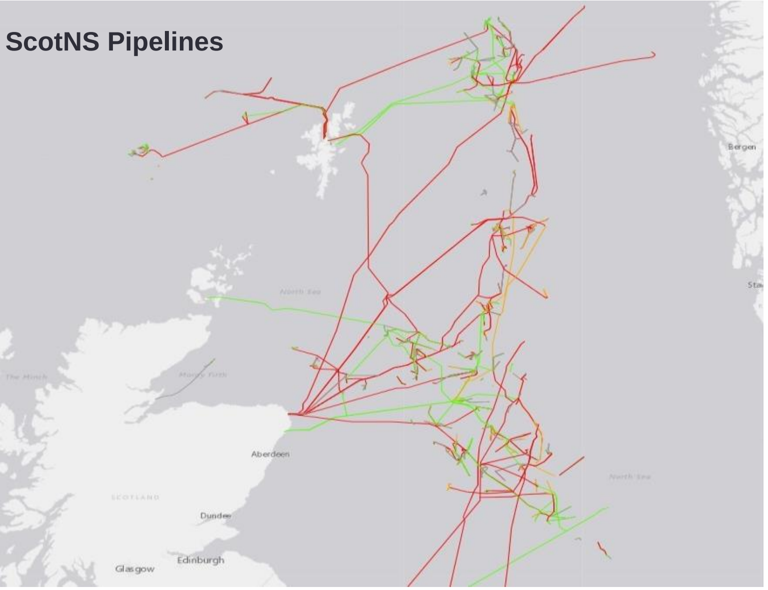
## Overview of UKCS/ScotNS infrastructure landscape

The North Sea's O&G infrastructure represents an opportunity in the transition to an integrated energy basin. It offers existing physical links to offshore sites with potential for net zero interventions and facilities that can be re-purposed and re-used to deliver the net zero economy.

### Key conclusion

The O&G industry's ownership and commercial models are complex and varied, presenting challenges for both decommissioning and re-use/repurposing

Here, the issue is illustrated by the example of a key element in the infrastructure chain: pipelines.




Source: NSTA maps; https://www.arcgis.com/apps/webappviewer/index.html?id=f4b1ea5802944a55aa4a9df0184205a5

## The complexities of pipeline ownership

O&G extracted from the North Sea is transferred to the mainland most commonly via pipelines on the seabed to onshore terminals, from where it is transported to a refinery or end user via onshore pipeline, vehicle or, from the Flotta and Sullom Voe terminals, distributed worldwide by tanker.

In the early years of the UKCS O&G industry, upstream O&G companies typically owned the midstream transportation and storage assets (pipelines and terminals). However, it was soon established that it was inefficient to construct new midstream assets for all fields, particularly as smaller fields were discovered. This resulted in a system of third party access, the principles and procedures of which are set out in the voluntary industry Code of Practice on Access, with new fields paying a tariff for use of existing infrastructure.

The 2014 Wood Review noted the need for independent transporting and processing of third party production to maximise recovery. The system developed with midstream assets being owned by one or more companies, a designated operator, and third party users of the infrastructure paying tariffs.

A fall in oil prices also encouraged owners of midstream assets to dispose of assets to generate cash, resulting in independent entities owning midstream assets: the Frigg gas processing and transportation system was sold by Total to North Sea Midstream Partners (NSMP) in 2016. BP sold the Central Area Transmission System (CATS) pipeline to Antin Infrastructure Partners; while Ancala Midstream Acquisitions Limited acquired Apache's interests in the Scottish Area Gas Evacuation (SAGE) System and the Beryl Gas Pipeline.

Examples of joint-ownership also exist. The Ninian pipeline, which runs from the Ninian Central Platform in the North Sea to the Sullom Voe Terminal in Shetland Islands, is jointly owned by six different companies. In such circumstances, several parties would need to agree to any changes in use.

In contrast, Ineos FPS has exclusive ownership of the Forties pipeline system which terminates at Grangemouth, and operates the 'Unity Platform' in the North Sea. The Unity platform is a gathering hub which receives crude O&G via six incoming pipelines connected to other offshore installations not operated by Ineos. These crude oil streams are combined into the FPS Sealine pipeline to the Cruden Bay Terminal, from where it is piped to Grangemouth.

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## Pipeline ownership (cont'd)

Ineos is responsible for the operation, repair and maintenance of the Forties pipeline and, in return, is paid a tariff charge by producers who use it. Any downtime of this asset due to maintenance or failure can mean a costly cessation of production at the interconnected fields. In 2019 Ineos announced a £500m investment to extend the asset's life to 2040s.

The current third party access regime, underpinned by a voluntary industry code, allows a party that seeks access to upstream infrastructure and cannot agree such access with the owner to apply to the NSTA for a notice granting the relevant rights.

## Challenges of these complexities for the integrated energy basin

The above examples demonstrate the complexities of pipeline ownership and the obligations of pipeline owners to a number of customers. The principal pipelines that bring hydrocarbons onshore link to connections to multiple fields, often with different owners and varying expected lifespans. As a result, third parties may have overlapping rights to use assets, and would be entitled to seek significant compensation were that access denied.

The decommissioning or re-purposing of particular pipeline assets is complex due to these wider implications for other parties. Moves towards re-using existing assets in an integrated energy basin will require a high level of coordination and cooperation between government, operators and contractors. For an asset to be taken out of O&G use, all parties with a right to use it would need to agree to change in use, and those with reserves still to extract would require compensation.

These complexities exist across all asset types. Participation in the upstream O&G sector is dependent upon either owning a licence or acquiring an interest in existing assets. Licences give specific rights to blocks within the North Sea, and the kind of licence obtained dictates the activity that can be undertaken by the holder and for what duration. With the consent of the NSTA licences can be sold, transferred, assigned or otherwise dealt in; for example, in 2019 Chevron sold its North Sea assets to Ithaca, while in 2021 United O&G sold two licences to Quatro Energy, a newly incorporated company. This has led to a fragmented patchwork of different owners – not just a small group of major players - which will make coordination and cooperation more challenging.

## ScotNS decommissioning

The ScotNS is an aging basin with a number of fields approaching the end of their economic useful life and production expected to continue to decline. Statutory requirements mean that owners of offshore O&G infrastructure are obligated to decommission their assets and remediate the marine environment in a way that is consistent with government policy.

Decommissioning activity is intensifying and consuming a greater proportion of the industry's focus and resources. OEUK estimates that decommissioning spend in the North Sea could reach £16.6bn over the next decade, the majority of which – £13.1bn – relates to assets in the ScotNS (NNS/WoS: £5.9bn, CNS: £7.2bn).

The development of greener ways to decommission and the identification of circular economy efficiencies therefore represent potentially significant opportunities arising from the energy transition. Decommissioning is an energy intensive exercise, so ways of reducing its carbon footprint have the potential to deliver considerable benefits.

The NSTA's Decommissioning Strategy (May 2021) is designed to support the O&G industry in delivering the obligations placed upon it, to enable the achievement of the UK Government's commitment of net zero emissions by 2050. The Decommissioning Strategy has four complementary areas of focus, with the target of reducing decommissioning cost estimates by 35% by the end of 2022:

- Planning for decommissioning: Driving cost efficiency through effective late-life stewardship, creating a platform for timely delivery;
- Commercial transformation: Improving market efficiency, establishing a competitive and sustainable market;
- Technology, processes and guidance: The development and deployment of technology, appropriate regulatory processes and clear guidance underpin delivery of the Strategy; and
- Supporting energy transition from late life into decommissioning.

The latter area is summarised as "Reducing greenhouse gas emissions from decommissioning and capitalising on opportunities to reuse or re-purpose infrastructure".

# Decommissioning – opportunities and challenges



## Circular Economy opportunities from decommissioning

OEUK's Decommissioning Insight 2021 report forecasts that over 1.2m tonnes of O&G structures from the North Sea region will be brought ashore over the next decade, much of which can be reused or recycled, reducing the emissions-intensive creation of alloys from raw materials. Dales Voe port in Shetland received delivery of the 14,200 tonne Ninian Northern platform in 2020, evidencing Scotland's potential within this circular economy.

Of particular relevance to energy transition, OEUK has noted that decommissioning in the form of the removal of assets is no longer the only path to follow when production ends. Its Decommissioning Strategy highlights that "in some cases re-purposing options are available which are supportive of either the transition to a net zero energy system, or reuse for other hydrocarbon-related purposes."

The reuse and repurposing of infrastructure is the best option to reduce waste and emissions generated by decommissioning activities. Given the significant cost of decommissioning, it may also be a more cost-effective, and potentially profitable, way for companies to deal with otherwise redundant assets.

As such, the NSTA is encouraging companies to ensure that reuse is considered before decommissioning and working collaboratively with government and industry to share reuse success stories from the UKCS and around the world.

Examples of good cooperation for mutual benefit exist. East of Shetland licensees are taking a collaborative approach to area decommissioning by aligning decommissioning activity in the East of Shetland Area Plan, and the concentration of ageing assets in the ScotNS means that similar initiatives should be achievable.

## Decommissioning challenges – complex revenue and cost drivers

O&G commodity market fluctuations and the competing priorities of infrastructure owners have made it difficult to establish and maintain a reliable decommissioning programme – as commodity prices increase, the continued use of facilities that were previously uneconomical when the oil price was lower becomes profitable again, pushing back decommissioning dates.

This volatility in turn makes it more challenging to achieve the efficiencies that would be generated through collaboration and economies of scale. Infrastructure owners and the supply chain cannot invest in opportunities when they have limited confidence in the programme of planned decommissioning.

The industry recognises this issue and is seeking to address it through the provision of better information. The data gathered through the UKCS Stewardship Survey and reported in the NSTA's annual UKCS Decommissioning Cost Estimate Report is intended to support decommissioning decision making by providing companies with better information and evidence and sharing examples of good practice, as is the NSTA's UKCS Decommissioning Benchmark Report.

## Synergies with, and competition from, offshore wind

The predictability of the decommissioning market also faces challenges from an increasing overlap between it and the offshore wind installation market. Both can make use of the same lift vessels and resources, especially for smaller platforms.

This could offer efficiency opportunities, with lift contractors able to fit more flexible decommissioning contracts in periods when windfarm installation demand is quieter, increasing utilisation and reducing operator costs; however, as the windfarms age and themselves need to be decommissioned, demand for lift vessels and resources will increase.

Further overlap will happen as wind turbines grow in size and the lift vessels required for them become the same as those needed to decommission the larger O&G installations in the CNS and NNS.

## Conclusion – the unpredictable value of assets and timing of decommissioning

Decommissioning and re-use offers an economic opportunity for Scotland, but the interaction of complex drivers of revenues and costs make the current economic value of North Sea assets volatile and hard to predict. An O&G asset's expected useful life and value is based on associated future cashflows, but unstable geopolitics means these are subject to significant swings as is clearly evidenced by the impact of the war in Ukraine on O&G prices.

### Key observation

Planning and progressing the reuse of existing O&G assets in a systematic way will be challenging because the volatility of commodity prices means the profitable life of an asset can extend without warning

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**Key observation**

Scotland has a strong track record in renewable energy, including offshore wind, wave and tidal technology, and it is at the forefront of developments in hydrogen and carbon capture, usage and storage (CCUS)

The ScotNS O&G industry represents a concentration of skills, expertise, capabilities, and experience of delivery in one of the world's harshest marine environments, which are transferrable to the development of a broader, more integrated offshore energy sector.

The innovation required to generate a net zero energy future is a transformational opportunity for the offshore O&G and renewable energy sectors. It offers opportunities to the whole supply chain, from small and medium sized companies to multinationals, and ports and communities in Scotland will benefit from investment and employment. The NSTA Energy Integration Project illustrates that integration of offshore energy systems could contribute to deliver around 30% of total carbon reduction requirements needed to meet the UK government's 2050 net zero target.

The Offshore Renewable Energy Catapult's Reimagining a Net Zero North Sea report provides an illustration of what could be achieved. It estimates that investment of up to £416bn is required over the next 30 years to create a transformational change to an energy system driven by floating offshore wind, scaled-up blue and green hydrogen with limited expansion of other marine renewables, and O&G electrification (as discussed in detail in Section 5). This would potentially contribute £125bn per year to the UK economy by 2050, supporting more than 230,000 jobs.

## North Sea Energy opportunities

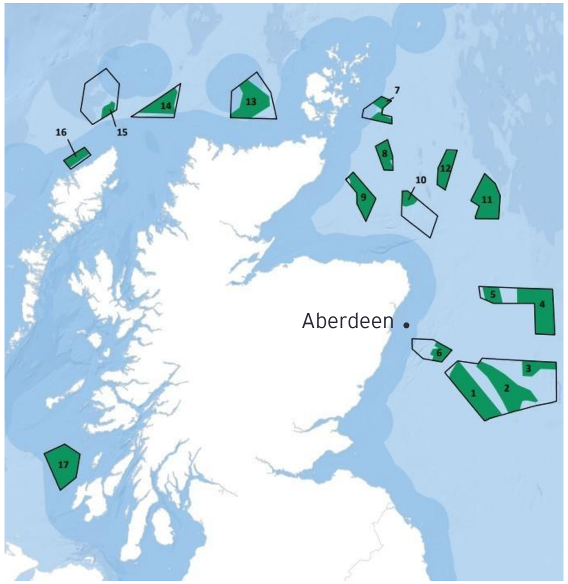
### Offshore Wind

Technological improvements have driven down the costs of fixed offshore wind to the extent that it has been price competitive with conventional power generation sources since 2017. Further advances and increases in efficiencies are expected to mean that the industry will continue to grow and be allocated large development areas in the North Sea. Ongoing maintenance and decommissioning requirements will draw on existing O&G supply chain capabilities.

The extent of Scotland's natural resources, both in terms of offshore waters and prevailing winds, represents a major opportunity to generate renewable electricity. The January 2022 announcement of the results of Crown Estate Scotland's ScotWind leasing round underlines the scale of the opportunity. 17 projects were successful and offered Lease Options Agreements. The successful projects have a total intended installed capacity of 25GW and their committed expenditure for Scotland amounts to £1bn per 1GW of capacity.

ScotWind is the world's largest commercial round for floating offshore wind with 11 of the 17 projects proposing floating turbine technology, putting Scotland at the forefront of floating wind. The 17 successful selected projects are close to existing North Sea O&G activity. Initial indications suggest a multi-billion pound supply chain investment in Scotland, with BP announcing that it will make Aberdeen its global operations and maintenance centre of excellence for offshore wind, creating up to 120 new direct jobs.

**ScotWind leasing round – map of option areas, successful projects shown in green**




Source: Crown Estate Scotland; [scotwind-map-of-option-areas-170122 (crownestatescotland.com)]

# ScotNS as an integrated energy basin (cont'd)



## Offshore electrification

O&G will remain an important part of the integrated energy basin for years to come, but the industry recognises that it needs to reduce its GHG emissions. Amongst other measures, the OEUK's NSTD sets out plans for the industry to reduce emissions through supporting platform electrification.

As noted in Section 5, offshore O&G production is currently entirely powered by thermal generation on platforms. Data from the Environmental Emissions Monitoring System (EEMS) database for 2018 indicated that Power GHG emissions from O&G platforms account for 68% of offshore emissions. Linking offshore facilities to the onshore electricity network offers a solution. Furthermore, the supply of energy to O&G platforms could represent a commercial opportunity for renewable power developers, as investment in infrastructure and leveraging of O&G deep water technologies could support growth of that sector. Crown Estate Scotland is facilitating this with its INTOG leasing round to support offshore electrification.

In its UKCS Energy Integration report, the NSTA identified seven platforms as notional brownfield electrification projects that could be feasible due to distance from shore (230km), and each other (60km) respectively in the North Sea. The main economic drivers of these projects are electricity prices and platform modification costs. The report concluded that achieving a breakeven position would only be possible with technology-driven capex efficiencies on platform modifications and power transmission equipment. Potential efficiencies are offered by hybrid schemes such as partial electrification of platforms where generation capacity already exists to provide power continuity and optimise the link to shore. Costs could also be driven down by joint projects sharing infrastructure, sharing connection to onshore power networks in both the UK and Norway, and by platforms sourcing power directly from offshore windfarms.

For comparison and as discussed in section 5, Norway's electrified platforms (and less carbon intensive onshore generation) contribute to a lower carbon intensity figure of 5.6 $gCO_2eq/MJ$, compared to the UK's 7.9 $gCO_2eq/MJ$.

The NSTD estimates that a £15bn investment is required in offshore transmission infrastructure to connect an additional 30GW of offshore wind between now and 2030, and that to deliver 50% of the emissions reduction target by 2030, £2bn-£3bn of investment is required to allow completion of at least one or two of the currently identified electrification projects.

However, the commercial decision to electrify assets will be impacted by a range of factors, including:

- The future life of the assets – some brownfield platforms have short remaining lifetimes and would not be commercially viable to decarbonise.
- Floating platforms may not be able to bear the weight of infrastructure needed for a power connection.
- The impact of declining industry wide production and estimates of future activity.
- The cost of mechanisms for delivering power.
- The need to meet upfront infrastructure costs and the ability to work with offshore wind providers to share these costs.

That said, some progress towards electrification is being made, despite the required investment and current challenging economic factors. The NSTA issued grants for North Sea electrification studies in December 2021, with three companies being awarded equal shares of £1m to advance the widespread electrification of offshore installations on the UK continental shelf.

# ScotNS as an integrated energy basin (cont'd)

## Hydrogen

Scotland is at the forefront of the development of the hydrogen industry. In 2021 SG published its Draft Hydrogen Action Plan, setting an ambition of 5GW installed hydrogen production capacity by 2030 and 25GW by 2045. Hydrogen industry centres have considerable geographical overlap with the O&G industry – Aberdeen City Council plans to make the city a Hydrogen Hub over the next decade, while the Acorn Project will produce blue hydrogen from natural gas at St Fergus, and Orkney has become a demonstration hub for the hydrogen economy through projects such as Surf 'n' Turf, BIG HIT, HyDIME and HyFlyer.

## Carbon Capture and Storage

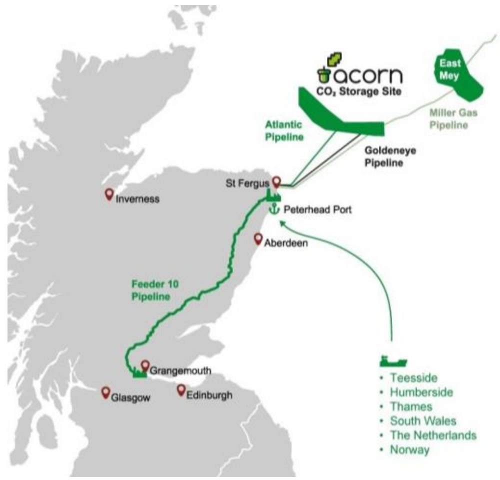
The Committee on Climate Change (CCC) has consistently stated that the development of UK-based CCUS technology will be essential in achieving targets for reducing greenhouse gas emissions across the economy. CCUS, the process of capturing $CO_2$ emissions or removing $CO_2$ from the air, and either using it or transporting it to storage locations for permanent sequestration, is necessary for the decarbonisation of O&G and blue hydrogen and to enable the transition to a net zero North Sea. The process would act as a carbon sink for hydrocarbon production and for industrial processes. With depleted O&G fields being repurposed as storage reservoirs, it would also enable the ScotNS to become a key European location for the sequestration of carbon.

The Acorn Project is one of the UK's more advanced CCUS projects. It is based at the St Fergus gas terminal in Aberdeenshire in order to make the best use of legacy O&G infrastructure and appropriate geology for $CO_2$ storage. It plans to capture $CO_2$ from the St Fergus processing units and from blue hydrogen production, and proposes to repurpose the existing Goldeneye gas pipelines to take $CO_2$ to its storage site under the seabed in the East Mey formation, 100km offshore. Ultimately, the aim is to scale up to import $CO_2$ via ships docking at Peterhead Port and from the Central Belt via re-purposed pipelines.

Although Acorn was unsuccessful in its application to BEIS to be in the first wave ("Track-1") of clusters to be deployed in the mid-2020s, it was recently awarded £80m of SG support from its Emerging Energy Technologies Fund to accelerate its development.

## Acorn Project

Source: Project Acorn; https://theacornproject.uk/about/

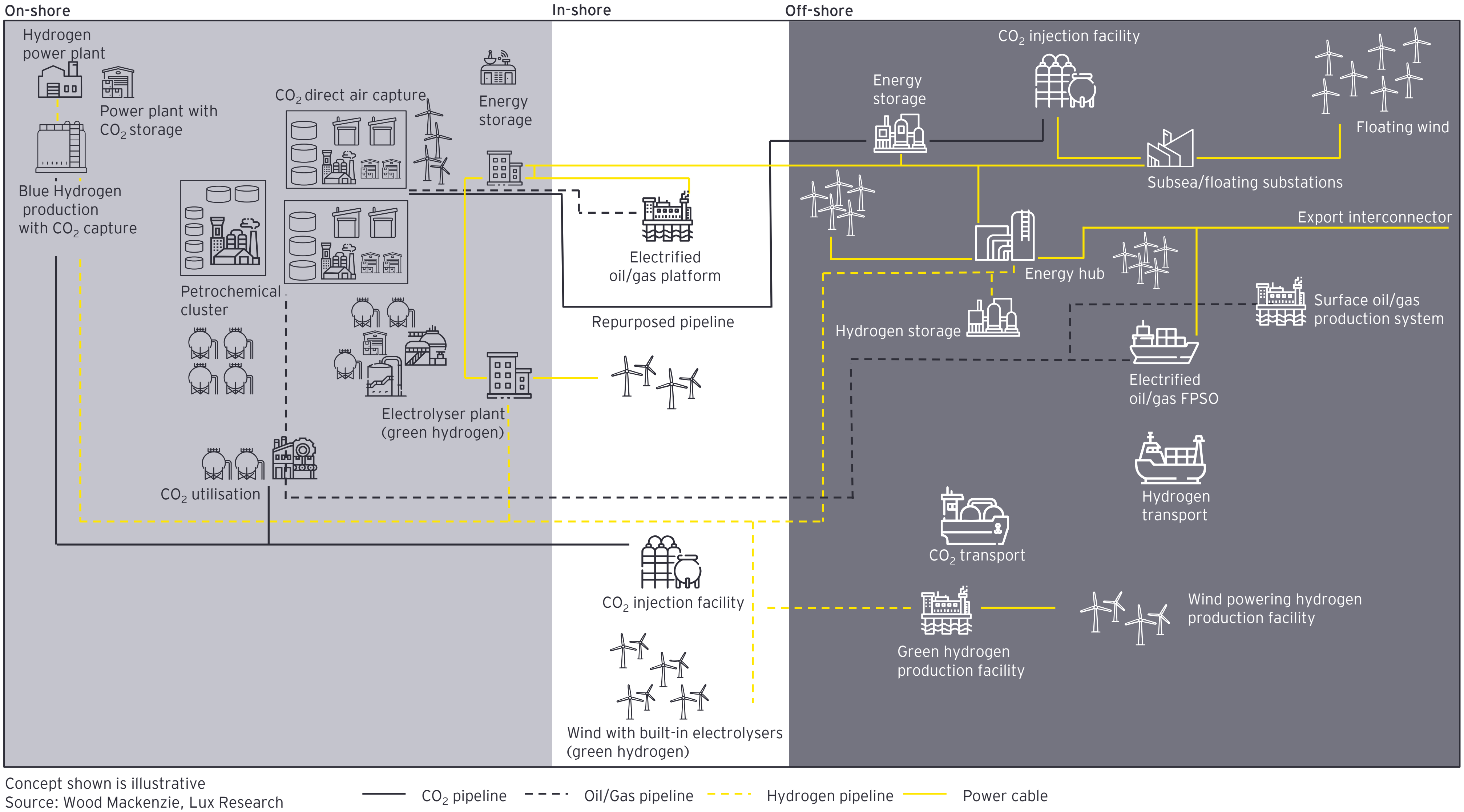



## Potential combinations of these technologies in the North Sea

The technologies described above are all relatively new, but there is both a commercial and an environmental imperative that they are accelerated to deliver the energy transition. Research institutes across Europe, including NZTC, TNO and SINTEF, have active projects investigating how the technologies can be combined, such as using offshore wind energy in the electrification of platforms; repurposing platforms for hydrogen production from offshore wind parks, allowing energy to be transferred as hydrogen via pipelines; and gas to wire, using the existing offshore grid to transmit electricity generated from gas (with application of CCUS to ensure zero emissions) at platforms to shore.

The conceptual diagram on the following page illustrates the potential North Sea energy basin ecosystem. It will take time and significant investment to develop to the extent shown, but initiatives such as Orkney hydrogen hub are demonstrating system integration, while the Acorn Project and INTOG are working to put the building blocks in place. At-scale green energy is the end goal, but blue hydrogen from natural gas represents an important intermediate solution to help the transition to net zero, building a hydrogen economy and creating demand. Scotland is well-placed to grow these areas due to its abundance of renewable energy, existing natural gas sources, and supply chain expertise.

# The ScotNS has potential to become an integrated energy basin ecosystem (visualised below), with renewables, hydrogen, O&G and CCUS linked to produce net zero energy




Concept shown is illustrative
Source: Wood Mackenzie, Lux Research

# Potential re-use of O&G assets



## Potential benefits of asset re-use

There are a number of potential benefits to re-using O&G infrastructure to support emerging energy transition sectors:

- The costs of decommissioning existing O&G infrastructure are high, with recent estimates putting the total cost of decommissioning UKCS offshore O&G infrastructure at £46bn. Although the industry is driving efficiencies in the process – the NSTA's UKCS Decommissioning Cost Estimate 2021 report highlighted that over the four year period of 2017-2020 cost reductions in the range of 25-35% were achieved across the well decommissioning, removals and subsea infrastructure – decommissioning remains a major liability for the industry. Being able to re-purpose and re-use some of these assets in support of the energy transition would restore value to the infrastructure and further reduce this liability for the industry.
- There may also be benefits for the developers of the new energy infrastructure if the cost of re-purposing existing assets is less than the cost of installing new infrastructure. This will lead to a lower cost for developers and enable existing operators of infrastructure to extract further economic benefit from assets or reduce decommissioning liabilities.
- Re-purposing infrastructure can also enable the accelerated rollout of emerging industries. This can be seen with both the Acorn and HyNet CCUS projects which plan to re-use infrastructure to improve on the delivery timetable. Re-using infrastructure also aligns with the idea of a circular economy and reduces the need to direct resources towards the development of new infrastructure, potentially lowering the carbon footprint of infrastructure.
- As the ScotNS is a mature basin, the opportunity to re-purpose its assets is occurring sooner than is the case for younger hydrocarbon basins. This means that successfully identifying ways of re-using infrastructure could support Scotland in becoming a world leader in emerging sectors such as CCUS and hydrogen.

That said, some caution is necessary in relation to the scale of the opportunity. To date, detailed identification and due diligence on the usefulness of existing assets has not been carried out by the industry or UKG and SG. Some projects, such as Project Acorn, have considered specific assets, and BEIS has identified an initial list of existing pipelines that could be reused for CCUS. Desktop studies such as the Vysus Group's report for SOWEC on the re-purposing of assets for hydrogen generation have identified particular fields, in this case Brent in the NNS and Markham in the CNS, as strong candidates for re-purposing. However, they do not represent a complete picture of the North Sea infrastructure as a whole.

To produce that picture would require extensive analysis as the specific circumstances of each piece of infrastructure will determine its suitability for re-use. This is considered further below:

## Factors affecting re-use of assets

1. **Location:** To be useful, the assets need to be located in an area well suited to support emerging industries: for example, proximity to areas of offshore windfarm development; CCUS infrastructure should be located close to $CO_2$ storage locations.
2. **Size:** The size of infrastructure needs to be suitable and appropriate for the proposed use, in particular the capacity of pipelines and potential reservoirs need to be sufficient to justify the investment in their re-use.
3. **Age and Asset Condition:** Assets need to be in an appropriate condition for re-use. This is important for safety, operational performance, and longevity of infrastructure. Some assets, such as platforms, deteriorate quickly after cessation of production, which limits their re-use potential. Aged assets are likely to have degraded to a greater extent and therefore may not be suitable for re-use, or older assets might have a shorter remaining life meaning that the re-use asset lifespan may be not be long enough to be economical.

# Potential re-use of O&G assets (cont'd)



## Factors affecting re-use (cont'd)

4. **Suitability of assets for re-use:** Both $CO_2$ and hydrogen have different physical properties to oil and natural gas. $CO_2$ can produce corrosive acids when mixed with water, while hydrogen can cause embrittlement in some metals. This may mean some infrastructure is not suitable for re-use. In particular, factors such as how much pressure infrastructure can withstand, the materials used, and their ability to withstand corrosion will be important.
5. **Availability of data:** Any re-use will require an extensive understanding of assets to ensure safety concerns and assets performance are well understood. Where data does not exist or it is insufficient to justify re-use potential, this may act as a barrier to re-using infrastructure.
6. **Cost differentials:** Whilst the cost differential between re-using existing infrastructure and installing a new asset may not be the only benefit, it will be an important consideration when deciding whether to re-use assets. The industry is at an early stage in the process of re-purposing and re-using its infrastructure and there is an ongoing need to further refine its cost models, consistent with advances in its understanding of safety and technical risk management to help drive these costs down, thereby making this approach more attractive. Trade-offs in terms of capex vs. opex, whole life costs, and incentive regimes will further complicate considerations.
7. **Connections to other active infrastructure:** The decommissioning or re-purposing of particular pipeline assets is complex due to the wider implications for other parties. North Sea assets are often connected to assets owned by other parties and relied on by them for economic production. It may not be possible to repurpose assets that continue to be relied upon by others.
8. **Timing of decommissioning/availability:** The re-use of assets for emerging sectors requires assets to no longer be used in O&G production. There will be costs associated with preserving assets for future re-use, which are likely to increase if there is a longer period between the cessation of production and re-use. As such, coordination of the timing of their transition from one use to another will be crucial. Ideally the timing mismatch should be minimised and the policy framework should support the commercial incentives for current operators to facilitate re-use of assets when it is advantageous to do so.
9. **Complexities of ownership:** As highlighted in the discussion of pipeline ownership, the complexities of different ownership of assets and overlapping rights of use, will make re-purposing assets challenging due to the wider implications for other parties. Moves towards re-using existing assets in an integrated energy basin will require a high level of coordination and cooperation between government, operators and contractors, but competing rights and interests will cause friction, even where there might be an economic case for re-use.
10. **An understanding of liabilities associated with the assets:** There may be wider commercial risks such as liabilities associated with the existing assets. The embedded risks in a platform or pipeline could prove difficult to establish with certainty, so, unless there is clear absolution of liability when the infrastructure is passed to its future user, companies may decide that the potential for future liabilities is too a high a risk and choose to continue with full decommissioning and removal. Mechanisms for the transfer of liability need to explored, and could present complications where the infrastructure in questions is one part of an ecosystem of assets.

# Potential re-use of O&G assets (cont'd)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## Potential re-use of existing assets

There is considerable uncertainty as to the possible extent of re-use, dependent as it is on the large number of factors explored on previous pages, such as asset condition, location, the speed of growth of new industries and processes, legislation, regulation and carbon pricing. In the table below, we have considered potential re-use approaches identified for various North Sea asset types, providing commentary on the associated physical constraints and risks, and assigned a RAG rating to reflect the ability to reuse.

| Asset type | Potential re-use | Comments, constraints and risks | Conclusion and RAG |
|---|---|---|---|
| Reservoirs | Depleted O&G reservoirs have been identified as key resources for the geological storage of $CO_2$ or inter-seasonal hydrogen storage. Although not a man made asset, they are an important potential re-use asset. | Leakage through geological features and fissures has been identified as a risk for subsurface reservoir $CO_2$ storage. In the North Sea basin this risk has been mitigate by the O&G industry having amassed a detailed knowledge of the sub-sea geology of the North Sea. Studies using this knowledge have indicated that permanent sequestration of $CO_2$ in the subsurface is technically feasible and geologically safe, while Equinor claims two decades of experience with storing $CO_2$ in offshore locations in Sleipner and Snøhvit to avoid venting into the atmosphere. The HyNet project also plans to store $CO_2$ in depleted gas reservoirs under the seabed of Liverpool Bay in the Irish Sea.<br><br>The Acorn Project CCUS plans to use the abandoned Goldeneye reservoir as its Phase 1 storage site. It estimates the storage capacity of the first storage location to be 30Mt, the complete Acorn $CO_2$ licence to be 150Mt, and known offshore storage locations within 50km of St Fergus pipeline corridor to be 23.8Gt.<br><br>The University of Edinburgh's HyStorPor project is currently undertaking analysis to determine whether sub-sea reservoirs could also be used for hydrogen storage. | Considerable analysis has been performed in relation to the re-use of depleted hydrocarbon reservoirs and, whilst some technical challenges remain, this appears to be viable.<br><br>G |
| Onshore terminals | Onshore terminals would need to be adapted to facilitate the needs of the hydrogen and CCUS industries. | The Acorn Project plans to develop St Fergus gas terminal, with the terminal becoming a transport node and storage facility for $CO_2$ before it is transferred to subsea storage sites. It would also be the site for the Acorn Hydrogen plant, which would generate hydrogen from natural gas while capturing and storing the $CO_2$ emissions. | As existing onsite processes are expected to continue, re-use potential is likely to be limited to land and some buildings. However, the presence of existing industrial activities means that these locations are well-suited to these new developments.<br><br>G |

**RAG key:** R Unlikely to be viable A Potentially viable G Appears to be viable

# Potential re-use of O&G assets (cont'd)



| Asset type | Potential re-use | Comments, constraints and risks | Conclusion and RAG |
|---|---|---|---|
| Pipelines | Pipelines that are no longer needed for hydrocarbon extraction could be re-purposed for the disposal of $CO_2$ to subsea storage reservoirs, or for the import of hydrogen from offshore production locations or transfer to subsea storage.<br><br>Six onshore hydrocarbon pipelines begin at St Fergus, heading south to the Central Belt. Of these pipelines, the Feeder 10 pipeline, running from the Forth Estuary to St Fergus, could in principle be reused for CCUS and $CO_2$ transport, connecting significant industrial centres, including Grangemouth, to $CO_2$ storage facilities. | Dependent on the condition and location of trunk pipelines, re-using these pipelines to transport $CO_2$ could bring considerable advantages, bringing significant cost and time savings. Proximity to a geological storage reservoir is essential, and Project Acorn has identified the Goldeneye, Atlantic, Cromarty and Miller pipelines as having good potential for reuse for $CO_2$.<br><br>In relation to onshore pipelines, the 2014 Element Energy Front End Engineer Design (FEED) study commissioned by Scottish Enterprise validated Feeder 10 for capacity of up to 2.5Mt/yr transport of $CO_2$ from Avonbridge to St Fergus. The study noted that with modest capital cost of £77m, the existing pipeline should be capable of supporting up to 7 $MtCO_2$/yr. This would provide an essential link from some of Scotland's most $CO_2$ intensive industries to permanent $CO_2$ sequestration sites.<br><br>There are some uncertainties associated with the suitability of redundant pipelines. Pipelines designed for hydrocarbon transport were not intended for $CO_2$ or hydrogen use, and there is a risk that they are not suitable given their different physical and chemical properties.<br><br>The timeframe for re-use would also take most pipelines beyond their initial design life, and there is a risk that they are corroded or lack integrity. There may also be risks associated with legal and permitting requirements and liability arrangements.<br><br>However, technical studies have indicated that re-use should be feasible, and both Project Acorn and HyNet plan to re-use existing pipelines for transporting $CO_2$ . | Trunk pipelines are considered to have the greatest re-use potential, and the operational monitoring and maintenance costs are expected to be relatively low compared to the cost of building and installing a new pipeline.<br><br>Further analysis and asset integrity checks will be required before re-use can be considered with certainty. However, the IOGP's October 2021 Re-Stream study identified no specific technical issues that would of themselves prevent the transportation of gaseous phase $CO_2$ in existing O&G pipelines.<br><br>Project Acorn is currently carrying out Front-End Engineering and Design (FEED) studies for the offshore pipeline system and its inspection.<br><br>G |

# Potential re-use of O&G assets (cont'd)

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| Asset type | Potential re-use | Comments, constraints and risks | Conclusion and RAG |
|---|---|---|---|
| Platforms and FPSOs | O&G platforms and FPSOs could be converted to offshore electrolysis platforms to generate hydrogen with little electrical cable power loss due to proximity. Platforms could also be used to house control systems for $CO_2$ injection wells.<br><br>There is potential to reuse accommodation platforms for staff deployed in the development and maintenance of offshore windfarms. | There may be an advantage to re-using platforms as part of the transport and storage infrastructure for CCUS, and it is understood that this is undergoing active consideration in a number of locations – for example, HyNet plans to re-use current offshore platforms facilitate $CO_2$ storage in Liverpool Bay. The relative flexibility offered by floating platforms and FPSOs reduces the risk that they are not in the optimum location for re-use. We also recognise that FPSOs may be utilised in other countries before being re-used in Scotland.<br><br>The existing facilities would require extensive adaptation. Complex O&G production facilities may require significant and potentially expensive modifications to be adapted to $CO_2$ injection. Legacy systems will need to be removed and new $CO_2$ processing and injection facilities installed. The physical state of the platform's legs (known as the jacket) will also need to be reviewed to confirm its structural integrity and the adequacy of the platform size.<br><br>Regulatory uncertainties, related to the granting of new permits and the question of liabilities from previous asset owners if the ownership of the platform changes at the same time as the move from O&G production to $CO_2$ sequestration, may also lead to additional costs.<br><br>Vysus Group's desktop study for SOWEC on the re-purposing of assets for hydrogen generation considered the conversion of existing offshore platforms to electrolysis platforms to generate hydrogen offshore. However, it notes that this would require sufficient space and weight, the provision of which may render the operation uneconomic. The additional cost of offshore production could well outweigh the savings generated by avoiding power loss from offshore windfarm to onshore hydrolysis plants. | Re-use of these assets is only likely in very specific circumstances.<br><br>Ultimately, it can be expected that a re-used platform will have lower upfront capital costs but higher ongoing annual operating costs than a new purpose-built platform. Operators will need to assess the whole life economic balance of these factors to determine whether re-use of existing facilities is more cost effective than a new platform.<br><br>Offshore production of hydrogen could be expected to import potentially considerable cost and risk to a new sector. As such, it seems unlikely to be a significant re-use opportunity in the short to medium term.<br><br>A |

# Potential re-use of O&G assets (cont'd)

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| Asset type | Potential re-use | Comments, constraints and risks | Conclusion and RAG |
|---|---|---|---|
| Subsea production systems | The subsea production system, including protective structures, manifolds, towheads, processing systems, and associated pipeline, link into the reservoirs and could be re-purposed to inject $CO_2$ or hydrogen into reservoirs. | Re-use of existing subsea systems may not be economically viable, given the specific location and design requirements of $CO_2$ or hydrogen storage.<br><br>Rather than re-using existing assets, Project Acorn plans to install new subsea infrastructure, including a pipeline end manifold, connecting spools, other subsea equipment and a power, control and communications umbilical for the well. Similarly, the Norwegian Northern Lights project plans to build new facilities at its injection site. | Location, condition and design factors associated with existing subsea production systems mean that their re-use for $CO_2$ or hydrogen appears unlikely.<br><br>R |
| Wells | Existing wells could be re-used to inject $CO_2$, or hydrogen, into the depleted reservoir. | For wells to be re-used, they would need to be situated in the correct location in the field. The optimal position for injecting $CO_2$ or hydrogen into reservoirs is unlikely to be the same as those originally selected for extraction.<br><br>Given their expected useful life may be exceeded, the condition of existing wells would also be of concern, bringing risks around corrosion. They may not meet safety standards for alternate use. The design of an oil or gas production well will also be different from that of a $CO_2$ injection well.<br><br>Acorn does not plan to re-use wells in Goldeneye as they have been plugged and abandoned. | Using a new, purpose built well would de-risk this element of the infrastructure, ensuring that its location, condition, design and metallurgy is fit for purpose. New wells are most likely to be required for CCUS as a consequence of the technical difficulties, risks and economic realities.<br><br>As such, re-use of hydrocarbon wells seems unlikely.<br><br>R |

**Key observation**

O&G infrastructure in the ScotNS can facilitate the transition to an integrated energy basin. Several asset types appear to be viable or potentially viable for re-use, including Reservoirs, some Platforms and FPSO units, Pipelines and Onshore Terminal sites

# ScotNS transport infrastructure



In addition to the specific asset categories discussed above, the transport infrastructure developed for the O&G industry is well-suited to adapt to the services of the decommissioning and renewables industries.

## Port Infrastructure

The Scottish Energy Ports Capability Directory lists 32 Scottish ports which offer a range of infrastructure, facilities, skills and supply chain to support the O&G, decommissioning and renewables industries.

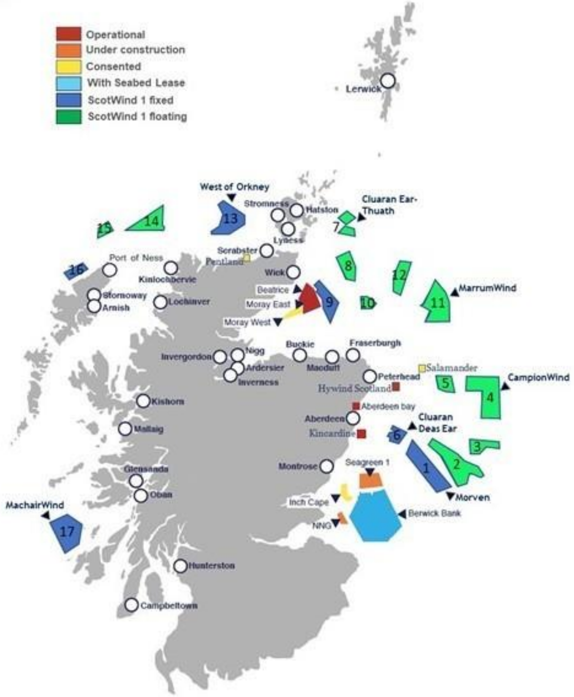
The ports range in size and depth and have a varying involvement in the Scottish O&G sector. The major ports for the export of crude oil are Sullom Voe, the ports on the Forth and Orkney. The ports on the Forth also export liquefied gas. Several ports also have suitable infrastructure to enable O&G mobilisation and demobilisation work (e.g., Leith), the construction and maintenance of subsea topside structures (e.g., Dundee) and deeper waters that allow the servicing of decommissioning and subsea projects (e.g., Lerwick).

In recent years focus has increased on how existing port infrastructure can be adapted to support the circular economy and renewable energy sector. An example of the significant investment in port infrastructure to facilitate decommissioning is the approval of funding towards the Dales Voe Ultra Deep water port in Lerwick. This will enable the direct offload of semi-submersible crane vessels, further enhancing Scotland’s competitiveness against other ports overseas.

Investment in Scottish ports is enhancing their utility for the renewable energy sector. A £40m private investment will see the creation of a riverside marine berth capable of accommodating the world’s largest offshore wind installation vessels at the Port of Leith, whilst a £110m offshore wind tower factory has been proposed for the Port of Nigg on the Cromarty Firth. The proximity of Scottish ports and harbours to the 17 offshore wind offshore project sites of the initial ScotWind round is shown on the map below.

A number of ports offer the spare capacity and physical space that the renewables industry need. Ardersier Port on the Cromarty Forth has roughly 340 acres of laydown area available, in addition to more than 1km of quayside. Peterhead Harbour’s expansion has added 32,000m2 of laydown area, and the planned redevelopment of Hunterston Port adds a further 25 hectares of laydown area, all of which could be used for fabrication and assembly to aid future offshore wind projects.

### Scottish ports and offshore wind




Source: Offshore Wind Scotland

## Aviation

Another legacy of the North Sea O&G industry is that Scotland’s aviation infrastructure is well-positioned to support the development of renewables like the ScotWind Leasing Round 1 windfarms and Project Acorn’s CCUS ambitions. Through its support of the offshore industry, Aberdeen airport has grown to become one of the world's busiest commercial heliports, with four operators serving more than 440,000 helicopter passenger journeys in 2019.

# Infrastructure conclusion



## Conclusion

As a mature hydrocarbon basin, the ScotNS contains a lot of existing offshore O&G infrastructure. Owners of this infrastructure have obligations to decommission assets at the end of their economic lives, representing a significant liability for the O&G industry.

However, the North Sea's O&G infrastructure also represents an opportunity in the transition to an integrated energy basin. Some O&G installations could be re-purposed to facilitate renewable power generation and the net zero economy, through offshore wind, hydrogen production, and CCUS, thereby transforming O&G liabilities into assets in the energy transition. This would also have the benefit of reducing waste and emissions generated by decommissioning activities.

It is likely that only a proportion of existing assets will be suitable for re-purposing – factors such as the importance of location, size, age and condition of the assets in question will dictate that. Challenges will also need to be addressed around complexities of ownership and liabilities associated with the assets, and the difficulty in establishing and maintaining a reliable decommissioning programme due to commodity market fluctuations. The extent to which this is possible will depend on whole life costs considerations and legal complexities around permits, liabilities, etc. which will require a high level of coordination and cooperation between government, operators and contractors.

These are not insurmountable issues – commercial complexity is O&G operators' business as usual. Many are themselves transitioning from O&G to low carbon businesses, they know and understand their existing facilities and can see the economic opportunities of the change. They also have extensive survey, planning and seabed data density of the geology around their reservoirs and platforms, meaning they can mitigate risks associated with development.

## Key observations

The elements of the O&G industry that offer the best opportunities for redeployment in an integrated energy basin are:

- Depleted reservoirs for CCUS and potentially hydrogen storage
- Platforms as part of the transport and storage infrastructure for CCUS or, in the medium- to long-term, electrolysis platforms to generate hydrogen offshore
- Pipelines, both onshore and offshore, for transporting $CO_2$ for storage
- On-shore terminals, as well-located industrial sites for growing energy sectors

The growing offshore sectors can also draw on the Scottish O&G industry's world class supply chain concentration of skills, expertise, capabilities, and experience of delivery in one of the world's harshest marine environments, backed with the country's extensive ports and aviation infrastructure. These areas of the industry are themselves evolving to support these developing sectors.

The re-purposing of existing North Sea infrastructure could enable the accelerated rollout of emerging industries. As a mature basin, the chance to re-purpose its assets is occurring sooner than in younger hydrocarbon basins, meaning that successful re-use could secure Scotland world leader status in emerging sectors such as CCUS and hydrogen.

# 7 The O&G Energy System

# Energy System Glossary of terms

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| Term | Definition |
|---|---|
| **Primary energy** | ► Imports and Scottish production, i.e., the inflows to the system on the Sankey Diagram |
| **End use** | ► Exports and Scottish consumption, i.e., the outflows from the system on the Sankey Diagram |
| **Scottish production** | ► O&G products made or extracted in Scotland. In the case of downstream oil and oil products this includes any products processed in Scottish facilities, even if the raw material used in production has been imported. |
| **Imports** | ► O&G products entering the Scottish energy system from either rUK or ROW, rather than being produced domestically |
| **Exports** | ► O&G products leaving the Scottish energy system to either rUK or ROW, rather than being consumed domestically |
| **Scottish consumption** | ► O&G products consumed in Scotland |
| **rUK** | ► Rest of the UK |
| **ROW** | ► Rest of the world |
| **Upstream** | ► Relating to the process by which raw O&G products are extracted from the ground |
| **Downstream** | ► Anything related to the processing of those products coming out of the upstream process to make them into usable products and distribute to consumers |
| **Primary oil products** | ► In this case, primary refers to the fact these oil products have yet to be processed into usable products, i.e., the products coming out of the upstream process. This includes crude oils, NGLs and feedstocks. Further detail on these products can be found on the following page |
| **Oil and oil products** | ► Refers to products coming out of the downstream process, i.e., post-refining or post-processing at a petrochemical facility |
| **Natural gas** | ► Natural gas piped around the UK via the National Grid |
| **Crude oil** | ► A naturally occurring, unrefined mixture of hydrocarbons and other organic material that exists in liquid phase in natural underground reservoirs |
| **NGLs** | ► Natural gas liquids (NGLs) are hydrocarbons in the same family of molecules as natural gas and crude oil, composed exclusively of carbon and hydrogen. Ethane, propane, butane, isobutane, and pentane are all examples of NGLs |
| **Feedstocks** | ► Any unprocessed material used to supply a manufacturing process. In this section we are specifically referring to the backflows from petrochemical plants |

# Introduction to the O&G System


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## Introduction to the O&G System

Despite the recent growth in renewables, 78% of Scotland's total energy consumption comes from O&G. As well as Scotland's reliance on O&G for domestic consumption, Scotland is a net exporter of various O&G products to the rest of the UK (rUK) and the rest of the world (ROW).

The following sections discuss in detail how O&G products flow to and from the Scottish Energy System, as summarised in the Sankey diagram on the following page. There are two sources of O&G "primary energy" - Scottish production and imports, with end use split into three categories: exports, domestic consumption, and "other" transfers and losses.

### O&G Products

The following sections will refer to various products within the Scottish O&G system, which have been categorised as follows:

- **Primary oil products –** Primary refers to the fact these oil products have yet to be processed. Consists of **Crude oil –** raw crude oil coming from the upstream extraction process, **NGLs –** Natural Gas Liquids (NGLs) are also an output of the upstream extraction process. NGLs includes ethane, propane, butane and condensate. Ethane derived from US shale gas is also considered an NGL (as opposed to a natural gas) because it contains a higher proportion of NGLs as well as the primary component methane, and is imported to Scotland in a liquefied state; and **Feedstocks –** the backflows from petrochemical plants.
- **Oil and Oil products** – refers to downstream petroleum products, i.e. post-refining. This includes naptha, aviation fuel, petrol, diesel engine road vehicle (DERV) fuel, white spirit, marine diesel oil, lubricants, and other fuel oils and miscellaneous products, as well as fractionated NGLs such as ethane, propane and butane.
- **Natural gas** – piped natural gas, including colliery (or coal bed) methane.

## Key trends over time

### Primary energy (inflows)

- O&G accounts for 93% of Scotland's total primary energy (all Scottish production and imports). The rest comes from renewables, primarily in the electricity sector.
- Scottish production of O&G products has reduced significantly over the last 20 years as North Sea fields have depleted and investment in new exploration has dropped. Despite this, production remains a significantly larger source of all O&G products than imports. Imported crude oil makes up only 10% of total crude sources, while 29% of Scotland's total natural gas supply is imported.

### End Use (outflows)

- Although they have trended downwards over the last 20 years in line with reducing production, exports are still the largest outflow from the Scottish O&G sector, accounting for 73% of the total end use for 2019. In other words, 73% of total sources of energy to the system (Scottish production plus imports) are subsequently exported. Scotland's largest export is crude oil, accounting for 62% of total exports. Scotland's status as a net exporter is a key distinction between the Scottish and UK Energy sectors.
- Domestic consumption makes up only 25% of total end use.
- "Other" transfers and losses refer to the small portion of ScotNS O&G production that does not leave the system as either an export or by being consumed domestically. They consist of transfers within the O&G system (NGLs being reclassified as they move between downstream and upstream processes), Stock change, i.e., the small portion of oil products which are held in storage, e.g.. for use in emergencies, and marine bunkers. i.e., the fuel for ships carrying exports, which are not technically counted as an export, but are also not consumed domestically on Scottish shores.

**The Sankey Diagram – How O&G flows around Scotland**

The Sankey diagram overleaf shows a snapshot of Scotland's O&G flows in 2019. The width of the bars are proportional to the relative volume and clearly illustrate Scotland's position as a net exporter, as well as the scale of ScotNS production compared to Scottish consumption levels.

# Scotland's O&G flows (2019)

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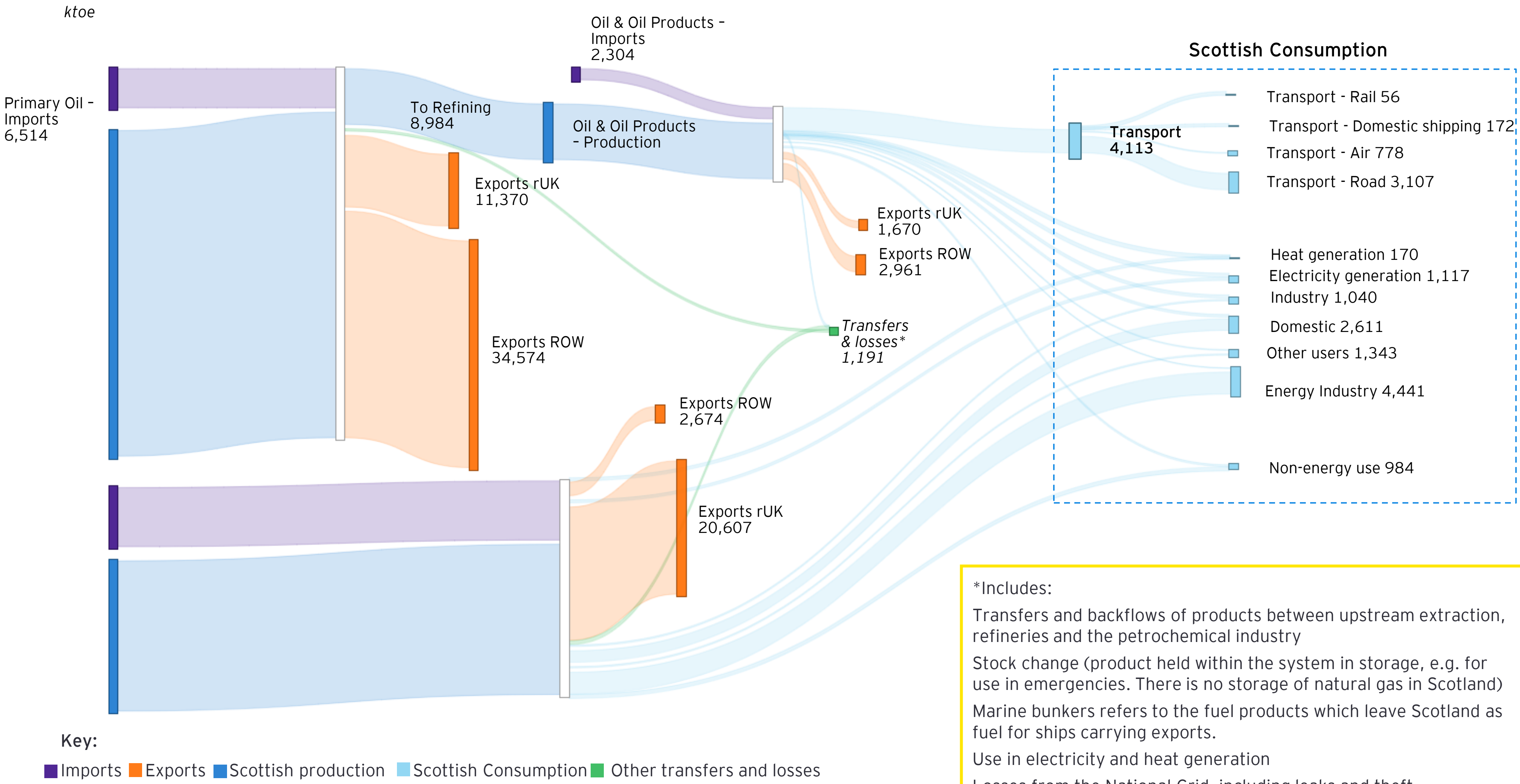


*Includes:

Transfers and backflows of products between upstream extraction, refineries and the petrochemical industry

Stock change (product held within the system in storage, e.g. for use in emergencies. There is no storage of natural gas in Scotland)

Marine bunkers refers to the fuel products which leave Scotland as fuel for ships carrying exports.

Use in electricity and heat generation

Losses from the National Grid, including leaks and theft

*Source: SG - Physical commodity balances of oil, gas and petroleum products*
*Digest of UK Energy Statistics (DUKES) 2021 - GOV.UK (www.gov.uk) (commodity balances)*

# 8 Upstream Primary Oil Products – Crude Oil

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# Crude Oil
# Key trends in Crude Oil flows

At first glance, it may appear counterintuitive for Scotland to import any crude oil when North Sea production far exceeds domestic demand, putting Scotland in a net export position. This nuance is important as it is very different from the UK position as a net importer. The key factors and trends in Scotland's crude oil flows are discussed in detail below.

### Nature of the global oil market

Crude oil is a traded commodity on the global oil market, bought by refineries seeking to make the highest possible margin on each barrel of end product and by commodity trading houses and investment banks who buy and sell crude based on trading viewpoints.

Different types of crude oil require different levels of refining, with sweet, light crudes being easier to process than heavy, sour crudes. Sweeter crudes, like the majority of those coming from the ScotNS, tend to be considered higher quality and therefore are more expensive to buy. Each refinery has an optimal mix of source crude oil which is determined by the processing capability of the refinery, the product mix that they wish to create for the market they serve, and the trade off between quality and price of the source crude oil. Scotland has historically always imported some crude oil cargoes because it is more economically advantageous for the refinery to use those crudes to satisfy domestic demand.

Each decision to import or export a quantity of crude is taken separately and by a wide range of stakeholders — those selling crude oil onto the global market in different parts of the world, those shipping crude oil and setting shipping prices, those buying crude oil for refining, as well as those trading (e.g. futures contracts).

Much like any other open market, oil prices change daily and so a refinery's optimal mix of source crude oil varies. This explains why Scotland's imports have ranged from 1,761ktoe to 7,424ktoe over the last 20 years, and also why Scotland has not consistently imported from the same countries over time.

The global oil market is a dynamic and complex one, and the economic factors currently driving imports of crude oil are out of policy makers' control and unlikely to be influenced by Scottish level policy changes.

### Changes to Refining Capacity

Although petrochemical operations have been expanding, the crude oil refinery at Grangemouth, like the rest of the UK refining industry, suffered from a decrease in demand for fuels during the COVID-19 pandemic. We discuss the downstream refining process in more detail in Section 11, but as the petrochemical and petroleum refining industries are the only industries to use primary oils and feedstocks, changes to Grangemouth activity is also a key part of the upstream discussion.

In response to the decrease in demand and declining profit margins on exports, Petroineos mothballed one crude oil distillation unit and a fluidised catalytic cracker unit in 2021. The closures reduced capacity at the refinery by c30%, from 210,000 barrels per day (b/d) to 150,000 b/d, and also reduced staff count from c650 to c450 FTEs.

Going forward, Petroineos intends Grangemouth refinery only to produce enough downstream oil and oil products to supply the local market (Scotland, the north of England and Northern Ireland) and, with the absence of transport costs and tariffs, this will result in cheaper prices. In 2019, Scotland exported 2,961ktoe (27%) of total produced oil and oil products to ROW, compared to Scottish consumption of 6,576ktoe and exports to rUK of 1,670ktoe.

### Exports to ROW vs. rUK

Exports to the ROW have started to grow again over the five years to 2019 in line with stabilising production which has started to increase again over those years.

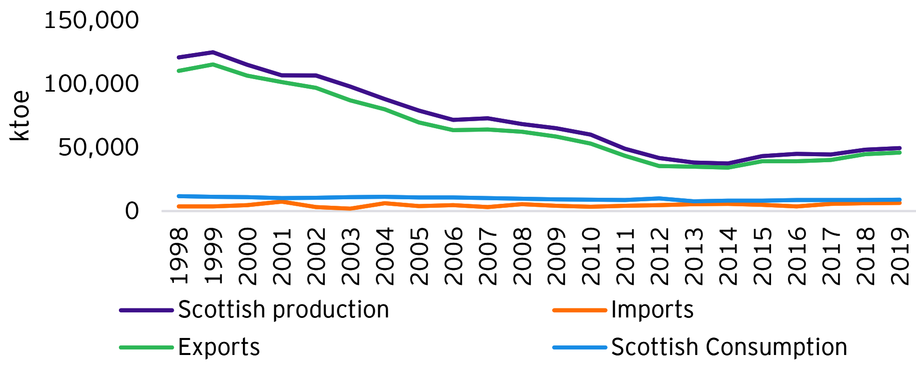
However, the shift in proportions between exports to the rUK and ROW is not stable and has changed over the years. This is due to the ever shifting global market for crude oil meaning trading decisions are very reactive and change daily. It is also driven by changing patterns in demand, which are expected to have a larger impact as the renewable sector continues to grow.

Other external market factors such as Brexit are unlikely to affect Scotland's crude oil trade as refineries act as a customs bonded warehouse, mitigating potentially disruptive geopolitical changes and any associated tax implications. The complex nature of the global market also protects Scottish crude oil trade somewhat, as demand remains high for ScotNS product from both EU importers and further afield. As upstream O&G is a major contributor to the Scottish economy, a higher oil price will support continued investment in that sector.

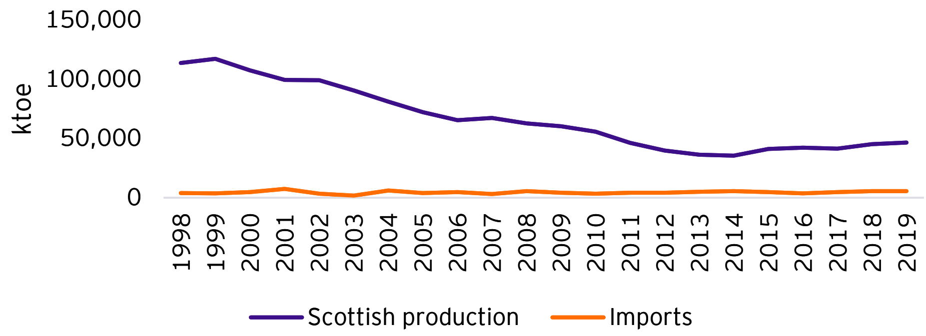
# Crude Oil
# Pattern of production, import and export



### Primary Oil Products




### Crude Oil - Imports vs. Production




## Scottish production

Scottish production of Primary Oil Products (which includes both crude oil and NGLs) has reduced significantly over the last 20 years as North Sea fields have depleted, from a peak total production of 125,024ktoe in 1999 to 49,412ktoe in 2019, a c60% drop. Despite this, production still remains a significantly larger inflow to the system than imports, as illustrated by the Sankey diagram.

The downward trajectory is driven by the recent decline in new investment and depletion of existing ScotNS fields. OEUK has stated that without any investment in fields and resources that have yet to be developed, the UK's crude oil output is likely to continue declining by up to 75% between now and 2030.

The ScotNS produces primarily high-quality, sweet and light crude oil with an American Petroleum Institute (API) gravity of 39.8%. API is an inverse measure which determines the weight of oil in comparison to water. If a liquid has an API gravity of more than 10 it is considered a light oil that floats on water. Sweet crude refers to oils with a lower sulphur content which are therefore easier to process into usable oil and oil products. There are also a number of active heavy oil fields in the CNS which account for roughly 10% of the UK's total crude production.

## Imports

Scotland has zero imports of crude oil from rUK, but 10% of the country's total energy source (production plus imports) is imported from overseas.

Total imports of crude oil have fluctuated somewhat over the years, but crucially these fluctuations do not correlate to declining production.

In 2019, Scotland imported a total of 5,367ktoe crude oil from overseas. A review of UK Port Freight data indicates that 1,935ktoe of this was shipped in from Nigeria, 1,026ktoe from Norway, 1,094ktoe from Russia, 658ktoe from the USA, with the rest coming in smaller volumes from Egypt and Togo.

This is broadly in line with data from the WoodMac Refinery Tool, which showed that only c30% of the total Primary Oil Products processed at Grangemouth in 2019 were sourced locally. According to the tool, significant imports came from Nigeria (29%), Russia (15%), United States (8%) and Norway (14%). We note that these figures are not exactly consistent with the port freight data due to differing methodologies between the two data sets, but they do show consistent import trends.

# Crude Oil
# Pattern of production, import and export (cont'd)



## End Use

The vast majority of Scotland's source Primary Oil Products are exported, with only 16% consumed in Scotland. Primary Oil Products are exclusively consumed by Grangemouth refinery where they are transformed into usable end products. None of Scotland's imported Primary Oil Products are subsequently exported. Scottish consumption of crude oil has reduced slightly over the last 20 years, but not in proportion to the decline in North Sea production. It is more likely that changes in demand are driven by recent shifts towards low-carbon alternatives, rather than directly as a result of reducing North Sea supply.

A very small portion of Primary Oil Products is neither exported nor transformed in the refining process. This "other" portion is made up of transfers – NGLs that are reclassified as they move between refineries and the petrochemical industry. Transfers do not leave the system as a usable end product. The "other" also consists of stock change – a very small portion of upstream Primary Oil Products which are held within the system in storage. Per the data, this amount held in storage equates to around half a day of annual Scottish consumption and is more likely to be products held at Grangemouth or crude oil awaiting transit, rather than supplies to be used in an emergency from an energy security perspective.

## Exports

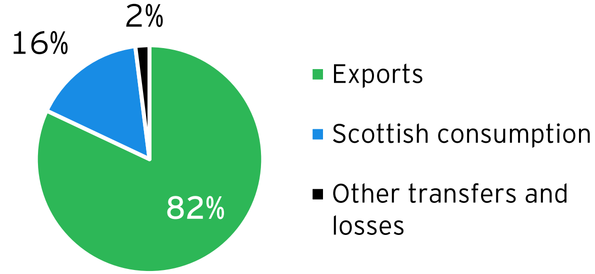
In 2019, Scotland exported 10,562ktoe of crude oil to rUK, and 32,934ktoe to ROW. Exports to ROW have reduced by 48% compared to 1998, while exports to rUK have dropped more drastically, a 78% decrease compared to 1998. These have both declined over the last 20 years in line with declining production, although they have started to stabilise in recent years. The figures suggest that rUK is more sensitive to declining Scottish production, compared to exports to ROW, although we note that the downward trajectory of ROW exports seems more closely to mirror the trajectory of declining Scottish production. It is also important to note that exports to rUK include production from ScotNS which is piped to terminals in England, and may subsequently be loaded for export to ROW but is not captured as such in these statistics.

A 2019 review of Port Freight Data suggests that the largest importers of Scottish crude oil were China, Germany, the Netherlands, Singapore and the USA, although the profile of countries changes year on year due to the nature of the dynamic global oil market.

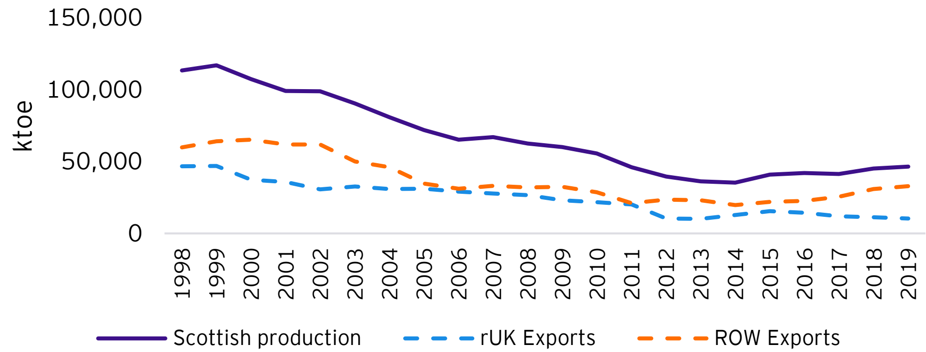
It is worth noting the potential influence of the Rotterdam-Antwerp effect regarding exports to the Netherlands. As one of the busiest ports in the world, Rotterdam port facilitates a significant portion of the UK's trade with the EU and further afield. Trade through such ports can sometimes be incorrectly recorded as the final destination for goods that are actually in transit to be traded on by commodity trading houses. A similar issue arises when looking at exports to rUK, as these may also be re-exported to ROW but not correctly captured in the data set.

As a net exporter of high-quality crude oil, traders in the Scottish O&G sector are protected somewhat from oil price increases. The UK as a whole on the other hand is a net importer and therefore benefits more when prices decline as they can make necessary purchases cheaper. Policy makers must consider such market factors when making decisions about the future of the Scottish O&G sector.

**Primary Oil Products – End Use (2019)**




**Crude Exports vs. Production**




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

# Greenhouse gas implications of import patterns



The key findings from this section are that ROW exports are most likely to be affected as production continues to decline, rather than imports or Scottish consumption. Imports have remained relatively constant and are influenced more by refining capacity and global oil market factors, while demand has remained relatively inelastic. Despite having less control over the external factors influencing imports, it is important for policy makers to understand the potential emissions implications should imports rise as production continues to decline.

### Transport Emissions – Driven by Distance

A 2020 study by the Centre for Transportation and Logistic at MIT looked at 28,000 global shipment samples to estimate each journey's carbon emissions and infer the carbon footprint of crude oil transportation.

The study concluded that the energy efficiency of a shipping vessel, as measured by the Energy Vessel Design Index (EVDI), does not have a strong effect on emissions per barrel of oil transported. The study concluded that the utilisation of a vessel's load capacity also does not have a significant influence on total emissions. The results concluded that the main driver of carbon emissions is distance, regardless of the efficiency and capacity factors.

Although Scotland has an ageing fleet of transport vessels, this study would suggest that efforts to reduce transport emissions should be focussed primarily on minimising the distance of shipments.

The average distance oil was transported in this study was 4160km, or 2,246nm (nautical miles). The study calculated average global emissions of 2.377 g$CO_2$e/tkm based on the global sample, or 4.4030 g$CO_2$/t-nm.

Using UK Port Freight Data, we reviewed 2019 shipping activity to and from the following major Scottish Ports:

- Aberdeen
- Cairnryan
- Clyde
- Cromarty Firth
- Dundee
- Forth
- Glensanda
- Loch Ryan*
- Orkney
- Peterhead
- Stranraer*
- Sullom Voe

* Stranraer port closed in November 2011. Its operations were transferred to neighbouring Loch Ryan Port.

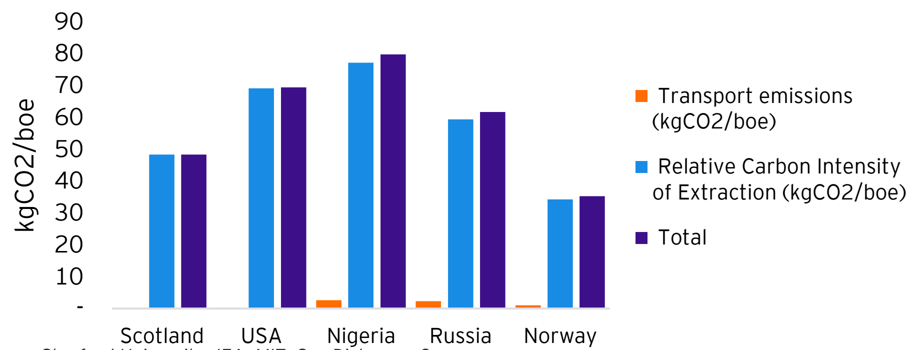
Using distances between Scotland's largest port, Forth, and the respective countries' main cargo seaport, we calculated a weighted average distance of 2,198nm for Scottish O&G imports, broadly in line with the study's findings. Scottish exports in 2019 covered a significantly larger average distance due to the volume of exported goods to the Far East (China, Singapore and South Korea). However, we note that the pattern of import and export destinations is volatile due to the dynamic nature of the global oil market.

### Relative emissions of Global Crude Oil Extraction

It is also important to consider the relative emissions from the extraction of crude oil in different countries. Using the MIT average emissions/tnm, we have calculated a carbon intensity factor for the transportation of Scotland's top crude oil imports (from Nigeria, Norway, Russia and USA). We have added this to the relative emissions of crude extraction for each of the countries (per the Stanford data in Section 5) to give an illustrative total carbon intensity per barrel of oil imported from each country.

The figures suggest that the total emissions impact of importing crude oil from Norway is in fact less than using ScotNS crude oil, but the emissions impact of importing from any of the other countries is higher. This is because the relative emissions of the source country's extraction process is the main component of total emissions.

### Relative emissions of imports




Source: Stanford University, IEA, MIT, Sea Distances Org

| Country of origin | Transport emissions ($kgCO_2/boe$) | Plus relative Carbon Intensity of Extraction ($kgCO_2/boe$) | **Total Carbon Intensity ($kgCO_2/boe$)** |
|---|---|---|---|
| Scotland | - | 48.34 | **48.34** |
| Nigeria | 2.62 | 77.10 | **79.72** |
| Norway | 0.62 | 34.27 | **34.88** |
| Russia | 2.29 | 59.35 | **61.65** |
| USA | 1.94 | 69.14 | **71.08** |

# 9 Upstream

# Primary Oil Products – Natural Gas Liquids (NGLs)

# Natural Gas Liquids
# Trends in production, use and exports



## NGLs and their uses

North Sea upstream O&G operations have historically generated a significant amount of Natural Gas Liquids (NGLs) as well as crude oil. These NGLs are therefore also considered wihtin the Primary Oil Product data set. NGLs such as ethane, propane, butane and condensate are hydrocarbons composed exclusively of carbon and hydrogen. Common uses for these NGLs are as follows:

- **Ethane** is a naturally gaseous straight-chain hydrocarbon ($C_2H_6$) found in natural gas and refinery gas streams. It is primarily used, or intended to be used, as a chemical feedstock and converted into ethylene. Ethylene is the base material for the manufacture of plastics used in food packaging, medical equipment, car parts and many more products in our day to day lives.
- **Propane** is a hydrocarbon containing three carbon atoms ($C_3H_8$). It is gaseous at normal temperature but generally stored and transported under pressure as a liquid. It is used mainly for industrial purposes, but can also be blended with petrol as transport liquid petroleum gas (LPG), and in some domestic heating and cooking.
- **Butane** is a hydrocarbon containing four carbon atoms ($C_4H_{10}$). It is additionally used as a constituent of liquid petroleum gas (LPG) to increase vapour pressure, and as a chemical feedstock.

Ethane sourced from US shale gas is also separated at source and imported to Scotland in a liquefied state (which is why it is not included in the natural gas data set).

## Production and Imports

Scotland historically did not import any NGLs as production came directly from North Sea fields or the cracking process at NGL facilities such as Mossmorran, discussed in more detail in Section 9. Scotland only began importing when production started to decline more sharply in the mid 2000s, indicating a stronger correlation between declining production and NGL imports than the crude oil case.

In 2014, Ineos received planning permission to build an ethane storage tank at its site in Grangemouth. The tank was designed to hold over 60,000 cubic metres of ethane, a key feedstock for petrochemical manufacturing, shipped from the Texas Gulf to substitute for declining North Sea supplies and facilitate the expanding petrochemical facilities.

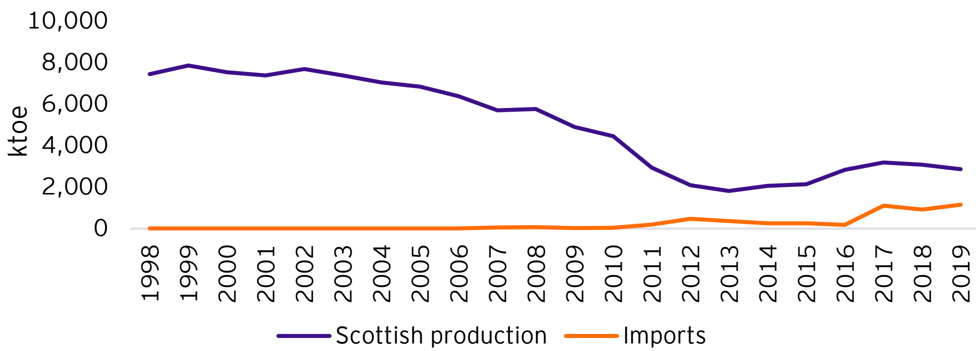
Port Freight data indicates that the majority of Scotland's imported NGLs come from the US. US exports of ethane have increased from nearly nothing in 2013 to an average of 450,000 b/d in 2019. In 2015 the US surpassed Norway, the only other country to internationally export ethane, to become the world's top exporter of ethane. The US benefits from economies of scale which filter into the price of its ethane exports, meaning that it is not only the need to import ethane to compensate for declining Scottish production that drives imports, but also the price advantage.

Imports of NGLs from the US also contain a small portion of ethane derived from US shale gas. Although shale gas is primarily composed of methane, a natural gas, it is shipped to Scotland in a liquefied state and so is included in the data set as an NGL. Shale gas is extracted by hydraulic fracking of bedrock, a process which is currently banned in Scotland and therefore could not be replaced by Scottish production. Grangemouth was one of the first refineries in the UK to import shale gas from the US in 2016, extracting ethane from the gas to create plastic pellets used in general manufacturing.

Therefore, imports of NGLs are driven by declining North Sea production as well as price advantage of importing from the US, unlike imports of crude oil which are driven solely by price advantage of trading on the global market and not at all by production levels. In both cases the same principle applies that the wider market factors at play are ultimately out of Scottish policy makers' control.

The data shows the increase and levelling off of NGL production levels since 2013 while imports have continued to rise. This is likely due to the construction of Ineos' new ethane tanker, but the demand side will be explored fully in Chapter 2.

NGL – Imports vs. Production




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

# Natural Gas Liquids
# Trends in production, use and exports (cont'd)

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## Exports

In 2019, Scotland exported 809ktoe of NGLs to rUK, and 1,639ktoe to ROW, significantly smaller volumes than the export of any other product, but a significant portion of total NGL production.

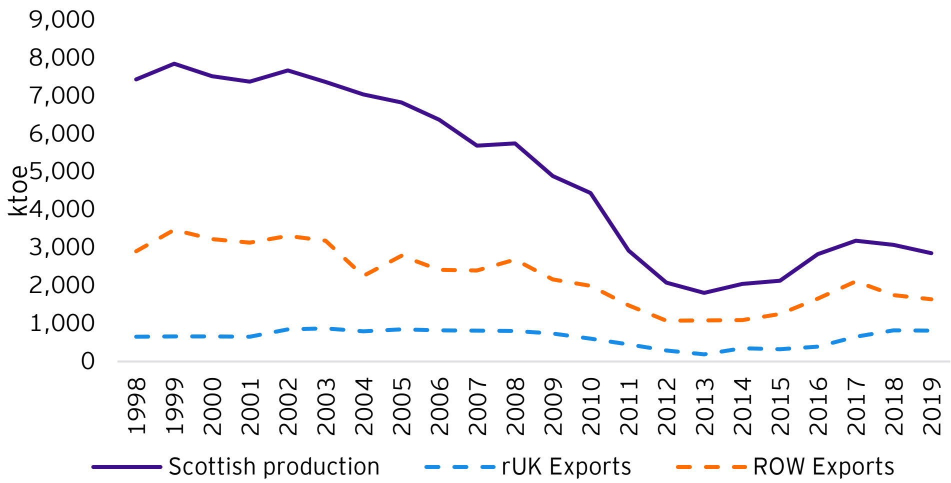
A 2019 review of Port Freight Data suggests that the largest importers of Scottish NGLs were the Netherlands, Belgium and France. This has been the case for a number of years, although we note again that the Rotterdam-Antwerp effect could be at play.

The graph indicates that the downward trajectory of NGL exports to ROW is more in line with declining production than the trajectory of exports to rUK. This is similar to the relationship between crude oil exports to ROW and crude oil production, and is also impacted by similar global market factors which result in Scotland both importing and exporting NGL products depending on what is most economically advantageous on the market.

These findings indicate that ROW exports are most likely to be affected by the continuing decline of North Sea production, as opposed to seeing big changes to imports, domestic demand or rUK exports.

Scotland currently benefits from its position as a net exporter to ROW in the midst of rising commodity prices. However, if ROW exports continue to decline as a result of declining North Sea production and Scotland begins importing more O&G goods than it exports, it would no longer be sheltered from price increases.

### NGL Exports vs. Production




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

# 10 Natural Gas

# Natural gas
# Gas Network and Production




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

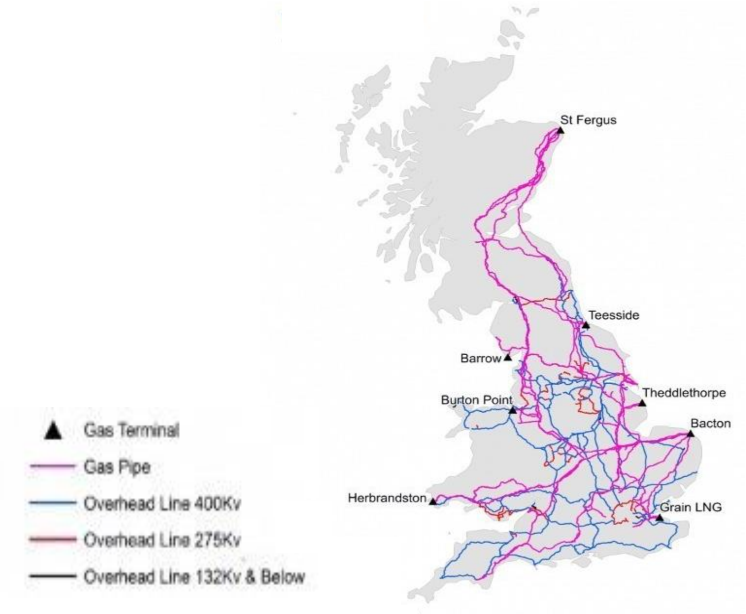
Natural gas was first discovered in the North Sea in the 1960s, and by the late 1970s was the preferred heating source for both industry and domestic properties following a UK Government campaign to move the country away from coal and town gas consumption. ScotNS production of natural gas peaked in 2000 and has since been in decline, as shown in the graph above. Scotland's electricity generation became coal-free when the Longannet power station, the last and largest coal-fired power plant in Scotland, ceased operations in 2016.

## Gas Network Infrastructure

National Grid is the Gas System Operator for the UK and is responsible for ensuring that the gas system is balanced across each day, that it is secure and can continue operating in the event of a fault. National Grid also own the Gas National Transmission System (NTS) which receives high pressure gas across the UK from offshore pipelines and LNG terminals at Scotland's only gas terminal, St Fergus.

St Fergus Gas Terminal (SFGT) is located on the north east coast of Scotland just north of Peterhead. The St Fergus area is the landfall for several major North Sea assets, including the Total operated Shetland Gas Plant (SGP) at Sullom Voe on Shetland and the Shell operated SEGAL gas terminal and the Ancala operated SAGE gas terminal. The St Fergus area provides a connection point for the offshore pipelines from these facilities, including FUKA (Frigg UK Association) pipeline, Vesterled pipeline, the SIRGE Pipeline and the Ancala pipeline, providing a route for gas extracted from both Scottish and Norwegian fields in the North Sea to the NTS. From there, it is distributed further via the National Grid onshore pipe network, as shown on the map below.

Eight Gas Distribution Networks (GDNs) transport the gas into UK homes and businesses via lower pressure pipes. Only one of these GDNs is In Scotland – SGN.




Source: National Grid – Network route maps Network route maps | National Grid Gas

It is also important to note that Scotland is not only linked to the rest of the UK via the National Grid, but to the rest of Europe via the UK-Ireland Interconnector and the Bacton Zeebrugge Interconnector. The former is captured in the natural gas export figures because it is linked to the gas terminal at Moffat, but the latter is not directly highlighted in the data because the terminal meeting point is in Norfolk, England. Unlike the global oil market, gas prices are set more regionally using the UK National Balancing Point (NBP). The UK NBP price is extensively used as an indicator of price for Europe's wholesale gas market, and indicates the interconnectedness of Scotland with wider European gas networks.

Scotland does not have an independent gas network. It is completely integrated with rUK via the NTS, and with the European markets via Norwegian fields, the UK-Ireland interconnector and the Bacton Zeebrugge Interconnector.

# Natural gas
# Imports trends and Seasonality of demand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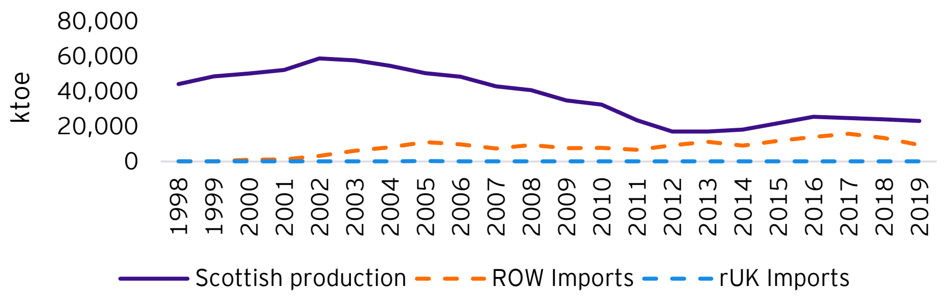
### Natural Gas – Imports vs. Production




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

### Imports

Although ScotNS production has declined, Scottish demand for natural gas has remained relatively steady over the last 20 years. As a result, Scotland has had to supplement the declining production by importing natural gas from Norwegian fields via the FLAGS, SAGE and Vesterland pipelines. Imports have steadily increased since the early 2000s, with Scotland importing 9,497ktoe of natural gas in 2019, 29% of the total gas supply.

Scotland produced 23,129ktoe of natural gas in 2019, considerably higher than Scottish demand of 9,343ktoe.

The figures suggest that there is not a shortfall in production that needs to be replaced by imports. The reason Scotland imports Norwegian gas despite producing sufficient volumes to meet demand is that the ScotNS has historically supplied not only Scotland, but the rUK. The offshore gas pipe network was originally constructed to transport directly from the ScotNS to rUK gas terminals rather than being directed to Scottish terminals. For example, Teesside Gas Terminal operated by ConocoPhillips receives gas directly from the Central North Sea.

A number of the major North Sea pipelines supply Scotland's SFGT with gas extracted from both ScotNS fields and Norwegian fields, due to their close proximity. Therefore, the simple explanation for why Scotland imports natural gas despite seemingly sufficient production is the physical infrastructure of the offshore pipelines. The pipe infrastructure makes it difficult to distinguish exactly how much Scottish, rUK and Norwegian gas is consumed across the UK as it moves back and forward across the grid.

With growing pressure to halt any new exploration and domestic drilling in the North Sea, the NSTA Climate Change Committee forecasts suggest that the UK's gas imports will increase dramatically over the next 30 years. This, coupled with the fact that Scotland has no gas storage facilities, has brought energy security under the spotlight in recent months as fears of a potential supply crunch has continued to push up gas prices.

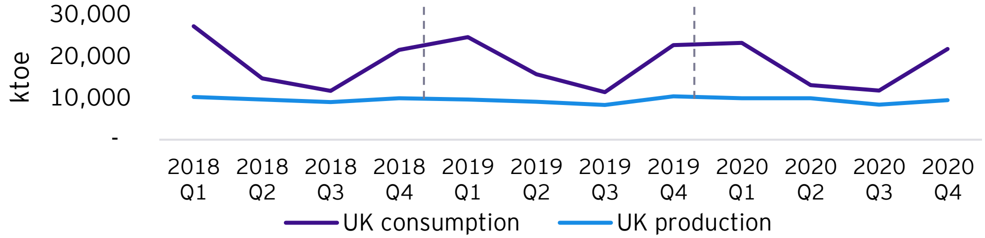
The NBP is not just used in Scotland but is also used as an indicator for the European market, given the interconnectivity of UK and European gas networks. Although Scotland produces much of its own natural gas to meet domestic demand, this relationship with the wider European market and gas prices has led to even more scrutiny on energy security. As the conflict in Ukraine continues, mainland Europe has sought to replace the previous natural gas supplies from Russia with gas from Norwegian fields. In the short term this has meant a spike in prices, but long term could also mean that any reduction in Scottish natural gas production would need to be met by imported LNG, rather than Norwegian piped natural gas as has previously been the case. Although Scottish gas prices are more closely linked to the European gas networks, they are still affected by global events.

### Seasonality of demand

The data suggests that a very small portion of imported natural gas comes from rUK, which is counterintuitive considering the volume of exports from ScotNS to rUK. The reason for this anomaly is twofold. Firstly, Scotland is part of the UK National Grid and does not have its own separate gas network that recognises the land border. Secondly, unlike production levels, gas demand fluctuates seasonally. As discussed in the introduction, part of the National Grid's function is to ensure that the gas system is balanced across each day and so gas is often moved back and forward between Scotland and rUK to meet fluctuating daily demand.

The volatile nature of gas consumption across the UK National Grid highlights the need to consider energy security as Scotland currently has zero storage of gas.

### Seasonality of Gas Demand




Source: BEIS Energy Trends 4.1 Natural gas supply and consumption

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# End use and Export trends

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### Scottish consumption

Scotland consumes proportionally more gas than oil products. In 2019, total Scottish consumption of refined oil and oil products was 6,575ktoe, compared to natural gas consumption of 9,343ktoe. Scottish consumption of natural gas equates to 29% of natural gas primary energy (imports plus Scottish production).

Total Scottish consumption has remained relatively steady over the last 20 years in comparison to declining Scottish production. We will explore demand drivers in more detail in Chapter 2; however, the section below gives a brief introduction to the key consumers of natural gas in Scotland.

### Energy Industry

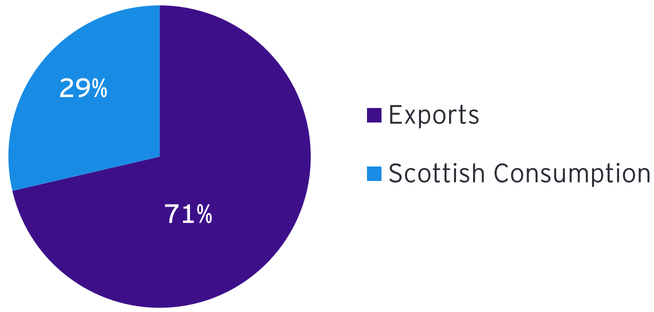
Natural gas is consumed in many different ways, but upstream O&G producers that use gas in the extraction process account for 42% of total Scottish consumption of natural gas in 2019. Energy Industry use also includes use by refineries.

As the upstream process needs to use natural gas in the course of producing O&G products, the NSTA often report "net natural gas" figures in its production data. Net natural gas production refers to gross production less producers' own use, i.e., the portion consumed by the process and not available for sale to end users.

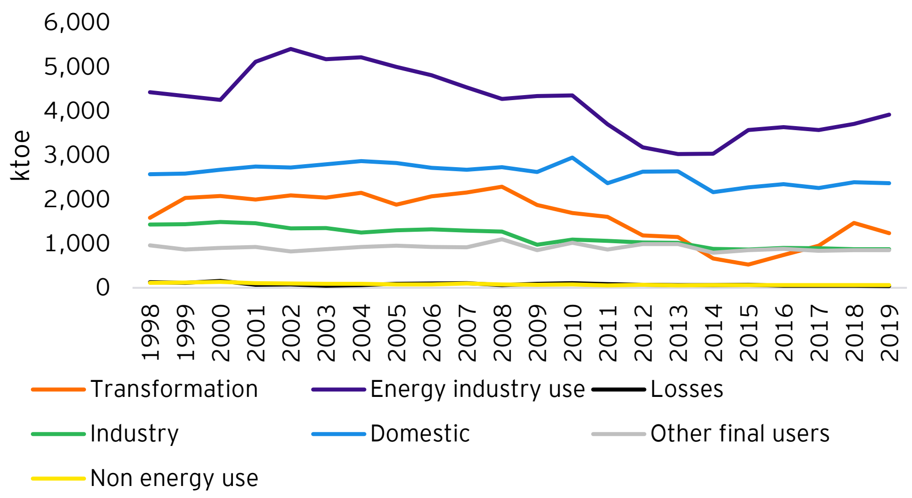
### Domestic

Natural gas also continues to play a large role in heating Scotland and is the primary fuel source for domestic properties in Scotland , with approximately 79% of Scotland's homes currently using mains gas for heating. This figure is lower than the UK average of 85%, and is likely to continue reducing as SG invests in Low Carbon initiatives such as the Heat Network Fund. According to OfGem, 13% of the remaining properties that do not use gas instead use electrical heating systems, predominantly in urban areas. The remaining households use other non-gas heating fuels, such as heating oil, liquid petroleum gas (LPG), solid fuels or district heating networks. These fuel types are more common in remote rural areas and are not regulated in the same way gas and electricity are, so the exact usage is less clear.

Natural Gas - Total End Use (2019)




Scottish Consumption of Natural Gas Over Time




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

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**Transformation (i.e., electricity or heat generation)**

13% of Scotland's consumption of gas relates to use for electricity or heat generation. The primary demand is to supply Electricity generators, but a small portion also relates to the use of gas for heat generation in district heating schemes across Scotland.

**Industry**

Industry accounts for 9% of Scotland's gas consumption as it is used as a source of both heat and power in the production of goods such as iron and steel, non-ferrous metals, mineral products, chemical products, vehicles production, food, beverages, textiles, leather, paper, printing, and in construction.

**Other Final Users**

Other final users include Agriculture, where natural gas is used to power machinery and irrigation systems, the commercial sector which uses gas to heat buildings and water, and public administration where it is used to deliver public lighting and other public services.

**Losses**

Natural gas losses occur downstream and include metering differences, theft and leakage. These have been estimated by BEIS using the LDZ Shrinkage Assessment and Adjustment report (published by National Grid), with the Scottish figure apportioned relative to Scottish natural gas consumption.

**Non energy use**

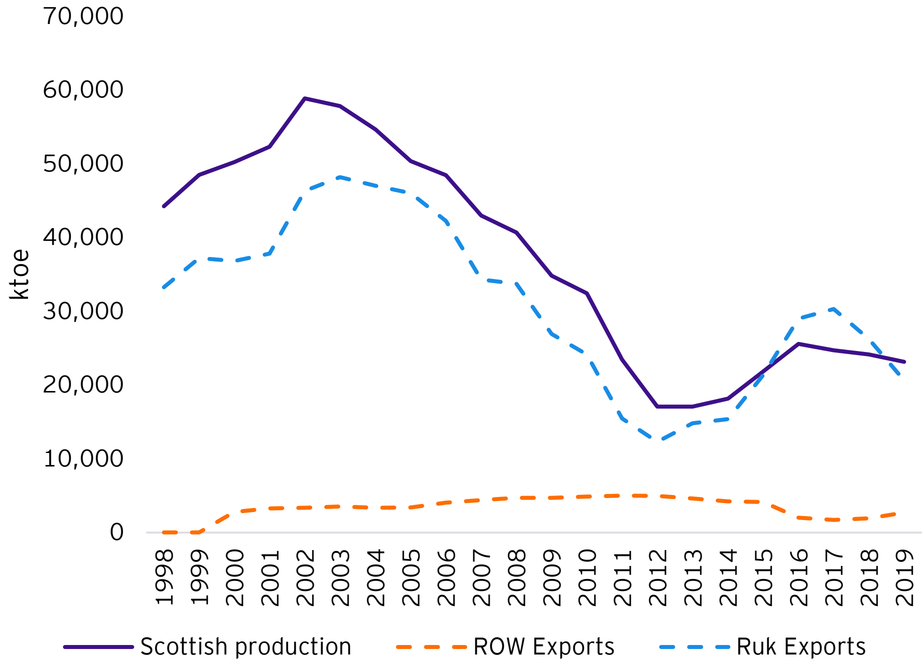
Non-energy use refers to gas used as feedstock for petrochemical plants in the chemical industry as raw material to produce ammonia (an essential intermediate chemical in the production of nitrogen fertilisers) and methanol.

**Exports**

The majority of Scotland's production of natural gas is exported to rUK. Natural gas accounted for 61% of Scotland's total O&G exports to rUK in 2019. Exports of natural gas to rUK have been closely correlated to Scottish production and therefore have been heavily impacted by the declining North Sea supply. Scotland's exports of natural gas to ROW are minimal, with only a small percentage of Scottish natural gas exported to the Republic of Ireland via the UK-Ireland Interconnector. However, we note that it is possible that some Scottish exports to rUK are subsequently exported to ROW via the IUK interconnector with Belgium or the Balgzand to Bacton Line (BBL) to the Netherlands, and that these re-exports are not accurately captured in the data set.

Natural gas production in the UKCS began to increase from 2014, with 2015 seeing the largest year on year increase since production peaked at the beginning of the century. This was due to the development of new gas fields as well as lower maintenance levels than 2014. We note that the data shows that exports to rUK actually exceeded Scottish production between 2016 and 2018. This is an example of the National Grid balancing demand across the system. Upstream exports go directly from ScotNS fields to gas terminals in rUK, as per the pipe infrastructure discussion, but any Norwegian gas imported to Scotland and not used can also be subsequently re-exported to rUK, causing exports to be higher than production levels.

**Natural Gas – Exports vs. Production**




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

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# Downstream
# The Refining Process and End Products

# The Refining Process - Oil and Oil Products Production and Import trends

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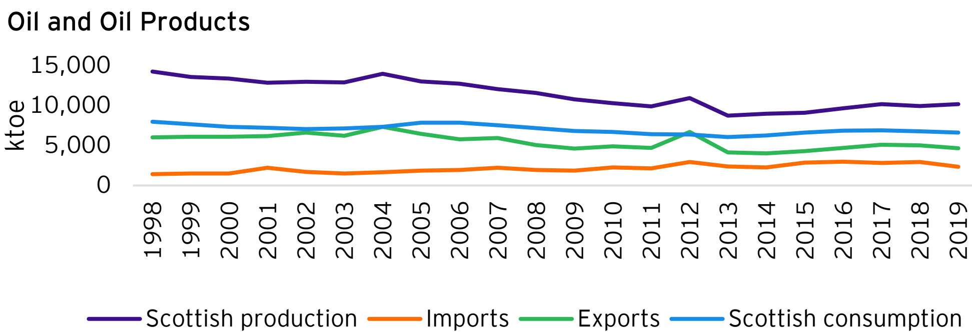


Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

### Scottish Production – Grangemouth and Mossmorran

Oil refineries have operated in the UK for over 100 years converting crude oil into usable oil and oil products such as road and aviation fuel, lubricants and greases.

The global expansion of the refining sector led to easier trading of transport fuels, resulting in a significant reduction in refinery operating margins. In the UK this saw the closure of many refineries, the total number reducing from 19 to 7 over the last twenty years. Only 6 of the remaining 7 are classed as 'major' refineries. These are:

- ExxonMobil – Fawley refinery
- Essar Energy plc – Stanlow refinery
- Phillips 66 Limited – Humber refinery
- Prax – Lindsey refinery
- Valero Energy Corp – Pembroke refinery
- Petroineos – Grangemouth refinery

Grangemouth refinery is owned by Petroineos and is situated on the Firth of Forth on Scotland's east coast. One of the largest facilities of its kind in Europe, Grangemouth produces oil and oil products and is Scotland's only crude oil refinery, as well as at its largest petrochemical plant. At its peak Grangemouth had the capacity to produce around seven million tonnes of fuels.

Grangemouth has undergone significant operational changes over the last 20 years, both to tap into the growing petrochemical market and to make plant operations greener. Grangemouth was the first to introduce Ultra Low Sulphur Diesel (ULSD) and Ultra Low Sulphur Petrol (ULSP) to the UK market by utilising sweet (low sulphur) North Sea crude. In 2019, Ineos announced it was investing £350m in a new state of the art energy efficient power plant to modernise steam and power generation to the Grangemouth petrochemical and refining plants. Plans are also in place for Ineos to invest more than £1bn in blue hydrogen.

### Plant operations

Grangemouth also has a number of petrochemical plants, such as the KG Ethylene plant, which produce around 1.4 million tonnes of petrochemicals per annum. Petrochemicals are also produced at the Fife NGL plant operated by Shell and the Fife Ethylene plant (FEP) operated by ExxonMobil at Mossmorran. Here, feedstocks created by the crude oil distillation process and the Mossmorran NGL Fractionation plant are separated into ethane, propane or butane and then cracked to create NGLs such as ethylene, propylene or butylene, which are commonly used as the building blocks of plastic.

The data indicate that total Scottish production of oil and oil products has declined over the last 20 years. This is not as sharp a decline as we have seen in Primary Oil production, but is related partly to declining North Sea supplies.

The data show two notable spikes in the oil and oil product production trend which were preceded by spikes in the global oil price. There have also been significant operational changes at the Grangemouth facility over the period:

- 2000-2002 Various expansions at the Grangemouth site was commissioned, including a new polypropelene plant (PP3), further extension of the KG ethylene plant and a second ethanol plant.
- 2004-2005, BP divested its worldwide olefins and derivatives (O&D) business, including the refinery and petrochemical facilities at Grangemouth. A new company called Innovene was incorporated to run the divested business, which was subsequently bought by Ineos. A second sulphur recovery unit (SRU) was installed.
- 2011 Ineos entered into a joint venture (JV) with Petrochina. The new company, Petroineos, owns and operates Grangemouth refinery to this day.

Ineos has continued to own, operate and expand the Grangemouth petrochemical plant. In 2015, an agreement between Ineos and ExxonMobil to supply US shale gas ethane from Grangemouth to the FEP at Mossmorran was announced. These production trends are consistent with increased imports of NGLs from the US discussed in Section 8.

Total oil and oil products production has declined, but not as steeply as recent Woodmac data on refinery operations, suggesting that the reduction to refining capacity has been offset somewhat by increasing petrochemical production. Recent changes to refinery operations are discussed in more detail in the following pages.

# The Refining Process – Oil and Oil Products Production and Import trends (cont'd)

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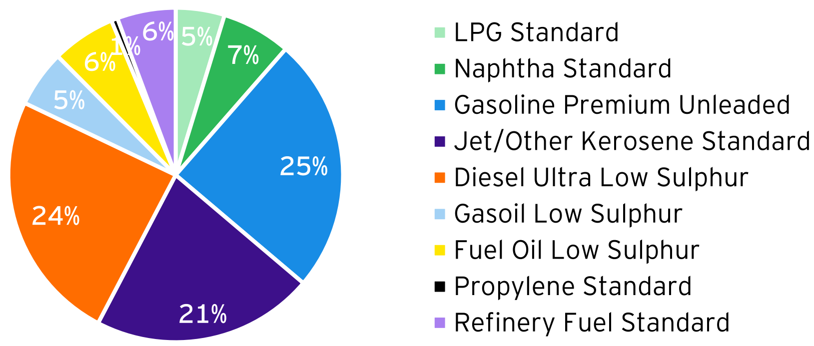
Although petrochemical operations have been expanding, the crude oil refinery at Grangemouth, like the rest of the UK refining industry, has suffered from a decrease in demand for fuels during the COVID-19 pandemic. Per the WoodMac Refinery Evaluation Model (REM), Grangemouth's average daily yield dropped c50% from 192,244 b/d in 2018 to an average of 97,178 b/d in 2020.

In response to the decrease in demand, Petroineos mothballed one crude distillation unit (CDU) and a fluidised catalytic converter (FCC) unit in 2021. The CDU is the first processing unit in the refinery, which splits incoming crude oil into various fractions for further processing. The FCC then cracks the heavier fractions into end products such as propylene, gasoline, naptha and diesel. The closures reduced capacity at the refinery by c30%, from 210,000 b/d to 150,000 b/d, and also reduced staff count from c650 to c450 FTEs. Broadly speaking, the closures will have reduced production across all of the refinery's output products detailed in the chart below, with a marginally higher reduction in the FCC outputs.

Going forward, Petroineos intends that Grangemouth refinery will only produce enough downstream oil and oil products for consumption in Scotland, the north of England and Northern Ireland. In 2019, Scotland exported 2,961ktoe (27%) of total produced oil and oil products to ROW, compared to Scottish consumption of 6,576ktoe and exports to rUK of 1,670ktoe.

### Grangemouth Refinery Product Mix (2019)



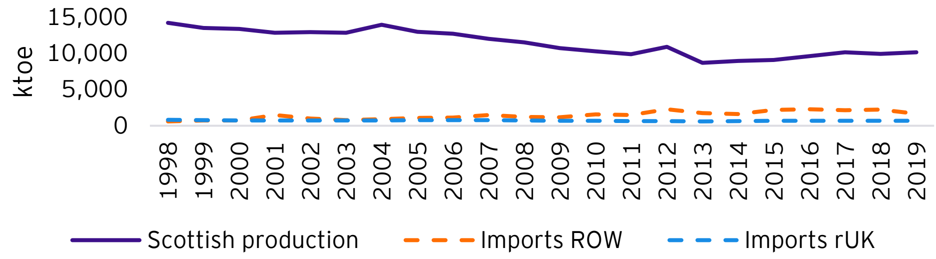

Source: WoodMac Refinery Benchmarking tool

The product mix chart summarises the mix of outputs from the crude oil refinery only. Due to limited data, we do not have a clear picture of the exact product mix coming from the Grangemouth or Mossmorran petrochemical plants, although we understand that the following are produced:

- **Ethylene** – the essential intermediate (building block) employed in the petrochemical industry. It is used in the manufacture of the plastic: polyethylene (on site) and other chemicals in the petrochemical industry (e.g., emulsion paint, car fuel tanks, resins, adhesives)
- **Propylene** – intermediate (building block) used to manufacture, e.g., the plastic polypropylene (on site)
- **Polyethylene** – typical applications include plastic bottles (milk, shampoo), wrappers, food film etc.
- **Polypropylene** – carpets, carpet backing, DVD cases, cabling, water pipes etc.

Chapter 2 will explore demand and end user markets in more detail.

### Oil and Oil Products – Imports vs. Production




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

### Imports

Scotland imports oil and oil products from both rUK and ROW, albeit in much smaller quantities than what is produced from Grangemouth and Mossmorran facilities. Total imports from rUK are primarily made up of oil and oil products, as opposed to crude oil or natural gas. This is because some of Scotland's road fuel is supplied by other rUK refineries through exchange agreements.

# The Refining Process – Oil and Oil Products End use and Export trends



Due to the top-down methodology used in calculating the Scottish portion of total UK imports, it is difficult to ascertain the exact product mix of Scottish imported petroleum products from ROW. At a UK level we note that the vast majority of imported petroleum products relate to DERV fuels (40% of total imported). The second-most imported petroleum product to the UK is aviation turbine fuel, which makes up 29% of the total. It is our understanding that Scottish downstream production from Grangemouth supplies 100% of the country's aviation fuel requirements, and so Scottish level imports will not mirror the same product-mix as UK imports.

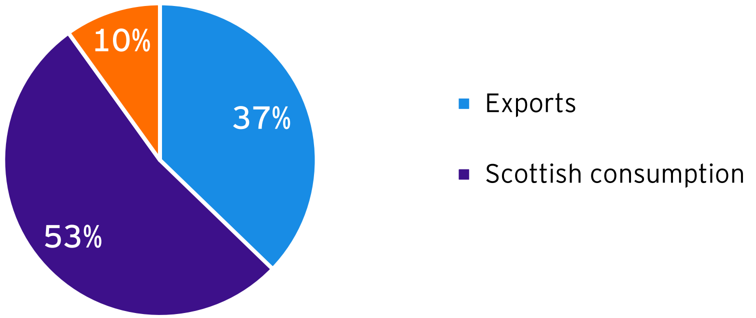
Our review of Port Freight data indicates that the majority of Scotland's imported petroleum products come from the Netherlands and Belgium. We note that these source countries may not be entirely accurate, again due to the Rotterdam-Antwerp effect. However, we do note that downstream petroleum products account for only 13% of Scotland's total O&G imports and have been less volatile than Primary Oil products imports over the last 20 years.

## End use

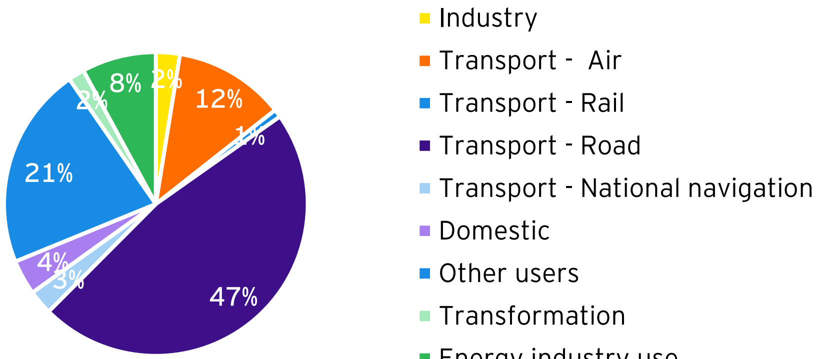
In 2019 the majority of Scotland's oil and oil products were consumed domestically. We note that this will have increased proportionally since 2019 with the recent reduction of Grangemouth's production capacity. Of this domestic consumption, road transportation accounts for 47%. At a UK level 67% of road consumption is DERV, and the other 33% is petrol. BEIS sub-national road transport fuel consumption statistics (2019) gives a breakdown of road transport consumption at a regional level based on vehicle type (e.g., buses, personal cars, motorcycles and HGVs) but does not clearly split out Scottish road transport consumption in terms of the different fuel types identified above.

Scottish consumption of downstream oil and oil products has been relatively steady over the last 20 years, trending downwards slightly but not in line with the fluctuations in production over time. This relationship suggests that fuel consumption demand has been steady from road users, domestic households and industries.

**Oil and Oil Products – End Use (2019)**




**Oil and Oil Products – Scottish Consumption (2019)**




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

# The Refining Process – Oil and Oil Products End use and Export trends (cont'd)

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Other transfers and losses are primarily made up of marine bunkers – fuel for ships carrying exports from Scottish ports to ROW, and a very small portion of stock change and feedstock transfers back into the upstream process.

Non-energy use refers to the outputs from petrochemical operations discussed in previous pages. These have been calculated based on UK BEIS data and apportioned based on Scotland's share of total UK refining capacity. As mentioned previously, the exact mix of petrochemical products is not clear from the data available. Demand from the petrochemical industry will be explored in more detail in Chapter 2.

## Exports

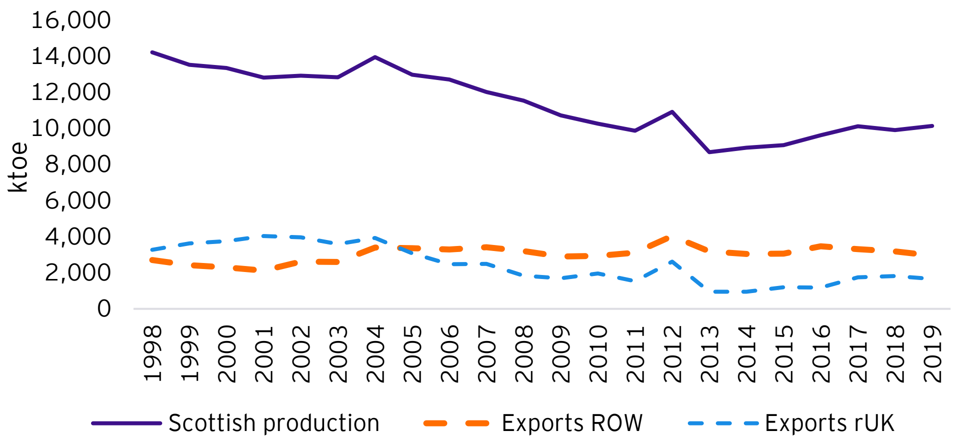
In 2019, Scotland exported 1,670ktoe of oil and oil products to rUK, and 2,961ktoe to ROW. The exact product mix of Scottish exports is not clear. BEIS data suggests that the UK's largest O&G exports are of petrol, diesel and marine diesel oil. However, we would expect a slightly different product mix in Scotland. For example, we know that Grangemouth supplies 100% of Scotland's aviation fuel needs, but that some of our road fuel is imported from rUK. It is also worth noting that Scottish exports to rUK may be subsequently exported to ROW but not accurately captured in the data set.

A 2019 review of Port Freight Data suggests that the largest importers of Scottish oil and oil products were rUK, Netherlands, Belgium and the Republic of Ireland. This has been the case for a number of years, although the Rotterdam-Antwerp effect could be at play.

The graph indicates that the downward trajectory of oil and oil product exports to rUK are largely in line with production trends, showing the same spikes in 2004 and 2011, and the same overall downward trend. Exports to ROW over time also spike in line with production, but have not seen the same decline over time and in fact have increased marginally over the last 20 years.

Similarly to crude oil and NGLs, exports of oil and oil products will feel the largest effect of the continuing decline in production, as opposed to seeing a reduction in imports or domestic demand. Exports have always tracked most closely to production, partly because there is an economic benefit to the decision to reduce exports, as it is the refinery which bears any costs of shipping. Profit margins on crude oil imported via the Forties Pipeline have reduced as production has declined, causing an increase in relative costs of each barrel of oil exported. These increased costs, coupled with reduced demand as a result of COVID-19, have resulted in Pertroineos' recent reduction of refining capacity which will further cut exports.

### Oil and Oil Products – Exports vs. Production




Source: SG Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019

# The Refining Process – Oil and Oil Products Infrastructure



## Infrastructure and Export links

### Grangemouth

The refinery at Grangemouth plays a leading role in supplying Scotland's fuel demand, and is of strategic importance to Scotland's energy supply and regional economic development. The refinery is connected to both the Forties Pipeline system and two pipelines that run between Grangemouth and the Finnart Ocean Terminal on the Firth of Clyde. At its peak it has had a refining capacity of 210,000 barrels per day, reduced to 150,000 post-mothballing.

The Forties Pipeline system is an integrated O&G transportation and processing system that utilises more than 500 miles of pipeline to transport crude O&G from more than 80 offshore fields for processing at the Kinneil Terminal at Grangemouth. Once processed, O&G is then transported to Forties and the Petroineos refinery.

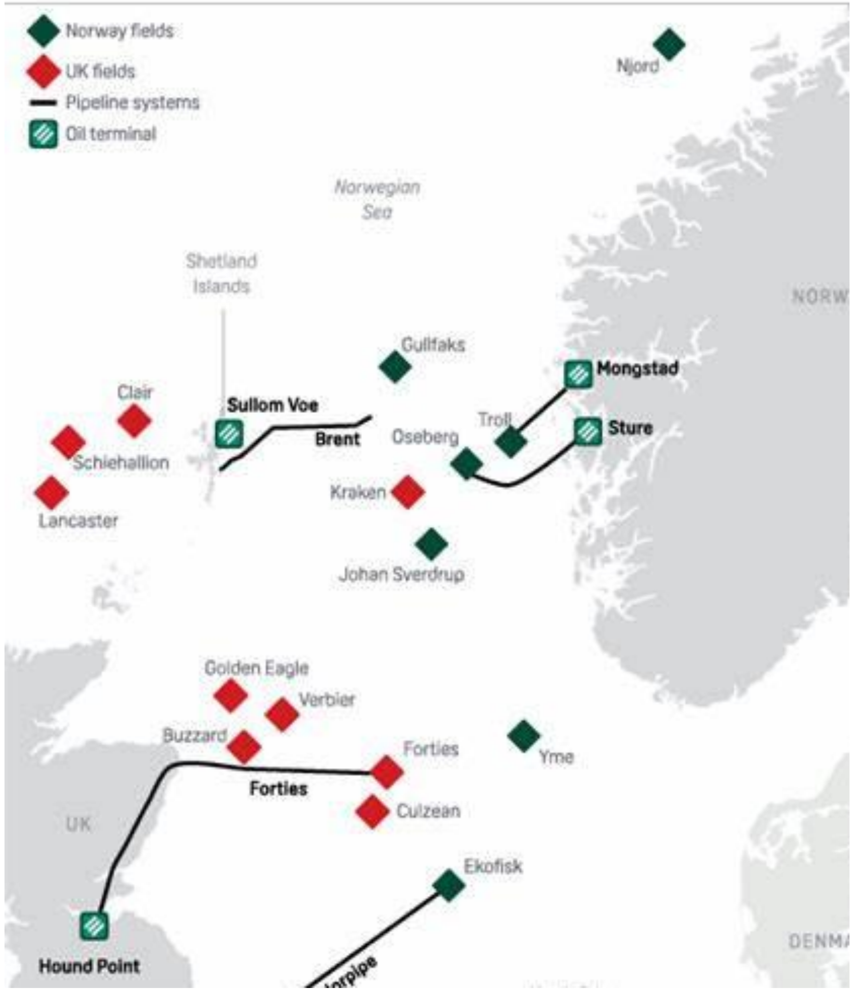
The pipelines that run between the refinery in Grangemouth and the Finnart Ocean Terminal enable both import of upstream Primary Oil Products (e.g. raw crude oil) to Grangemouth and subsequent export of downstream oil and oil products from Grangemouth. The Finnart Ocean terminal accommodates some of the world's largest crude carriers (VLCC's) weighing up to 320k tonnes.

It is unclear the exact route that refined oil and oil products take when leaving the plant, but UK Port Freight data suggests that 4,336ktoe out of the total 4,631ktoe oil and oil products ultimately exported from Scotland in 2019 left via shipping tankers. 2,556ktoe of this departed from Forth Ports, 1,289ktoe from Clyde and 492ktoe from Aberdeen and Peterhead.

### Mossmorran

Both Mossmorran plants form part of the North Sea Brent O&G field system, linked by pipeline to St Fergus and the marine terminal at Braefoot Bay. The plants are currently reliant on the production from the North Sea's depleting fields. Natural gas is pumped ashore from the North Sea to a terminal at St Fergus in Aberdeenshire. Methane is separated and circulated on the NTS, while other gases such as ethane are pumped 139 miles to the Mossmorran facilities. Once processed, liquified propane and butane are transported to the marine terminal at Braefoot Bay for loading onto ships for export.

NORTH SEA FIELDS AND PIPELINES




Source: S&P Global Platts

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### Introduction

In this section, we analyse the ScotNS in a global context, in particular we consider its contribution to the global O&G section, its relative emissions intensities and drivers and barriers to investment.

### Scottish and UK hydrocarbon production in a global context

As set out in Section 3, Scottish production and associated GVA has declined significantly since its peak. At its peak in the early 2000s, the UK produced c.4.7 Mmboe/d (million barrels of oil equivalent per day), close to 40% of the total hydrocarbon production in Europe. The next largest European producer was Norway, at 4.2 Mmboe/d. Since then, UK production declined to 1.8 Mmboe/d in 2019, representing c.24% of overall production in Europe, 3% of the OECD countries and 1% of global production, although the UK's share of the global total has marginally increased in the period since 2014, following new discoveries and investment. Scotland's share of the UK's hydrocarbon production has grown from 71% in 2000 to 82% in 2019.

### Historical Oil production

The UK produced c.1.1m barrels of oil equivalent crude per day in 2019, significantly down from its peak production in 1999 (a reduction of c.40%). Almost 95% of the crude and NGL production from the UK is produced from Scotland.

The UK is currently the second largest producer of oil in Europe after Norway. The UK accounted for 38% of European, 12% of OECD and 4% of global oil production in 1999. By 2019, the UK's share in Europe's production was still significant at 33%; however, the UK's relative share of OECD and total global production was down to 4% and 1% respectively.

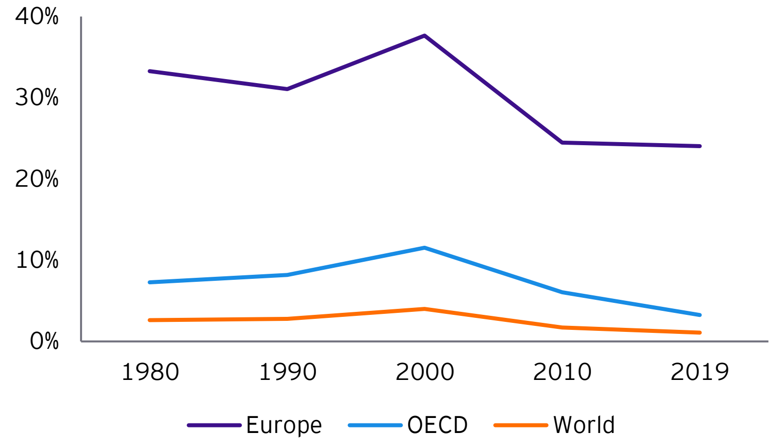
### Historical Gas production

In relation to gas, the UK produced 39.5 bcf (billion cubic feet) of gas in 2019. Similar to oil, current gas production is at roughly 40% of the peak production level in 2002. Scotland contributed c.46% of gas production of the UK in 2000, by 2019 this had increased to 61%.

The UK is the second largest European producer of natural gas behind Norway having overtaken the Netherlands in 2017. The UK accounted for 37% of European, 11% of OECD and 5% of global gas production in 1999; however, by 2019 the UK's share of European production had fallen to 17%. Its contribution to the OECD and global production fell to 3% and 1% respectively.

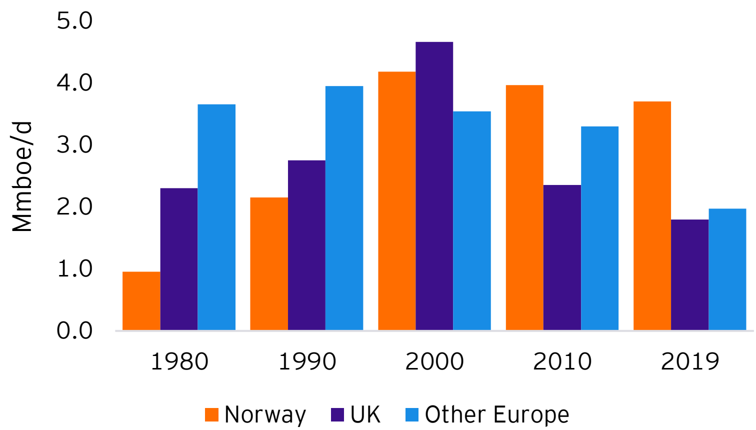
Despite the discovery of new fields, it is expected that both O&G production will continue to decline, given the mature nature of the UKCS basin and the fact that the majority of older fields are reaching the end of their economic lives.

### UK hydrocarbon production as a percentage of total production




Source: BP Statistical Review 2020

### Hydrocarbon Production




Source: BP Statistical Review 2020, NSTA

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### Demand and Supply projection

According to OPEC's World Oil Outlook study, global oil demand is expected to increase from 2020 to 2026 by 13.8 million barrels a day (mb/d). However, almost 80% of this incremental demand is forecast to occur within the first three years (2021-2023), primarily as part of the recovery process from the COVID-19 crisis.

Growth in oil demand is expected to be met by increased production, alongside a resumption of global investment to bolster future O&G supply. As such, non-OPEC countries' oil supply is projected to rise from 62.9mb/d in 2020 to 70.4mb/d in 2026.

As per OPEC's forecast, supply is expected to increase marginally over the next two decades. However, the UN estimates that a 70% fall in production is required over the same period to keep global temperature from rising by more than 1.5 degrees (this is discussed further at Section 12). The chart opposite shows Scottish production against this curve. The ScotNS will not be a significant source of global hydrocarbons over the next 30 years.

As mentioned in the previous page, Scotland produced c.1% of global production in 2020. It is estimated that Scotland O&G production is expected to decline substantially over the next two decades. Further, as discussed in Section 8, exports have declined, both to rUK and ROW, over the last 20 years, mainly due to a decline in production, with ROW exports trajectory impacted more than exports to rUK.

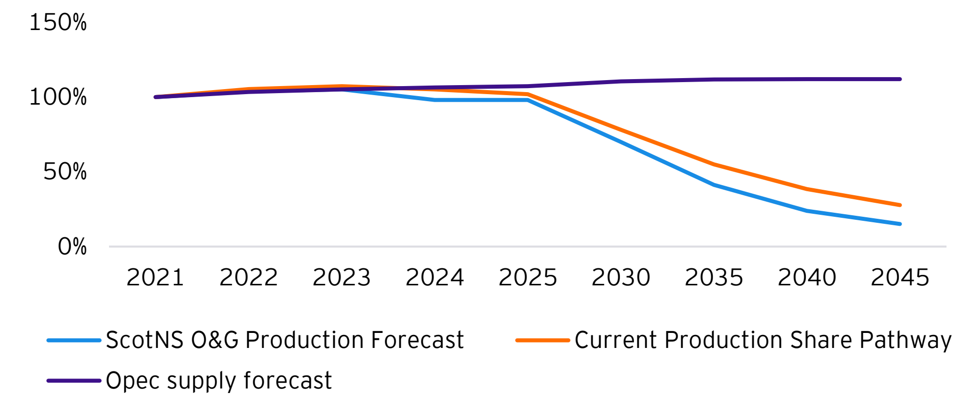
### Future global resources

Our analysis in Section 3 indicates that ScotNS production will continue to decline, with cumulative hydrocarbon production falling by 7.7bn boe by 2050. The chart to the right shows how the combination of declining UK reserves and increasing reserves elsewhere in the world mean that the UK's share of global reserves has fallen. The UK's 1P reserves has fallen from 15.4bn boe in 1980 to 5.9bn boe in 2020.

**Key points**

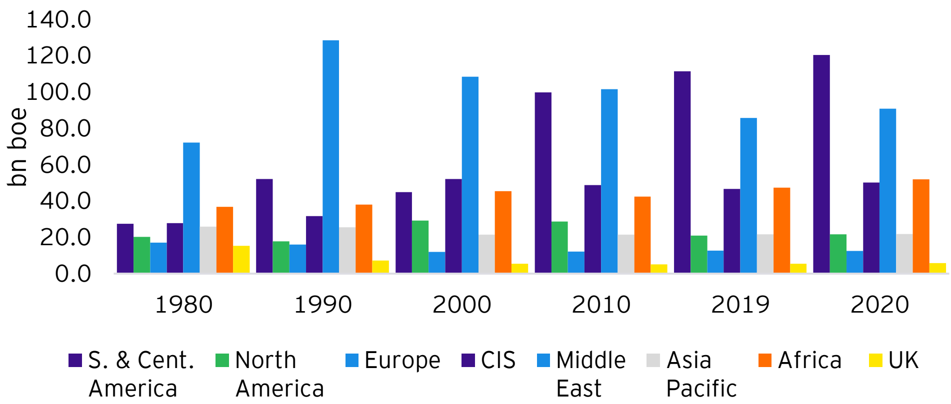
Over the past two decades, Scottish production has substantially declined while world O&G demand has increased. Reserves have also declined, meaning Scotland's position will be less important in future years.

### Production and supply forecast




Source: EY, OPEC

### Reserves to Production years (1P reserves) (2020)




Source: BP Statistical Review 2020

Note: OPEC demand projections are available from 2020 to 2026 and thereafter to 2030

# Scotland in a global context
# Ownership



### Resource and Production ownership

A significant element of the global O&G landscape involves the use of NOC (National Oil Companies) and INOC (International National Oil Companies) and their interaction at a country level.

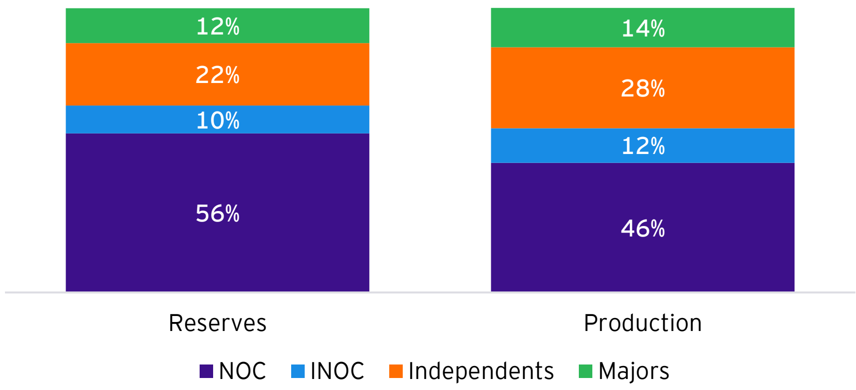
NOC and INOC such as Saudi Aramco in Saudi Arabia, Gazprom in Russia, Equinor in Norway, Qatar Energy in Qatar, etc. together control close to two-thirds of the world's proven-plus-probable (2P) oil reserves and close to 60% of gas reserves. The majority of the reserves in the Middle East and Latin America are held by domestic NOCs, whereas in North America and Europe, the majority are held by private companies (Independents and Majors, or SuperMajors). Similarly, Asian NOCs like CNOOC, Sinopec, Petronas etc. are prominent state owned companies with sizeable production and substantial hydrocarbon ownership in other geographies including the UK.

In addition to holding the largest reserves, NOCs have the lowest average development and production costs. The majority of these reserves are large in size, have a longer plateau and their capital investment requirement is lower for sustaining production.

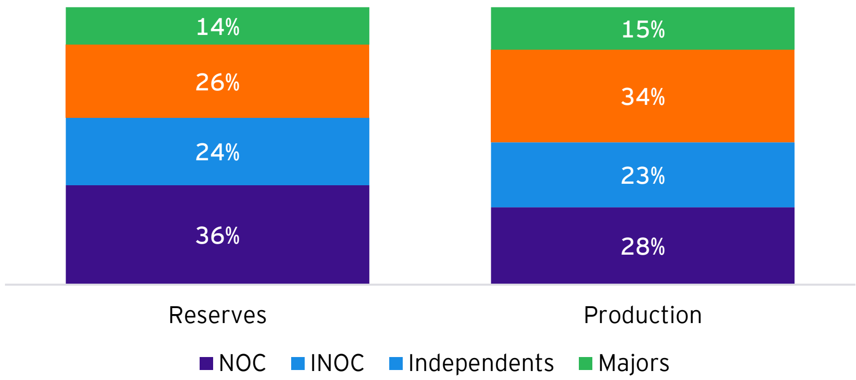
Despite having substantial control of reserves, NOCs often require significant support from Majors and Independents for technical knowhow, prior experience and their ability to manage operations in a cost effective manner.

Due to the risky and complex nature of the O&G exploration and production process, NOCs typically engage with private players to provide investment and create a Joint Venture (JV) through an agreement once a discovery has been made or project has been de-risked. These agreements grant operatorship to the private entity whilst the ownership rests with the government. In a few cases, the Majors have cross-equity holdings in NOCs.

Share of Oil reserves1, Oil production by type of company (2018)




Share of Gas reserves1, Gas production by type of company (2018)




Note 1: 2P - Proven plus probably reserves as per definition for Reserve categories by Society of Petroleum Engineers (SPE)

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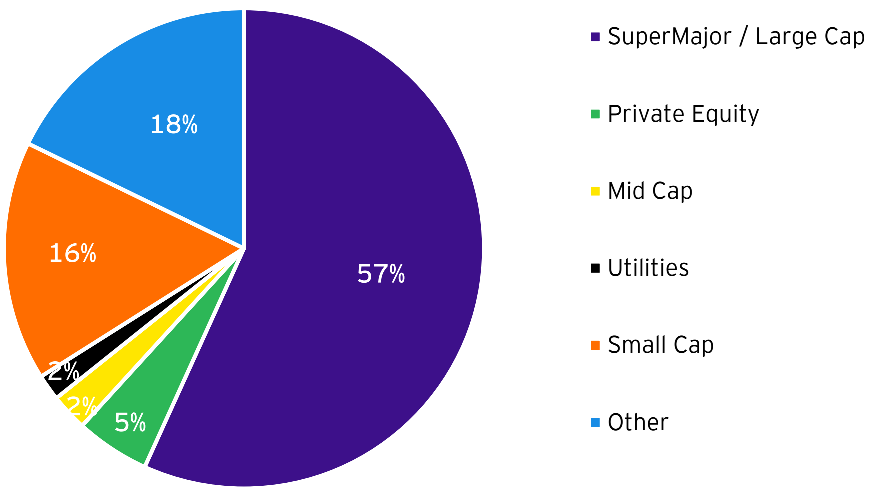
## UK Resource and Production ownership

Unlike the Middle East, Latin America or South East Asia, the UK does not have a domestic NOC. It is home to a more diverse corporate landscape, with several Majors, Independent Exploration and Production (E&P) companies and no single independent organisation having a dominant market position.

Historically, new exploration rounds (generally focussed on existing mature fields) have involved Majors and private equity based E&Ps. Additionally, despite the maturity of the UKCS, it is still considered a very favourable M&A market with several recent transactions taking place, including deals backed by private equity (e.g., Neo Energy, RockRose Energy, Waldorf Petroleum). There have also been some exits during the last few years, with Majors like ConocoPhilips and Chevron exiting the North Sea completely. Similarly some of the major utility players with upstream business like SSE have divested their business as part of their overall business strategy.

**UKCS investor landscape: share of production (Mmboe)**




## Ownership and innovation

Over the years, in terms of technology and innovation, SuperMajors and IOCs have long experience of managing technology development to support both domestic and international operations and hence are preferred partners for NOCs around the globe. These companies are able to build upon their experience gained by operating in multiple geographies and utilize the same in supporting NOCs in the domestic market.

In recent times, NOCs' dependence for technology on Supermajors has reduced as they have grown in size, gained more experience and accumulated the required capital to fund further operations. This experience means that their capability in terms of innovation and technology abilities has increased. Both NOCs and SuperMajors have tended to reduce their use of internal services, relying instead on a broader supply chain to support operations.

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## Investment barriers and drivers – Introduction

In addition to production levels and reserves discussed above, O&G companies consider a wide range of "above ground" factors when making investment decisions. The prevailing legal, fiscal and commercial conditions in a territory, including government involvement via NOCs, as well as oil price have a strong bearing on the profitability of a business. In the remainder of this section we discuss these factors and the UK's position in relation to them.

- **Cost of production** – One of the key considerations when evaluating prospective investments is the cost of extracting the oil from below ground. Different geographies have different geology, basin maturity (including infrastructure), and different type of fields/terrain, which have an important bearing on the cost to explore, develop and produce.
- **Fiscal and contractual terms** – Fiscal terms govern the economic benefit and relationship between government and contractor and determine how financial risk and benefits will be shared. These include corporate income tax, royalty, profit petroleum, signature bonuses, etc.
- **Security and 'above ground risk'** – In a majority of cases, O&G operations are conducted in remote and harsh conditions and the ability to operate securely plays an important role in the decision criteria.
- **Infrastructure and Proximity to market** – Oil as a product is relatively easily transportable and once transported to a nearby port can be shipped to any destination. Conversely, gas tends to require major investment in pipelines or shipping infrastructure for it to be monetized. The presence of local refineries and demand centres is important for supporting profitability.
- **Supply chain** – Oilfield service providers (OFS) play an integral part in the entire O&G value chain. The presence of a strong domestic OFS network provides support to O&G producers as well as helping them in innovation/technological improvements.

Appendix B provides an analysis of opportunities and strengths, key barriers and challenges, of the UK and a selection of other territories, Norway, the United States, Canada, Brazil, Saudi Arabia, Russia and Qatar, to illustrate the factors that an investor will consider. It indicates the range of the different pros and cons that companies need to weigh up as they decide where to invest.

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# Investment barriers and drivers – cost


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## The UK is generally higher cost than other basins

Data from GlobalData allows us to plot global cycle capex and opex costs as a cumulative production curve, with the contribution of each field to global production cumulatively plotted against the cost of production for that field. This shows that the bulk of global production (up to 70%) talks place with lower costs than the majority of UK fields.

Data on global basins are plotted on the chart, with the separate regions of the UKCS plotted separately. This indicates that the full lifecycle costs of UK fields are higher than those of many other countries.

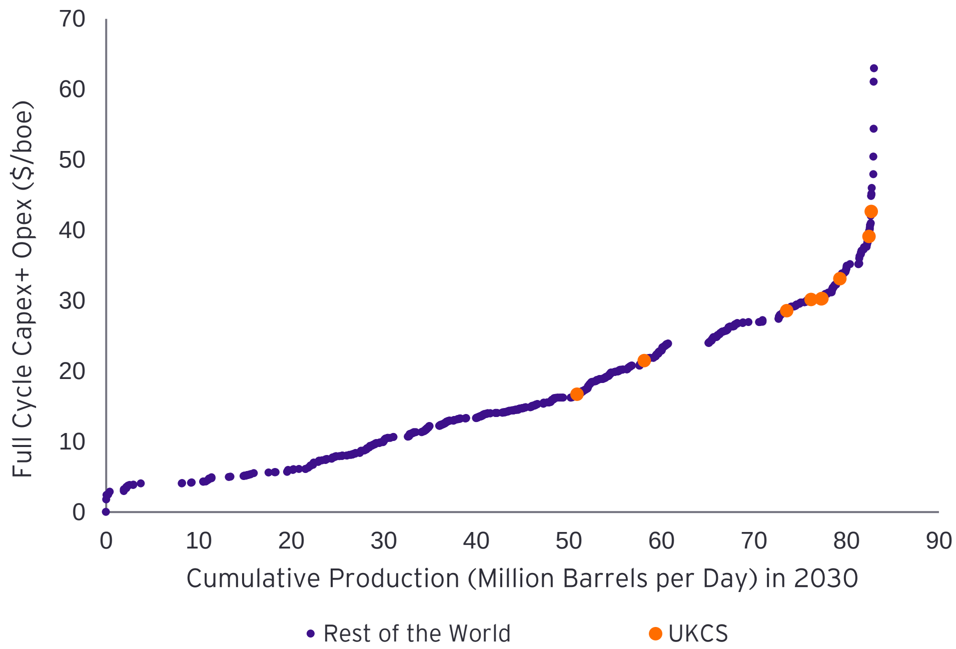
This gives an indicator of the UK's attractiveness from a global market perspective, though it is important to note that there are variations in cost between individual fields, not just between different basins globally. As the chart illustrates, some fields in the UK are lower cost than others, and lower cost than those from some other countries. Additionally, the chart includes onshore basins, which naturally have a lower cost of production, resulting in the UK's offshore basins being further up the curve.

## This affects production in different ways

This analysis presents costs on a whole life basis, whereas production decisions are considered on a marginal basis. In other words, decisions are made on the additional cost of continuing to produce once infrastructure investment has been made, rather than taking account of whole life or full cycle costs (including initial infrastructure expenditure). Decisions regarding production from existing fields would consider different factors from decisions around new fields. For example, existing fields that have already incurred significant capital costs for infrastructure in the past continue to be economically productive as long as the current costs of production are less than the current oil price. However, while data on the marginal costs at different times is not publicly available, due to the interplay of capex, opex and maintenance and replacement timeframes, the chart shows where the UK stands comparatively. Decisions by oil firms will be made on a field basis rather than a basin basis and respond to a dynamic and emerging picture.

Expansion to new fields, where there is additional risk around the productiveness of the field and up front infrastructure costs to defray, means that expanding production in the ScotNS in this way would be financially harder to justify and is likely to occur in fewer cases than previously.

### UKCS vs. Rest of the World cost curve




Source: GlobalData

**Key points**

Expansion to new fields in the UKCS is harder to justify because the infrastructure costs increases the whole life costs, particularly where smaller fields can only be operated for a short time.

# Scotland in a global context
# Investment barriers and drivers – fiscal and contractual



## Investment drivers and barriers

### Fiscal regimes

Global fiscal regimes in relation to O&G are a major consideration for investors as they govern how the financial benefits and risk of operations will be shared. Alongside geology and basin attractiveness, the fiscal regime is a crucial factor in the investment decision and has a fundamental impact on a project's feasibility and economic benefit to the oil company.

Global O&G fiscal regimes differ in number of ways, all of which have a bearing on the attractiveness of investment in production, including:

- **Ownership of mineral resources:** Except in the USA, this is the state
- **Royalty:** Payment to government in lieu of right to extract mineral resources
- **Bonuses:** One-time payment at the time of executing the contract or achievement of a milestone
- **Tax:** Corporation taxes as per the country's prevailing tax code
- **Windfall profit tax:** Special taxes over and above the stipulated income tax as and when profits exceed a threshold
- **Government equity:** Government sometimes retains an option to participate in the field as and when there is a discovery been made
- **Production sharing:** Many contracts entitle the government to a share of the hydrocarbon produced once a proportion of cost has been recovered (government either sells its portion or takes a cash payment from operator in lieu of physical delivery)
- Ring fenced contract: Ability to offset profit/loss across multiple fields from the same geography

### Contractual arrangements

In addition to the taxation regime, the nature of the contracts for O&G extraction used in each country is a crucial factor in the investment making decision. The basic types of contractual arrangements executed in petroleum exploration and production are Concessions and Production Sharing Agreements/Contracts (PSA/PSC). These agreements are concluded between the host country (HC), where the exploration and production operations will take place, and the O&G company (operator).

Modern concession and licensing arrangements are contracts whereby the government grants the investor the exclusive right to exploit natural resources in a given area for a specified period of time, in exchange for payment of royalties, taxation and fees. Under PSA/PSC, the operator is typically rewarded through the recovery of its costs of exploration and production, as well as the right to share in profits from the sale of hydrocarbon.

The key characteristics of Concession and PSA/PSC arrangements are summarised below and provide in detail in Appendix B.

| Parameter | Concession | Production Sharing Agreement/Contract (PSA/PSC) |
|---|---|---|
| Ownership of resources | ▶ State typically owns resources; Operator owns production | ▶ State owns resources/production; Operator remuneration is a share of production hence acquires ownership of that share of oil |
| Revenue source for Government | ▶ Also referred as Tax Royalty Contract/Licence<br>▶ Typically consist of Royalty (as % of revenue, paid in kind/cash)<br>▶ Corporate Income Tax on profits<br>▶ Additional tax/special petroleum tax (if applicable) | ▶ May consist of Royalty (as % of revenue, paid in kind/cash)<br>▶ Typically includes share in profit (post cost or percentage thereof have been recovered by Operator)<br>▶ Corporate income tax on profit<br>▶ Additional tax/special petroleum tax (if applicable) |
| Recovery of cost | ▶ There is no recovery of Operator's cost and taxes | ▶ Cost Oil/Gas – the fiscal terms typically grant a mechanism for operator to recover costs (exploration, development, operation, abandonment) from Gross Revenue before sharing of profit |
| Operator revenue | ▶ Gross production less Royalty | ▶ Cost Oil/Gas + Profit Oil/Gas (profit available after cost have been recovered, share in profit shared with government) |
| Ownership of the facilities | ▶ Held by the company | ▶ Held by the state/government |
| State Participation | ▶ State/government typically does not participate in the operations | ▶ State/government reserves a right to participate when the project is de-risked |

# Scotland in a global context
# Investment barriers and drivers – fiscal and contractual (cont'd)



## The UK fiscal position

The key legislation governing the development of hydrocarbons in the UK is the Petroleum Act 1998, which vests the mineral rights in the Crown.

The UK's current fiscal regime has been altered to make it simple and attractive for investment. Comparisons with other regimes are overleaf and further detail is given on other regimes in Appendix C. The taxation regime that applies to profit derived from UK O&G production is made up of two key components:

- Ring Fence Corporate Tax (RFCT): Although the main corporate income tax rate is 19% (increasing to 25%), the RFCT applicable to upstream O&G companies remains at 30%.
- Supplementary charge: Supplementary Charge (SC) applies to ring fenced profits accruing from 17 April 2002. The current rate of SC is 10%.

The tax regime offers operators tax reliefs which can be counted against profits, including immediate 100% relief for most capital expenditure, and trading losses that carried forward can be uplifted by 10% for up to maximum of 10 periods. In addition, the tax system is used to contribute to the funding of decommissioning. This means that in particular years oil firms can pay no tax or receive a rebate despite making a profit.

In order to attract investment in the sector, in recent years the UK Government has made significant changes in the regime, including:

- Abolition of Petroleum Revenue Tax (PRT) – A field-based tax charged on profits arising from O&G production from individual fields which were given development consent before 16 March 1993; at the time of introduction, the PRT was 75%, it was subsequently reduced to 50% and then to 0% in January 2016.
- Reduction in SC tax rate – SC was reduced from 20% to 10% in 2016.
- Introduction of Investment Allowance in 2016 which replaced and unified the Field Allowance, introduced in 2009, and provides additional relief for expenditure incurred.

The overhaul of the UK's concession-based O&G fiscal regime, including the above changes to the allowances/reductions, was designed to incentivise operators to maintain or enhance their investment in the UKC, despite the fact that the UKCS basin has a declining future production forecast.

As a result of these changes, the UK has an attractive concession regime, especially compared to other significant O&G producing nations and European producing nations. Thus, when firms are allocating investment capital among different jurisdictions where they operate, these factors will be positive for the UK.

# Scotland in a global context
# Investment barriers and drivers – fiscal and contractual (cont'd)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## Average Government Take, Breakeven and NPV per barrel

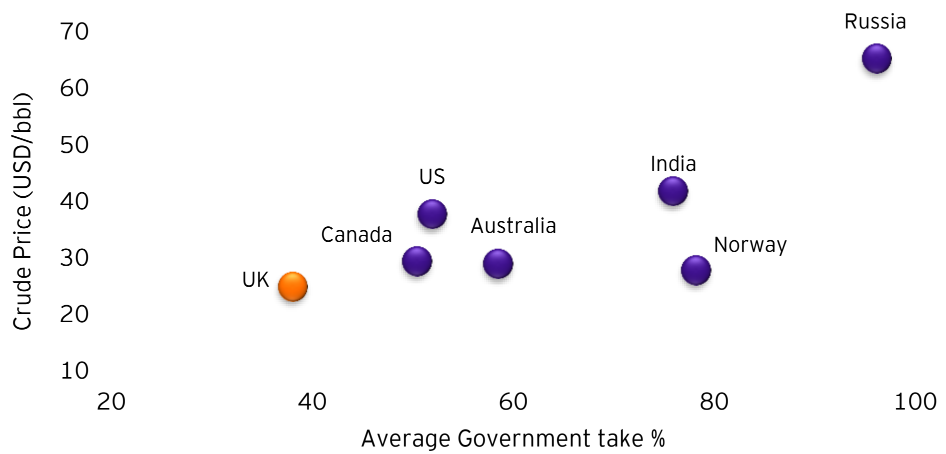
Fiscal terms play an important role in the investment decision making process for operators and are equally important for governments looking to maximise their share of income whilst ensuring active participation and interest in investment by private players. The fiscal regime structure is significantly influenced by the resource richness of the nation, in that countries with large potential can have more stringent fiscal terms and higher government take as this is compensated by the large resource pool. The Net Present Value (NPV) per boe, total NPV or Internal Rate of Return (IRR) are a few of the important financial metrics which individual operators consider while evaluating and comparing projects for investment analysis.

Rystad Energy published a report in January 2021 that assessed the attractiveness of the development of offshore fields across various countries. This fields were examined as they had similar capital costs, production and operating costs.

The report showed that, due to the attractive fiscal regime, the UK offers operators the best profits conditions to develop offshore fields. Additionally, the UK offered the highest post-tax valuation and the best profitability conditions for operators, with a NPV of $11.1 per boe in the country assuming a flat oil price of USD 70 per barrel.

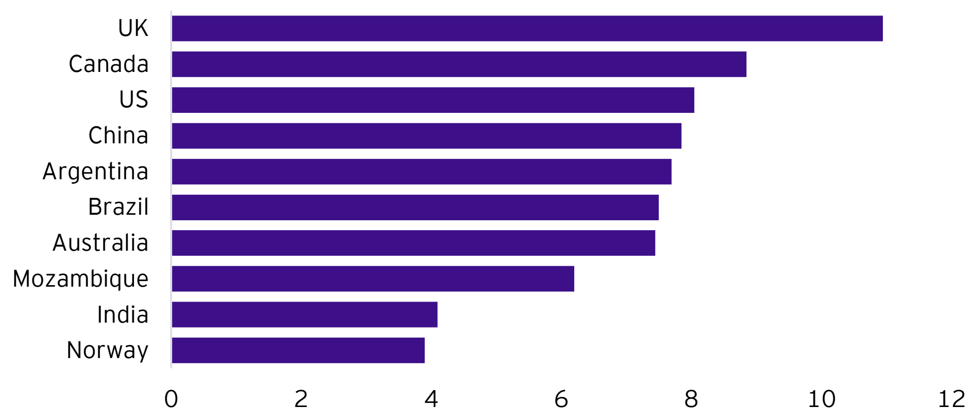
Similarly, the break even prices for projects were found to be lowest in the UK as the country benefits from only net taxes and a very simple fiscal structure (Corporate Tax, Supplementary Charges). Further, the overall government take in the UK is one of the lowest among the countries considered. This is in part because the UK regime was adapted to the higher costs of UK production and because of the changes to the fiscal regime discussed previously.

### Average government take and implied break even price per barrel




Source: Rystad Energy
Note: We have taken approximate figures

### NPV (USD per boe)




Source: Rystad Energy

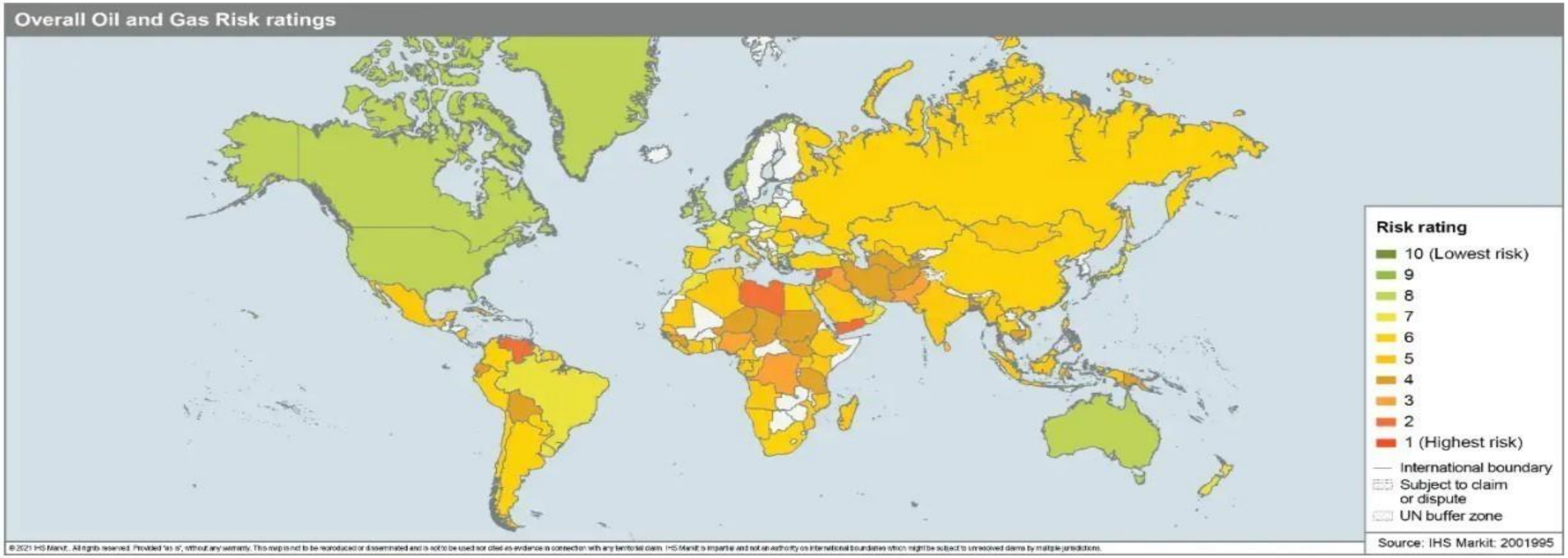
# Scotland in a global context
# Investment barriers and drivers – security and above ground risk

## Above Ground Risk

"Above Ground" factors make the North Sea a relatively attractive location for the O&G industry. These include stability of government, regulatory and contractual environments, the fiscal regime and its impact on return on investment, proximity to established markets, cost of extraction and the standard of the supply chain.

A key advantage possessed by the UK is its international reputation as a mature and stable place to extract O&G. With an established rule of law, regulatory regime, fiscal regime and active capital markets, the UK North Sea is seen as stable and predictable, one of the lowest risk places to conduct O&G business, and therefore a source of attractive "safe" reserves for companies' investor propositions. This is reflected in IHS Markit's 2021 above ground risk assessment, which ranked the UK as one of the lowest risk countries.

However, the risk rating does not necessarily determine investment. An international investor may view a riskier location as offering the potential for a level of return on investment that justifies the additional risk. Prospective levels of returns may also make the prevailing fiscal and contractual requirements in a location, such as contracting with the territory's NOC as considered on the following page, relatively attractive, despite the additional risk.




Source: IHS Markit

# Scotland in a global context Investment barriers and drivers



### Scottish proximity to establish markets and infrastructure

Another important 'above ground' dynamic of the UKCS is its proximity to an established demand source. In Sections 7-11, we explored the Scottish inflow and outflow of O&G products and the downstream infrastructure.

The refinery at Grangemouth plays a leading role in supplying Scotland's fuel demand, and is of strategic importance to Scotland's energy supply and regional economic development.

O&G producing basins that have an established market and have the security of local demand are a more attractive proposition than a remote greenfield project. These factors help to de-risk the investment and the presence of a local market can also reduce costs.

### Offshore O&G Supply Chain

The UK also has a world class O&G supply chain. The North Sea is a complex operating environment and the skills and technologies developed from operations in the UKCS have been valued in other offshore basins around the world.

In 2019 the value of supply chain exports was put at £12.7bn (EY Oilfield service report 2020). Our analysis in Section 4 shows that the ScotNS contributes over 79,000 jobs and contributes £17.9bn of GVA to the economy. The contribution of the O&G sector to the Scottish economy is dynamic and changes over time. For instance, between 2000 and 2019, O&G production levels in Scotland reduced by 56% in value whilst Scottish GDP levels more than doubled, principally as a result of declining O&G reserves.

Having access to a skilled workforce and a supply chain that is capable of supporting operations is a major incentive for investment, and the established nature of these in the UK make investment in the ScotNS attractive.

### Conclusion

The UKCS has been an important contributor to the global O&G industry since the 1960s, with significant production, and an influential supply chain involved in numerous projects. Despite production peaking in the early 2000s, the UKCS continues to attract investors. However, with falling production levels and limited future prospective resources, its role as a global O&G producing basin is expected to diminish.

Oil firms who have a large diverse portfolio follow a rigorous capital allocation process filtering opportunities across globe.  When considering investment in new fields, the UK's geology makes exploiting the remaining reserves more challenging and higher risk. Global costs of production present a complex picture, but the cost of production in the UK is higher than other global basins.

Despite this reduced production potential, and cost pressures, there are a range of "above ground" considerations that mean Scotland remains attractive to investors. These factors include:

- The UK has a stable fiscal regime and a investor friendly environment that continues to offer attractive conditions to investors.  Assume parity on costs, the fiscal regime more generous than other jurisdictions.
- The commercial and regulatory environment allow for strong returns on investment in Scotland.
- The ScotNS's proximity to established European demand sources and a sophisticated infrastructure landscape make it attractive to investors.
- Access to a world class supply chain is available.

The result of these conflicting forces is that the ScotNS has seen continued extraction but a slowdown in investment reflecting the reserves/risk position, which we see reflected in the production forecast.

**Key points**

Despite a relatively low level of reserves, the UKCS is still profitable and a very secure location for O&G extraction compared to other basins and in particular compared to other offshore basins.

# 13 Scottish Production pathways

# Global production pathways and carbon budgets

## Introduction

This section develops a global O&G production pathway consistent with the goals of the Paris Agreement. We focus on the 1.5°C carbon budget, but we include a less than 2°C scenario for comparison. We use the global scenarios to project what this means for Scotland under different emissions reduction criteria.

## Global production pathways and the stages of the Energy Transition

Global production pathways are multifaceted and the process of energy transition has multiple stages, each of which takes time. Alternative energy technologies will fall in cost over time, consumers and power system operators will gradually accept those technologies, government regulations will come into force and existing production and consumption infrastructure will age and fall away.

Our analysis adopts the methodology established by EY's Fuelling the Future (FtF) modelling framework. This captures all of those effects and allows us to examine the assumptions we need to make about how the various factors that drive those processes will unfold.

## 1.5°C carbon budget

The goal of the Paris Agreement is to limit the increase in global temperatures to 1.5°C relative to pre-industrial levels. The starting point for determining a global pathway to 1.5°C is to understand the cumulative amount of carbon dioxide that can be emitted into the atmosphere to achieve this goal.

We have adopted a position consistent with the Intergovernmental Panel on Climate Change (IPCC) AR6 WG1, and endorsed in WG3. We will consider the following scenario:

1. A **500Gt$CO_2$** carbon budget that will limit warming 1.5°C. This is based on the 50% likelihood of meeting this goal.

The carbon budget commenced from 1 January 2020 and assumes that the carbon budget will be utilised by 2050. Our probability assessment of meeting the 1.5°C goal is consistent with the CCC who state "we interpret pathways with at least a 50% chance of limiting peak warming to 1.5°C as consistent with a global ambition of limiting the temperature increase to 1.5°C."

We have introduced our global production pathway and the key assumptions overleaf.

## Stages of the energy transition

| 1 | 2 | 3 | 4 |
|---|---|---|---|
| Alternative technologies become competitive | Consumers accept new technologies | Government regulation | Infrastructure wears out and is replaced |

## 9 demand areas of the FtF model

| | | |
|---|---|---|
| Road Transportation (passenger) | Road Transportation (cargo) | Waterborne Transportation |
| Aviation | Rail | Residential |
| Commercial | Industrial | Petrochemicals |

# Global pathway scenario assumptions



## Fueling the Future scenarios

Using the FtF tool we have modelled a scenario for the pace of energy transition, demonstrating the significant steps that are needed in terms of technology adoption to meet Paris targets.

The 1.5°C Pathway is consistent with meeting the goals of the Paris Agreement in limiting global temperature rises to 1.5°C. This scenario assumes that alternative energy becomes cheap enough quickly enough to displace existing infrastructure. Climate change becomes a top priority for governments and consumers around the world.

## FtF approach

Typically a model starts with a set of assumptions based on expectations of key factors such as prices, economic growth and consumer behaviour. This can be used to predict consumption of fossil fuels over time.

However, the approach that we use with FtF is to start from a target $CO_2$ based on carbon budgets and then to understand what assumptions need to hold true to limit $CO_2$ emissions to the defined level; i.e., the FtF tool constrains the various energy production pathways to follow the UN scenarios as closely as possible. Through this process we are also able to understand, in our view, the most credible mix of market assumptions taking into account technological adoption rates and price trends.

In reality there are an infinite amount of scenarios that could result in a given $CO_2$ output. The tool enables policy makers to understand what credible mix of market assumptions may achieve a given carbon budget, how different these market assumptions may be from the current reality, and the key trade offs when developing policy. This is something which is not possible by using publicly available fossil fuel consumptions forecasts such as those from the IEA or UN. However, the model's assumptions regarding the future fuel mix are impacted by the production pathways (and the assumptions that underpin them) and may not mirror publicly available fuel forecast scenarios.

## Assumptions and impact

Table 13 shows some of the key assumptions that underpin the scenario. The factors primarily driving the speed of transition are the carbon price, the EV market share and the renewables market share.

The 1.5°C Pathway is achieved by using aggressive assumptions across all key factors for the entire analysis period. The 1.5°C Pathway assumptions represent what is required to deliver a Paris-compliant outcome and do not reflect the current reality in terms of technology adoption; furthermore, there remains significant uncertainty about how quickly the energy transition will be adopted globally.

An advantage of the FtF approach is that it allows users to explore the key factors that impact the production pathways. For example, it provides users with a trajectory that forecasts EV market share and compare this trajectory to alternative EV evidence.

### Table 13: Fuelling the Future scenario – representative current assumptions

| | 1.5°C Pathway |
|---|---|
| Carbon Price (2030) /tonne | $200 |
| Consumer uptake in the EV Market | Very high |
| Level of support for renewable energy in the market | High |
| ICE Vehicle Attrition | 15.0% |
| Coal Power Plant Attrition | 11.0% |
| EV Cost Reduction | -2.1% |
| Solar Cost Reduction | -2.7% |
| Wind Cost Reduction | -0.8% |

Source: EY FtF model

# Global production pathway results

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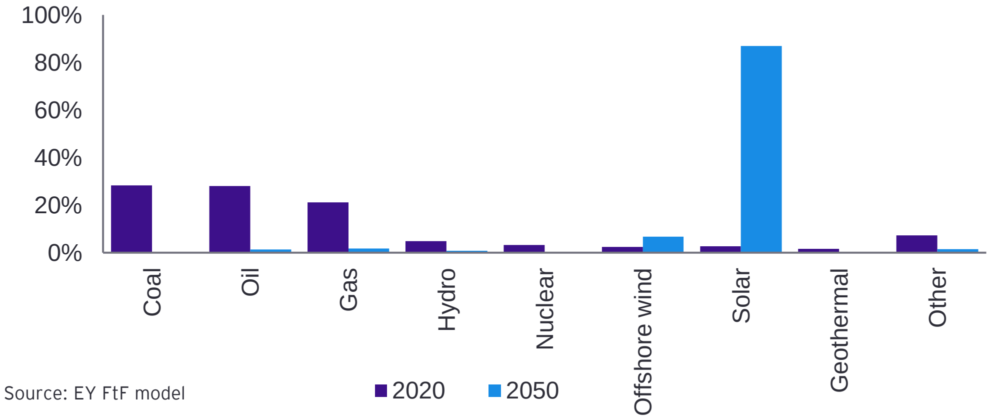
## Global production pathway results

It is important to stress the inherent uncertainty with modelling future fossil fuel demand. This is illustrated by the wide variety of oil demand scenarios published by O&G producers, with 2050 demand ranging from 24 million barrels per day in the BP 'Net Zero' scenario to 106 million barrels per day in the Shell 'Waves' scenario. This is further complicated by the need to forecast both demand and the energy mix, with predications on coal attrition having significant implications for oil and natural gas demand (higher coal attrition facilitates a more gradual decline in both O&G).

On the following graphs we have shown the results of our scenario for oil and natural gas. As expected, meeting the Paris 1.5°C target requires a steep decline in all fossil fuels. Targeting 1.5°C requires an almost immediate reduction in demand across all fuel sources. Whilst we acknowledge that other Paris-compliant pathways can be developed, any delay or deceleration in the rate of transition would result in a greater overall environmental impact.

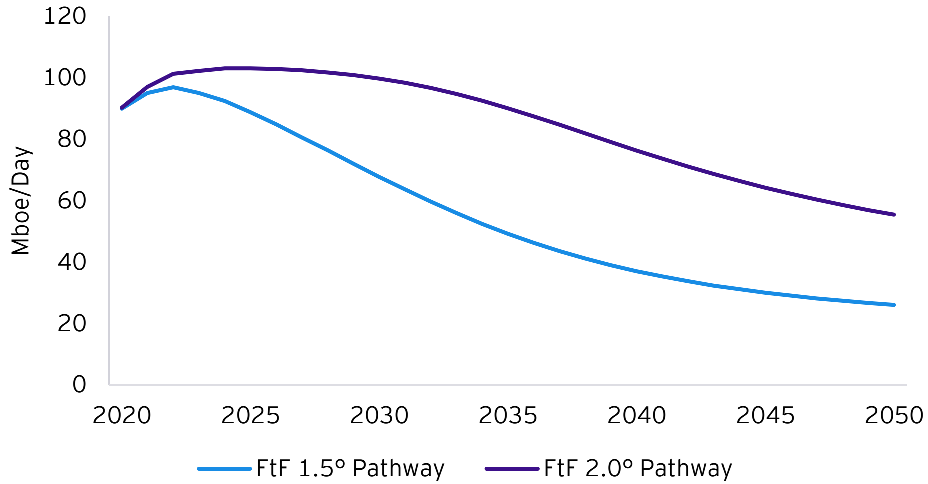
Our analysis also shows the 2050 global fuel mix must include a large proportion of solar, which replaces the coal, oil and gas in the 2020 position. The 2050 Scottish fuel mix is likely to differ from this position, with significantly lower levels of solar and a higher proportion of wind. This is explored further in future phases of this work. The individual fuel mix of every country (including Scotland) will differ and will be highly dependent on a range of factors including local geography. Our analysis assumes that costs of solar are expected to fall at a higher rate than the costs of wind power, hence why solar represents a larger share of the global mix.

### 2020 versus 2050 fuel mix (1.5° scenario)



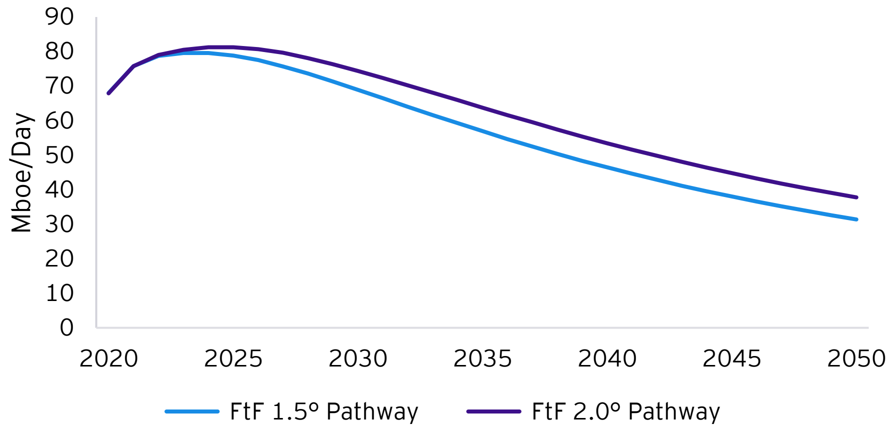

Source: EY FtF model

### Global oil demand




Source: EY FtF model

### Global natural gas demand




Source: EY FtF model

# Global production pathway comparison to UN benchmarks

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## Comparison to UN benchmarks

To provide a benchmark for the "1.5°C Pathway", we have compared our scenario against the UN Production Gap Report (PGR) estimates and the IEA's Sustainable Development pathway and the Net Zero Emissions pathway. Opposite we have shown how our projection compares to PGR forecasts for both 1.5°C and 2°C targets and both IEA scenarios. The PGR projections are based on the IPCC's 2018 Special Report carbon budget of 580Gt of $CO_2$ for 1.5°C and 1,170Gt of $CO_2$ for 2°C. Our analysis is based on IPCC AR6 WG1 50% likelihood for 1.5°C – this corresponds to a carbon budget of 500 $GtCO_2$ for the 1.5°C Pathway. The IEA's Net Zero Emissions scenario is the pathway for the global energy sector to achieve net zero $CO_2$ emissions by 2050. The is consistent with limiting the global temperature rise to 1.5 °C (with a 50% probability). The Sustainable Development is consistent with limiting the global temperature rise to 1.65°C (with a 50% probability).

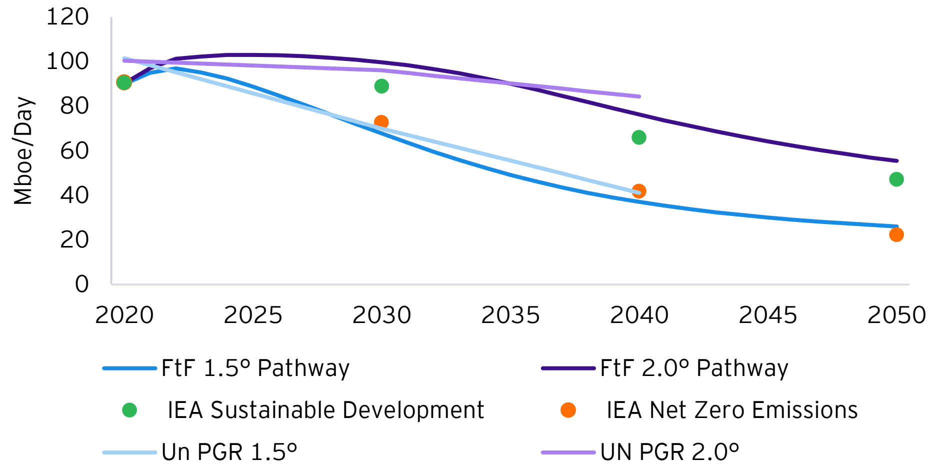
The PGR scenarios only run until 2040 and it is not clear what assumptions the UN has made about oil, natural gas and coal demand after that period. Additionally, the UN report does not provide detail on the drivers of EV and renewable energy or the rate at which fossil-fired assets decay that would be necessary to make direct comparison possible. We have calculated the cumulative carbon emissions (through 2040): the PGR 1.5°C scenario results in cumulative emissions of 495Gt (very close to the 1.5°C Pathway result) and the PGR 2.0°C scenario results in cumulative emissions of 640Gt against an overall budget of 1170Gt. This explains in large part the gap between the our estimate and UN estimates of Paris-compliant fossil fuel demand.

Between the UN, IEA and the FtF there are small differences in production pathways. This is to be expected from a range of complex models with a different drivers and assumptions. However, we are confident that the FtF pathways represent appropriate scenarios based on the comparisons set out in this analysis.

The PGR scenarios do not reflect the impact of COVID-19 on oil demand and therefore have a higher output in 2020.

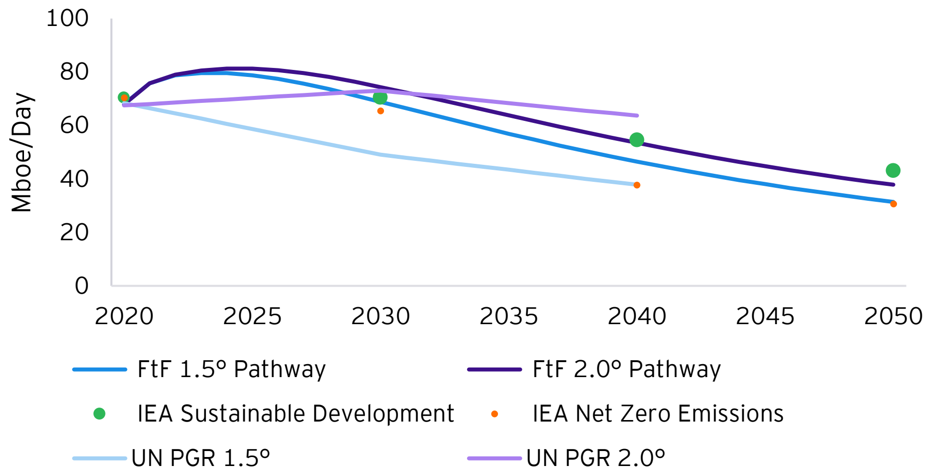
**The UN trajectories assume rapid progress in reducing O&G demand is made (potentially through technology) after 2040 in order to ensure global temperature increases are below 1.5ºC/2ºC.**

### Global oil demand




Source: EY FtF model

### Global natural gas demand




Source: EY FtF model

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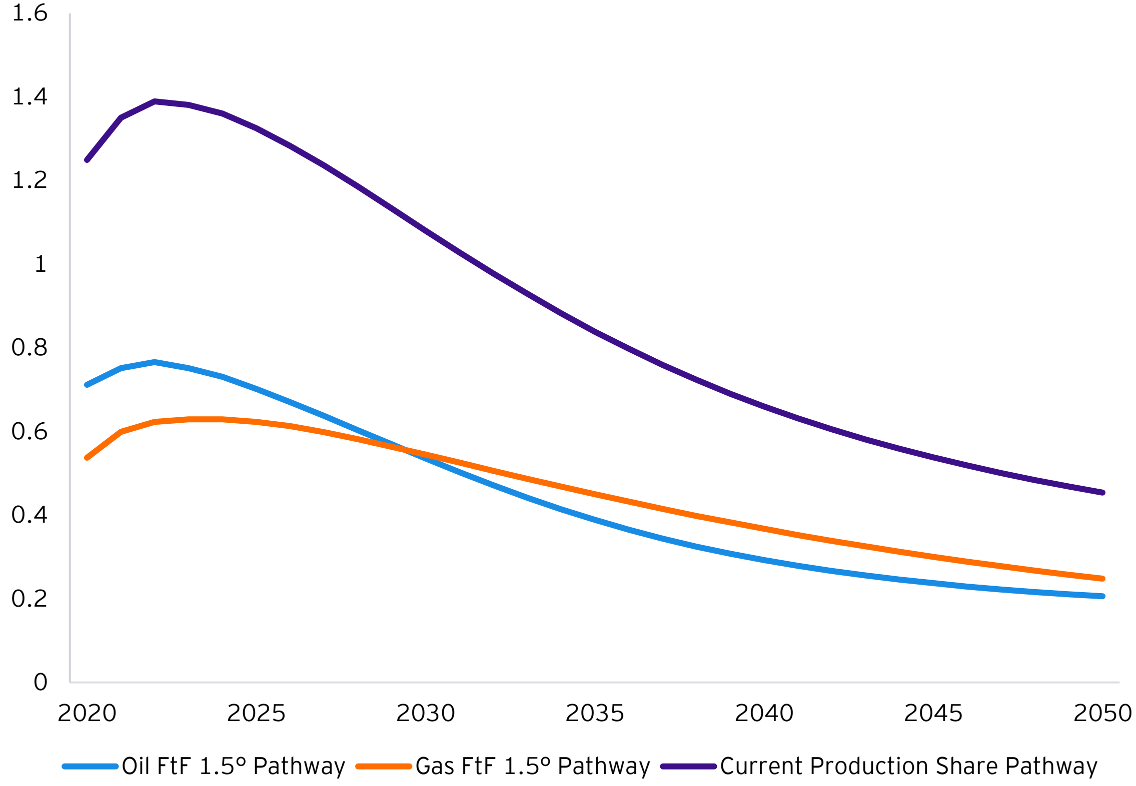
## Current Production Share Pathway

The figure on the right shows Scotland's share of the global FtF production scenario. This combines the separate O&G pathways explored on the previous pages. The Scottish FtF modelled scenario was arrived at by assuming that Scotland's production serves a constant portion of global demand, but we note that alternative outcomes may arise given the many other factors in play including oil prices, cost and regulation. The current production share pathway is just one of many potential pathways that SG could choose. These have been explored in the remainder of this section.

Assuming no further exploration or discoveries, natural decline of North Sea resources will result in the production forecast being below the Current Production Share Pathway.

In reality Scotland's production will differ from forecasts based on trajectories for supply and demand at global level. Additionally, the pace of energy transition will be uneven compared to other countries and as a result, there are different ways that Scotland could explore how O&G production aligns with its Energy Strategy and Just Transition plans.

**FtF Current production share pathway for Scotland**




Source: EY FtF model

# Just Transition scenarios – methodology and approach



## Introduction

This section of the report explores the range of potential Just Transition scenarios and how they all lead to very different potential pathways for the Scottish O&G sector, while highlighting what the Just Transition could involve for Scotland and its people. We have set out below a definition of each scenario, a methodology for how each scenario has been calculated, and any assumptions or limitations of our approach and the data sets available. Noting that these scenarios are likely to be refined, we have also documented our initial outputs from the analysis and suggested some potential impacts that should be explored in later phases of work to inform policy.

## Approach

We have calculated a percentage adjustment to the Current Production Share Pathway (a "factor") for each scenario by comparing the performance of Scotland (based on UK where data was unavailable) against other O&G producing countries. We have focused on O&G producing countries because the purpose of this analysis is to understand how Scotland's O&G sector could decline relative to other O&G producing basins. Our analysis includes O&G producing countries that contributed more than 0.5% of global O&G production in 2019 as per the BP Statistical Review of World Energy. We then adjust the Current Production Share Pathway rate of decline by the factor. This methodology should not be taken to imply that the Current Production Share Pathway is in any way preferred to the other scenarios presented below.

| | Scenario | Definition | Methodology | Assumptions/limitations | Data set |
|---|---|---|---|---|---|
| 1 | **Comparative carbon intensity of production** | To minimise the environmental impact of O&G production, extraction should decline at a faster rate in areas that have a higher carbon intensity of production | ▸ Obtain an emissions factor (how much greenhouse gas is omitted per unit) for O&G producing nations<br>▸ Calculate the weighted average carbon emissions intensity of production across nations<br>▸ Compare UK carbon intensity to the weighted average, calculating in percentage terms how UK carbon intensity compares to the weighted average<br>▸ Adjust the Current Production Share Pathway rate of decline by this percentage | ▸ UK carbon intensity aligns with ScotNS carbon intensity<br>▸ Oil carbon intensity is a reasonable proxy for O&G carbon intensity<br>▸ Does not take into consideration how variable carbon intensity of production could be within each country or transportation emissions<br>▸ Current carbon intensity gives a reasonable expectation of future carbon intensity (does not account for national plans or deals to improve carbon intensity of production, e.g., NSTD) | ▸ Carbon intensity of crude oil production (measured in $gCO_2eq/MJ$) from journal supplementary materials Global carbon intensity of crude oil production (science.org) |
| 2 | **Historical emissions caused (North Sea production/global production)** | Countries that have produced greater quantities of O&G have made a greater contribution to emissions and have extracted more economic benefits. Production should therefore decline at a faster rate. | ▸ Obtain estimates of historical O&G production by country<br>▸ Apply emissions factor estimates to production volumes to calculate historical emissions caused by production<br>▸ Using 2020 population estimates, calculate historical emissions from production per capita<br>▸ Calculate the average historical emissions caused per capita across producing countries<br>▸ Calculate a factor by comparing UK historical emissions caused per capita to the global average,<br>▸ Adjust the Current Production Share Pathway rate of decline by this percentage | ▸ Takes UK historical emissions per capita as the basis for the ScotNS- given that ScotNS O&G has been treated as a UK resource, the benefits have not been exclusively held within Scotland<br>▸ Does not consider emissions from production<br>▸ O&G extracted has a uniform emissions intensity irrespective of location | ▸ Production data per country taken from Our World in Data: https://ourworldindata.org/fossil-fuels which uses BP Statistical Review of World Energy<br>▸ Emissions factors taken from Our World in Data: https://ourworldindata.org/fossil-fuels which uses Intergovernmental Panel on Climate Change (IPCC) emissions factors |

# Just Transition scenarios – methodology and approach (cont'd)



| Scenario | Definition | Methodology | Assumptions/limitations | Data set |
|---|---|---|---|---|
| 3 **Historical emissions (UK wide)** | Nations that have contributed a greater amount to historical global carbon emissions should transition at a faster rate | ▸ Obtain data on historical $CO_2$ emissions for O&G producing countries and calculate historical emissions per capita<br>▸ Calculate an average historical $CO_2$ emissions per capita for O&G producing nations<br>▸ Compare historical UK emissions per capita to the average across O&G producing nations, calculating in percentage terms how UK historical $CO_2$ emissions per capita compare to the average<br>▸ Adjust the Current Production Share Pathway rate of decline by this percentage | ▸ UK emissions per capita are comparable to Scotland's emissions per capita<br>▸ All carbon emissions are of equal importance, therefore there is no weighting towards historical or recent emissions<br>▸ $CO_2$ emissions are measured on the basis of production<br>▸ $CO_2$ emissions are from fossil fuel use and do not consider land use (e.g. impacts of deforestation) | ▸ The Global Carbon Project fossil fuel emissions data accessed through Our World in Data: https://ourworldindata.org/fossil-fuels<br>▸ Our World in Data historical emissions data covers period from 1750 to 2019.<br>▸ Population data taken from UN World Population Prospects 2019: https://population.un.org/wpp/Download/Standard/Population/ |
| 4 **Current emissions on per capita basis** | Nations that have higher emissions per capita should transition at a faster rate | ▸ Obtain data on $CO_2$ emissions for O&G producing countries and calculate emissions per capita<br>▸ Calculate an average current $CO_2$ emissions per capita for O&G producing nations<br>▸ Calculate UK $CO_2$ emissions per capita, apply an adjustment to this figure using ONS regional $CO_2$ emissions data to estimate Scotland $CO_2$ emissions per capita<br>▸ Compare Scotland $CO_2$ emissions per capita to the average across O&G producing nations, calculating in percentage terms how Scotland emissions per capita compare to the average<br>▸ Adjust the Current Production Share Pathway rate of decline by this percentage | ▸ $CO_2$ emissions are measured on the basis of 'production'<br>▸ $CO_2$ emissions are from fossil fuel use, including coal, and do not consider land use change (e.g. impacts of deforestation) | ▸ The Global Carbon Project fossil fuel emissions data accessed through Our World in Data: https://ourworldindata.org/fossil-fuels<br>▸ 2019 emissions have been used as the basis for current emissions.<br>▸ Population data taken from UN World Population Prospects 2019: https://population.un.org/wpp/Download/Standard/Population/<br>▸ Scotland $CO_2$ emissions per capita, calculated by adjusting UK $CO_2$ emissions per capita using ONS 2019 regional emissions data: https://data.gov.uk/dataset/723c243d-2f1a-4d27-8b61-cdb93e5b10ff/uk-local-authority-and-regional-carbon-dioxide-emissions-national-statistics-2005-to-2019 |
| 5 **Comparative affordability for producing countries** | Countries that are more able to afford to transition from fossil fuels should transition at a faster rate | ▸ Obtain GDP per capita for O&G producing nations<br>▸ Calculate the average GDP per capita for O&G producing nations<br>▸ Adjust UK to Scotland figures by multiplying UK GDP per capita by the ratio of Scottish to UK GDP per capita, calculated using ONS data (Scotland GDP per capita/UK GDP per capita),<br>▸ Compare Scottish GDP per capita to the average across O&G producing nations, calculating in percentage terms how UK GDP per capita compares to the average<br>▸ Adjust the Current Production Share Pathway rate of decline by this percentage | ▸ GDP per capita is a reasonable basis for assessing different nations' ability to transition from fossil fuels<br>▸ Does not take into account how dependent a country might be on O&G and how diversified an economy might be. Further work is required to incorporate reliance on O&G into the affordability scenario. | ▸ World Bank GDP per capita for 2019: https://data.worldbank.org/indicator/NY.GDP.PCAP.KD.ZG?locations=1W<br>▸ Population data taken from UN World Population Prospects 2019: https://population.un.org/wpp/Download/Standard/Population/<br>▸ UK GDP per capita adjusted to Scotland GDP per capita by multiplying by the ratio of Scottish to UK GDP taken from ONS 2019 regional economic data: https://www.ons.gov.uk/economy/grossdomesticproductgdp/bulletins/regionaleconomicactivitybygrossdomesticproductuk/1998to2019 |

# Just Transition scenario results

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## Scenario results

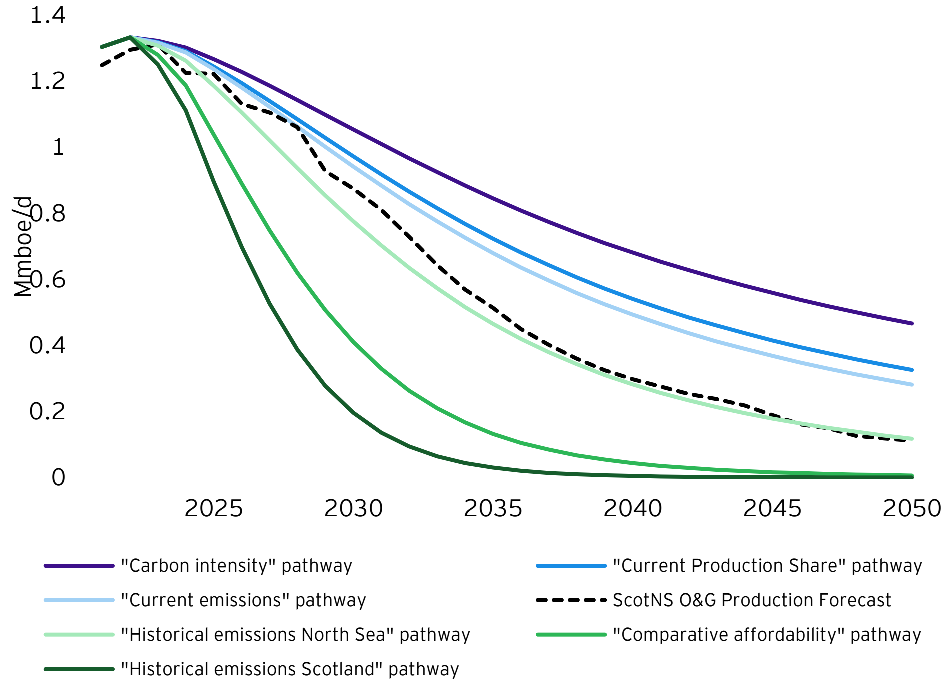
The table below shows the factors we have calculated for each scenario and gives a summary of what is driving the numbers. A factor which is greater than 100% accelerates the rate of decline in production.

| Scenario | Factor | Definition |
|---|---|---|
| Historical emissions (UK wide) | 544% | ▶ The UK has the fourth highest cumulative emissions, and second highest historical emissions per capita, of all the O&G producing countries |
| Comparative affordability for producing countries | 352% | ▶ The UK has the seventh highest GDP per capita of the O&G producing countries<br>▶ Scotland's 2019 GDP per capita was 7% below the UK average |
| Historical emissions caused (North Sea production/global production) | 169% | ▶ Big differences across countries, with Middle Eastern countries typically having high levels of production relative to population size<br>▶ Global average is brought down by high population countries that are relatively modest producers of O&G such as China, India, Egypt and Indonesia |
| Current emissions on per capita basis | 110% | ▶ The UK's 2019 emissions per capita match the average for O&G producing countries<br>▶ Scotland's 2019 per capita emissions were 10% higher than the UK average<br>▶ Middle Eastern countries tend to have the highest 2019 emissions per capita, with India, Angola and Nigeria having the lowest |
| Comparative carbon intensity of production | 75% | ▶ UK O&G production emissions are more regulated than a number of other O&G producing countries<br>▶ North American production and North African producing countries typically had a higher carbon intensity which raises the global average |

Whilst these factors will require further refinement with the potential to add further complexity into the calculations, it highlights that setting a Just Transition on a global level will be challenging and require judgement as to what represents an appropriate basis for adjusting production pathways.

The chart below shows each of the production pathway scenarios. We include our ScotNS production forecast for reference. Three of our scenarios imply production pathways with more rapid declines than our ScotNS forecast. These are the ones based on historical emissions and comparative affordability. While these are consistent with faster emissions reductions, they also highlight the trade-offs with wider economic and social factors. These are considered on the next page.

### Scotland's potential production pathways




*Source: EY analysis*

# Just Transition scenario impacts



## Factors to consider

The climate emergency requires significant action from government, private companies and consumers, but the full implications of any policy option need to be properly understood and assessed – doing so is critical to delivering a Just Transition.

Subsequent analysis on the full impacts of different production pathways will follow in future phases of work, but we have highlighted some of the key factors that will need to be considered to arrive at a balanced and just policy position.

### Economic impact

**O&G continues to make a significant contribution to the Scottish economy. A Just Transition must consider the full implications of a decline in O&G production on the Scottish economy and minimise the negative impacts**

The industry is responsible for a total GVA of £18.0bn, equivalent to 10% of total Scottish GDP. Even with a reduced output compared to the peak in 1999, it still represents a significant contribution to the economy of Scotland and in particular that of the North East. Scotland is well placed to attract investment in green technologies and sectors, but transitioning takes both time and investment. Accelerating the decline of an industry may risk materially impacting economic output, although continuing to supporting investment in a sector that is declining may draw capital and skills away from more sustainable sectors. A Just Transition will need to deliver on this delicate balance.

### Jobs and skills

**O&G is a significant employer in Scotland, particularly in the North East. A Just Transition should consider potential impacts on people's livelihoods and enable the workforce to transition to more sustainable sectors**

Our analysis indicates that the O&G sector provides 79,000 jobs with 98% of the direct O&G jobs located within the North East. The impacts of the energy transition are already being seen across the workforce, increasingly skills from the O&G sector are being sought in offshore wind or emerging sectors such as hydrogen and CCUS. There is some overlap in the skillsets for O&G and for renewable technologies, particularly those that involve offshore operations. The NSTD included a set of actions on training and mapping skillsets to help workers transition, but there will be dislocation for workers and differences between the nature of jobs in oil services and jobs in installation & O&M for offshore renewables. An accelerated decline in the O&G sector may pose a risk to jobs with the impact felt disproportionately in the North East as it is more difficult to predict where new jobs will arise given the more distributed nature of renewables.

### Energy costs

**Increased reliance on imported O&G for consumption may leave Scotland more susceptible to O&G price spikes. A Just Transition should consider future demand for O&G and ways of protecting consumers from price effects**

The SG has ambitious targets to transition from fossil fuels to low carbon alternatives, but at present there continues to be a heavy reliance on fossil fuels. Certain sectors such as transport and heat have been particularly hard to decarbonise, with the SG estimating that 81% of households rely on mains gas for heating in 2019. Recent spikes in gas prices, which have been exacerbated by the UK's reliance on gas imports, have also demonstrated Scotland's susceptibility to gas prices for both electricity generation and heat.

Reducing Scotland's reliance on fossil fuels will assist with this problem, but any production pathway needs to consider the implications for O&G prices and the potential impact on Scottish people.

### Energy security

**A Just Transition must consider how best to secure resilient and flexible supplies of O&G to support ongoing domestic demand**

The UKCS has maintained the country's energy security since production started in the 1960s. Although Scotland's energy landscape is changing and there is a continued trend to reduce domestic O&G demand, ensuring a secure, resilient and flexible energy system is an important consideration as Scotland develops its Just Transition energy strategy. In the short term, reduced gas production means greater reliance on the import of gas in a macroeconomic situation where supplies are under pressure and prices are consequently very high.

# Just Transition scenario impacts (cont'd)



### Carbon emissions associated with production and transportation

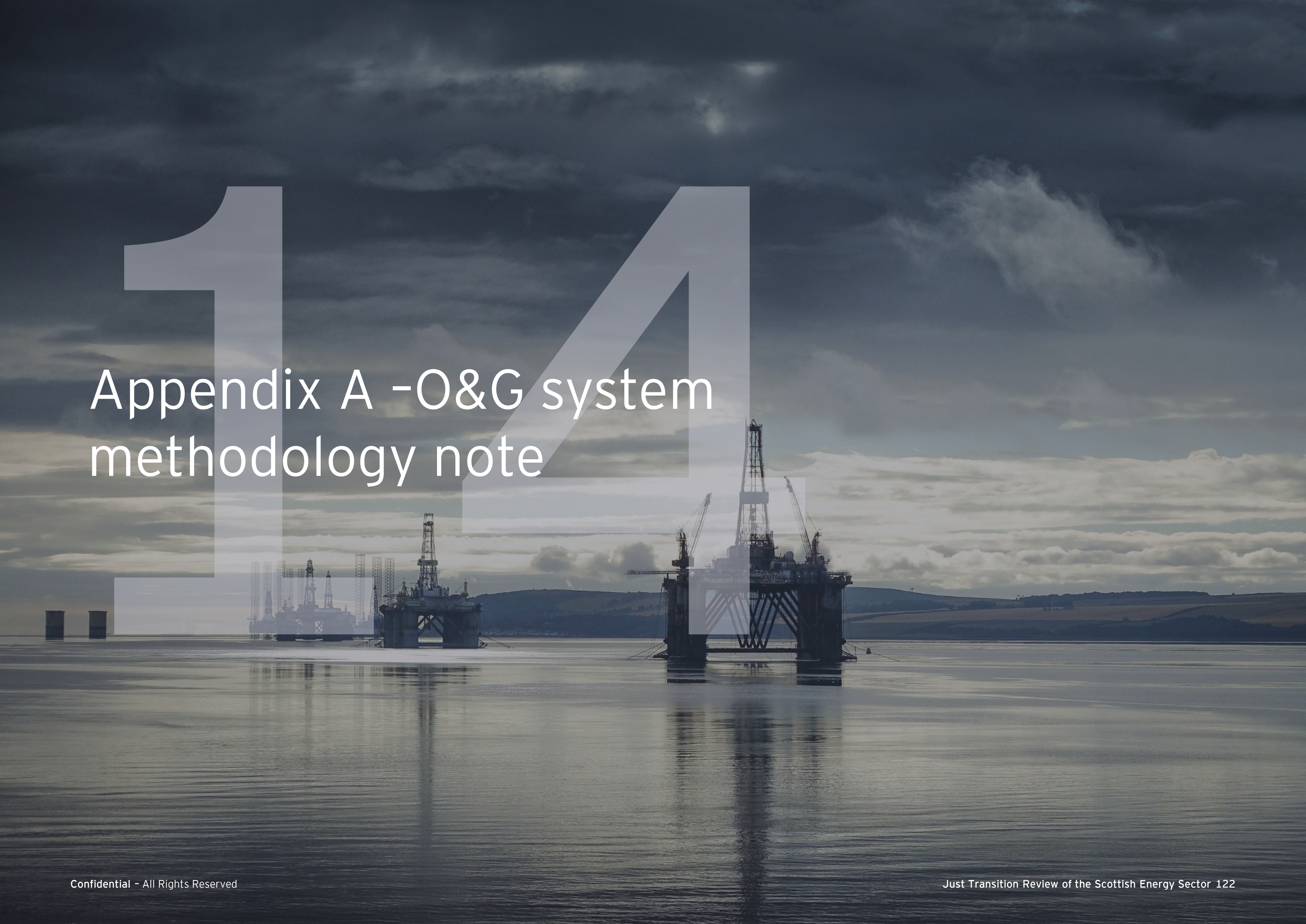
**A Just Transition should aim to minimise the environmental impact of O&G that is needed for domestic consumption by considering the carbon intensity of ScotNS compared to imported products**

North Sea O&G production is highly regulated and, with the introduction of the NSTD, emissions from the UKCS are forecast to continue to fall. Furthermore, local production of O&G will incur less transportation emissions compared to imports from overseas basins. Carbon emissions from imported O&G, particularly liquefied natural gas, may exceed emissions from decarbonised North Sea production. As a result, maintaining domestic O&G production can lead to lower net emissions and still contribute to Scotland's Just Transition.

### Supply Chain

**The O&G sector supports a significant supply chain in Scotland. A Just Transition plan must consider the full effects on the domestic supply chain and how best to capture supply chain opportunities in low carbon sectors**

The Scottish O&G sector has developed a significant supply chain across the UK. Whilst the renewables sector has grown over the last decade, it has so far not captured supply chain benefits in the same way. Further analysis is required to understand how a transition away from O&G will impact this supply chain and how it can pivot to support Scotland's new low carbon landscape.



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# Appendix A –O&G system methodology note

# Appendix A
# The O&G System – Methodology note


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### Methodology note for Sections 7-11

The figures in this section are based on the following statistical sources:

- Scottish Government - Commodity Balances, Exports and Imports of Oil, Gas and Petroleum 2019 (Experimental statistics based on published BEIS UK data)
- BEIS Digest of UK Energy Statistics (DUKES) – 3.1 Primary oil: commodity balances, 3.2 Petroleum products: commodity balances and 4.2 Natural gas: commodity balances
- BEIS Energy Trends: Table 4.4 Supplementary information on the origin of UK gas imports
- Department for Transport – Port freight annual statistics 2019
- WoodMac Refinery Evaluation Model – Grangemouth

2019 data has been used as this was the last year where a full picture was available for Scottish commodity balances. 2019 also depicts a more accurate reflection of trends over time, as abnormal events such as COVID-19 affected global demand in 2020 and 2021.

The following general methodological approach was taken:

- Scottish figures are estimated using relevant indicators in order to derive a top-down apportionment of UK data. Where possible these have been corroborated with aggregated actual regional data.
- For example, according to the Scottish Natural Capital Accounts (2021), Scotland produced 95% of the UK's crude oil and NGL. As such, the Scottish share of all upstream primary oil products is assumed to be 95% of the BEIS DUKES Commodity Balance.
- Scotland's only refinery, Grangemouth, is one of six major refineries in the UK and accounts for c.14% of total UK refining capacity. As such, figures relating to the downstream process (such as feedstocks or production of petroleum products) have been calculated as a 14% share of the BEIS DUKES Commodity Balance.
- UK Port Freight Statistics have been used to corroborate the imports and exports of primary oil products and downstream O&G products.
- Natural gas production has been built up aggregately from ScotNS field level data, with imports and exports taken from BEIS Energy Trends.
- Natural gas figures are reported by BEIS in GWh. To allow the data to be compared and aggregated, this has been converted to ktoe using the International Energy Agency (IEA) rate of 1GWh:0.085985ktoe.
- Upstream Primary oil products and Downstream Oil & Oil products are reported by BEIS in metric tonnes. It has been assumed that 1,000 metric tonnes equates to 1ktoe of energy expended.

We note that import and export data is also available from the HMRC Regional Trade in Goods Statistics. We have not used the HMRC trade data in the writing of this report for a number of reasons – primarily because it reports on the value of imports and exports in GBP rather than volumes. The HMRC data also does not clearly split out energy products into primary oil products, refined oil & oil products and natural gas, and its apportionment methodology is employment based rather than using relevant bases such as refinery capacity or the split of ScotNS fields vs. wider UKCS.

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# Appendix B - Scotland in a global context

# Appendix B
# Scotland in a global context



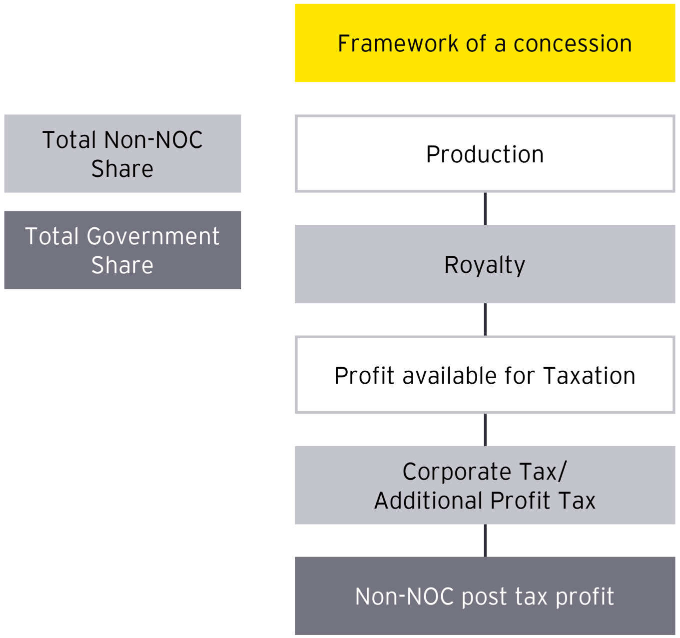
## Fiscal Contracts

Below is a pictorial presentation of cash flows which a contractor can be expected to gain under different contract types.

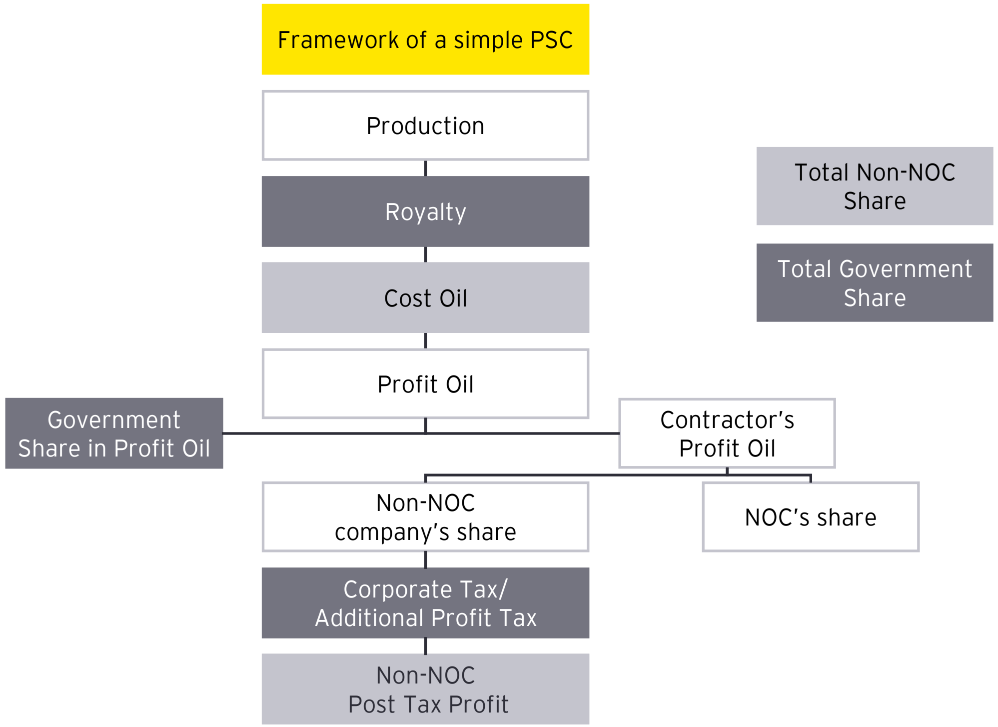
As mentioned in Section 12, fiscal structure is a combined system of tax and non-tax instruments. Unlike a conventional manufacturing business wherein profits are a function of revenue and sales, fiscal structures include not only standard instruments such as royalty, production/signature bonuses and corporate income tax, but also contractual schemes such as production-sharing and other relevant mechanism (sharing of production/profit, right of back-in into the field/block), which makes the evaluation complex.

These terms play an integral role in companies' evaluation of opportunities to determine overall cash flows, return (IRR), Net Present Value (NPV) for investment decision making.

### Examples of fiscal contracts and their characteristics




- Cost Oil: there is no recovery of cost; cost is born by contractor
- Profit Oil: Other than corporate tax, there is no additional burden on contractor which needs to be shared
- NOC: National Oil Company typically does not have a back-in right




- Cost Oil: share of total production, which can be retained by the contractor to recover costs incurred, normally subject to maximum cost (cost oil limit)
- Profit Oil: share of remaining oil after cost recovery. Profit oil is split between government and contractor to a formula set out in PSC
- NOC: National Oil Company typically has a back-in right once the project is de-risked

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# Appendix C – Global comparison analysis

# Appendix C
# Global comparison



This sub-section compares the UK with other prominent O&G countries. The comparator countries were selected as they have significant levels or high production potential and offer varied field types. Additionally, these countries compete with the UK in attracting investment, owing to resource potential, ease of doing business and fiscal attractiveness. We have summarised these countries below, providing an overview of the resource and prospectivity, type of fields and key fiscal terms.

| | Particulars | UK | Norway | US | Canada | Saudi Arabia |
|---|---|---|---|---|---|---|
| Prospectivity and landscape | Oil Reserves (billion bbls) | 2.5 | 7.9 | 68.8 | 168.1 | 297.5 |
| | Crude and NGL Production (2020, oil Mmbbls/d) | 1.0 | 2.0 | 16.5 | 4.1 | 11.0 |
| | Gas Reserves (tcm) | 0.2 | 1.4 | 12.6 | 2.4 | 6.0 |
| | Gas (2020, bcm) | 39.5 | 111.5 | 914.6 | 165.2 | 112.1 |
| | National Oil Company (NOC) | N/A | Equinor | N/A | N/A | Saudi Aramco |
| | Self Sufficiency | Importer | Exporter | Exporter | Exporter | Exporter |

| | Major type of fields | Offshore | Offshore | Unconventional (onshore), shallow offshore | Onshore, Oil Sands | Onshore Conventional |
|---|---|---|---|---|---|---|
| Key fiscal terms | Contract Type | Concession | Concession | Concession | Concession | PSC |
| | Royalty | N/A | N/A | 12% - 30% | Upto 45% | |
| | Cost Recovery | N/A | N/A | N/A | N/A | N/A |
| | Profit Sharing | N/A | N/A | N/A | N/A | N/A |
| | Corporation Tax/ Additional Petroleum Tax | 30%<br>10% (Supplementary charge) | 22%<br>56% (Special petroleum tax) | 21%-29% | 25% -31% | 50%-85% |
| | State Participation/ Carried interest | × | × | × | × | ✓ |
| | Bonuses | × | × | Negotiated with mineral owner | × | ✓ |

# Appendix C
# Global comparison (cont'd)



This sub-section compares the UK with other prominent O&G countries. The comparator countries were selected as they have significant levels or high production potential and offer varied field types. Additionally, these countries compete with the UK in attracting investment, owing to resource potential, ease of doing business and fiscal attractiveness. We have summarised these countries below, providing an overview of the resource and prospectivity, type of fields and key fiscal terms.

| | Particulars | UK | Brazil | Russia | Qatar |
|---|---|---|---|---|---|
| Prospectivity and landscape | Oil Reserves (billion bbls) | 2.5 | 11.9 | 107.8 | 25.2 |
| | Crude and NGL Production (2020, oil Mmbbls/d) | 1.0 | 3.0 | 10.7 | 1.8 |
| | Gas Reserves (tcm) | 0.2 | 0.3 | 37.4 | 24.7 |
| | Gas (2020, bcm) | 39.5 | 23.9 | 638.5 | 171.3 |
| | National Oil Company (NOC) | N/A | Petrobras | Gazprom, Rosfnet | Qatar Energy, Qatar Gas |
| | Self Sufficiency | Importer | Exporter | Exporter | Exporter |

| | Major type of fields | Offshore | Offshore (Pre-salt) | Offshore (Gas) | Offshore (LNG) |
|---|---|---|---|---|---|
| Key fiscal terms | Contract Type | Concession | PSC | Concession | PSC |
| | Royalty | N/A | 15-20% | ✓<br>Mineral Extraction Tax (MET)<br>Export Duty | ✓ |
| | Cost Recovery | N/A | ✓ | N/A | ✓ |
| | Profit Sharing | N/A | On a sliding scale 40-90% based on R-factor | N/A | ✓ |
| | Corporation Tax/ Additional Petroleum Tax | 30%<br>10% (Supplementary charge) | 34% | 20%<br>(Tax on additional income for specified projects - 50%) | 35% |
| | State Participation/ Carried interest | × | × | ✓ | ✓ |
| | Bonuses | × | ✓ | ✓ | ✓<br>(Additional production bonus) |

# Appendix C
# Global comparison (cont'd)



The table below provides an overview of the O&G opportunities and strengths they offer to the operator to efficiently continue operations and production.

| Opportunities and strengths | | | | |
|---|---|---|---|---|
| **The UK** | **Norway** | **US** | **Canada** | **Saudi Arabia** |
| ▶ Established basin with large resource base<br>▶ Hub for global O&G expertise<br>▶ Continued high interest in potential licensing round<br>▶ World class supply chain acts as a key strength<br>▶ Opportunity to unlock potential from mature fields through collaboration with supply chain partners (EOR/IOR) | ▶ Attracted investments owing to abundance of resources and higher probability of exploration success<br>▶ Despite peaking in early 2000's, several notable discoveries have reinforced this positioning<br>▶ Presence of local and international suppliers and service companies across the entire value chain supported growth of the industry<br>▶ Some of the areas are yet unexplored, like Barents Sea, providing new opportunity<br>▶ Country pioneered several innovations in the past like floating production platforms (1992), 4D seismic (1999) and subsea processing (2007), etc. | ▶ Second largest producer and consumer of hydrocarbon in the world<br>▶ Shale/unconventional growth supported the US achieving self sufficiency in both oil and natural gas<br>▶ Extremely strong infrastructure (pipeline, LNG, refiners) to enable easy consumption and transportation access for the final product | ▶ Fifth largest hydrocarbon producer; generally perceived as attractive country owing to resource abundance and stable policies<br>▶ Third largest country in terms of proven oil reserves<br>▶ Large opportunity for shale which are largely unexplored<br>▶ Opportunity to transport crude by sea to large vector markets like China, India whilst maintaining cost competitiveness specially in LNG/Gas segment | ▶ Holder of one of the largest and yet unexplored reserves in the region<br>▶ Oil dominated, lowest quartile cost of production<br>▶ Unexplored reserves with periodic large discoveries; shale /unconventional potential untested<br>▶ Potential to invest through public partnership model<br>▶ Opportunities in related O&G sector like downstream, petrochemicals |

# Appendix C
# Global comparison (cont'd)

The table below provides an overview of the O&G opportunities and strengths they offer to the operator to efficiently continue operations and production.

**Opportunities and strengths**

| The UK | Brazil | Russia | Qatar |
|---|---|---|---|
| ▶ Established basin with large resource base<br>▶ Hub for global O&G expertise<br>▶ Continued high interest in potential licensing round<br>▶ World class supply chain acts as a key strength<br>▶ Opportunity to unlock potential from mature fields through collaboration with supply chain partners (EOR/IOR) | ▶ World class pre-salt discoveries in last decade - high success exploration in the Campos and Santos basin, large scale discoveries, high commercial value light oil<br>▶ New discoveries complimented by production from mature basin<br>▶ Favourable fiscal terms with successful multiple bid rounds in past across a number of basins<br>▶ Changes in regulation ranging from relaxing local content rules to ending Petrobras's monopoly in pre-salt operatorship<br>▶ International investment to drive expansion in pre- and post-salt exploration and production | ▶ A leading and important supplier of gas to European market<br>▶ Natural gas reserves are not limiting factor with dominant position of Gazprom (publicly owned entity)<br>▶ Huge unconventional potential untapped | ▶ Key player globally in the LNG export industry<br>▶ Continuous expansion in LNG to become world biggest producer of LNG |

# Appendix C
# Global comparison (cont'd)



The below table provides an overview of the challenges and barriers which operators might face when considering investment in these individual countries.

| Key barriers and challenges | | | | |
|---|---|---|---|---|
| **The UK** | **Norway** | **US** | **Canada** | **Saudi Arabia** |
| ▶ Relatively high cost base<br>▶ Limited recent exploration success has led to lower investment and interest in the sector<br>▶ Offshore production results in a higher cost of extraction compared to oil produced in onshore terrains especially in the Middle East | ▶ Though there are abundant resources, some of the areas have more challenging reservoirs as most of the easy barrels have been produced<br>▶ Smaller new discoveries depend on cost effective solutions, standalone development might be challenging<br>▶ Offshore production results in a higher cost of extraction compared to oil produced in onshore terrains especially in the Middle East<br>▶ Further, higher labour costs in comparison to other countries, put increased pressure on higher productivity | ▶ Although the pipeline infrastructure is strong, further proposals to expand network have faced challenges and yet to be approved<br>▶ O&G sector is extremely competitive with new opportunities requiring significant initial cash outlay/premium | ▶ Production is primarily from oil sands which have higher cost and are relatively inflexible<br>▶ Bitumen rich production which is priced at steep discount and difficult to transport<br>▶ Net exporter, exposing operators to geopolitical and trade risk<br>▶ Mounting challenges due to environmental issues could lead to potential new developments in other non-O&G areas | ▶ Regional (fiscal deficit) as well as export dependency on oil<br>▶ Fiscal terms are generally onerous for operators<br>▶ Corporate governance and transparency is an issue in the region with limited disclosures<br>▶ Risk of supply disruption owing to geopolitical unrest may hamper supply reliability<br>▶ Investment barriers such as concerns about human rights record<br>▶ Low energy efficiency and large energy wastes hamper long-term energy balance<br>▶ Continuous focus globally on renewables/hydrogen/EV puts oil dependent region at significant risk |

# Appendix C
# Global comparison (cont'd)



The below table provides an overview of the challenges and barriers which operators might face when considering investment in these individual countries.

| Key barriers and challenges | | | |
|---|---|---|---|
| **The UK** | **Brazil** | **Russia** | **Qatar** |
| ► Relatively high cost base<br>► Limited exploration success has led to fewer investment and interest in the sector<br>► Offshore production results in a higher cost of extraction compared to oil produced in onshore terrains especially in the Middle East | ► Limited history for development of pre-salt discoveries<br>► Lack of infrastructure may lead to over reliance on FPSOs, limited gas monetisation option<br>► Despite pre-salt well productivity, the activity is technically challenging, with delays, cost overruns, and under performance<br>► If the productivity of future development wells falls short of expectations, projected economics may become marginal due to high upfront costs | ► Strong dominance of state owned companies (Rosneft, Gazprom, Lukoil) limits opportunities for smaller/ independent players<br>► Sanctions imposed by the US and EU coupled with political unrest impacts import and deployment of critical technologies and capital<br>► Ageing infrastructure (refinery, pipelines) coupled with over-utilisation creates logistics hurdles<br>► Majority of the untapped identified potential in tight oil and bitumen resources leading to higher cost of production<br>► Increasing competition in the LNG market from Qatar and Australia<br>► Recent changes in hydrocarbon tax pose a challenge and may lead to oil sands production uneconomical | ► Fiscal dependence is still high on hydrocarbon revenue<br>► Limited opportunities for participation in the industry with domestic NOC playing a key integral role<br>► Growing competition from Australia and Russia in LNG market affects Qatar's position |

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# Global comparison (cont'd)

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Every major country has committed to Net Zero transition and the table below summarises their targets and steps undertaken.

**Net Zero target and steps undertaken**

| The UK | Norway | US | Canada | Saudi Arabia |
|---|---|---|---|---|
| ▸ Target of Net Zero by 2050 for the rUK and 2045 for Scotland<br>▸ NSTD agreed with industry and government in Mar 2021<br>  ▸ Supply decarbonisation and reduction from offshore production by 50% in 2030<br>  ▸ Investment of £14-16bn in new energy technologies (CCUS/Hydrogen) by 2030<br>▸ However, exploration activities and future new licences are currently a source of political scrutiny<br>▸ In case of Scotland, in 2018 the government established Just Transition Commission (JTC) to advise on transitioning all sectors of the Scottish economy to become net-zero emissions | ▸ Net Zero target by 2030 revised from its earlier target of 2050<br>▸ Carbon tax and Greenhouse Gas Emission Trading Act from 2007, tax on NOx as tools for cost effective cut in greenhouse gases<br>▸ Decarbonisation of petroleum activities - invested in electrification of platforms, power from offshore wind farms, carbon capture and storage systems (CCUS) and Government, key O&G players have taken various initiatives/ entered into partnership around hydrogen, offshore wind<br>▸ However, the government continues to expand O&G industry by award of new licences and will pursue its exploration policy with regular concession rounds | ▸ Target to Net Zero by 2035<br>▸ Biden government has:<br>  ▸ Suspended oil and natural gas drilling leases in the Arctic National Wildlife Refuge<br>  ▸ Revoked permits for the Keystone XL pipeline<br>  ▸ Put stringent procedures in place to identify fossil fuel subsidies and take steps to stop them<br>  ▸ Also, USD 1tn Infrastructure Investment and Jobs Act includes a USD 21bn investment to plug and clean up abandoned coal mines and O&G wells which continue to emit significant amounts of methane and other pollutants | ▸ Target to Net Zero by Rosneft 2050<br>▸ Targets from methane emission reduction by 40-45% in 2025 from 2012 levels<br>▸ Mandatory carbon pricing in effect since 2019<br>▸ Setup a \$750m Emissions Reduction Fund (ERF) to invest in green solutions for O&G sector<br>▸ Also, country has setup a \$8bn Net-Zero Accelerator Fund to help large emitters reduce their emissions | ▸ Target to Net Zero by 2060<br>▸ Reduction of oil use for electricity generation and increasing renewable in electricity generation mix to 50%<br>▸ Aim to utilize Gas for blue hydrogen and become top hydrogen supplier in the world<br>▸ Saudi Aramco, state NOC, has Net Zero target of 2050 |

# Appendix C
# Global comparison (cont'd)

Home | 1 Executive Summary | 2 Introduction and background | 3 Scottish O&G production forecast | 4 Scottish O&G economic footprint | 5 Greenhouse Gas Emissions ... | 6 Infrastructure Summary | 7 The O&G Energy System | 8 Upstream Primary Oil Product... | 9 Upstream Primary Oil Product... | 10 Natural gas | 11 Downstream The Refining ... | 12 Global Context | 13 Scottish Production pathways | 14 Appendix

Every major country has committed to Net Zero transition and the table below summarises their targets and steps undertaken.

## Net Zero target and steps undertaken

| The UK | Brazil | Russia | Qatar |
|---|---|---|---|
| ▸ Target to Net Zero by 2050 for the rUK and 2045 for Scotland<br>▸ NSTD agreed with industry and government in Mar 2021<br>  ▸ Supply decarbonisation and reduction from offshore production by 50% in 2030<br>  ▸ Investment of £14-16bn by 2030 in new energy technologies (CCUS/Hydrogen)<br>▸ However, exploration activities and future new licence are currently a source of political scrutiny<br>▸ In case of Scotland, in 2018 the government established Just Transition Commission (JTC) to advise on transitioning all sectors of the Scottish economy to become net-zero emissions | ▸ Target to Net Zero by 2050<br>▸ No specific policy for O&G sector though Petrobras (NOC) committed to Net Zero and reduction by 25% by 2030<br>▸ The country, however, is expected to invest 77% in energy infrastructure going to O&G with fossil fuel share in electricity mix increasing from 14% to 18% in 2029<br>  ▸ As per plan, O&G production to increase from 3.2mmbbls/d and 130mmscf/d in 2020 to 5.5mmbbls/d to 253mmscf/d in 2029 | ▸ Target to Net Zero by 2060 (announced in Oct 2021, though not formally adopted)<br>▸ Country is fourth largest emitter of GHG in 2018<br>▸ Adopted Energy Strategy 2035 with intention to continuously support fossil fuel sectors<br>▸ Natural gas flaring has increased in last 3 years | ▸ Country has highest carbon per capita intensity<br>▸ Launched national climate change action plan with the aim of reducing greenhouse gas emissions by 25% by 2030 in Q4, 2021 including its carbon intensity from liquefied natural gas facilities by 25% by the same year |

# 17 Appendix D – transmittal letter

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## Just Transition Review of Scottish Energy Sector – Chapter 1

06 September 2022

Dear Sir/Madam

In accordance with our engagement letter dated 22 October 2021, we have prepared our report in relation to the Scottish Government's Just Transition review of the energy sector.

**Purpose of our report and restrictions on its use**

This report was prepared on your instructions solely for the purpose of the Scottish Government and should not be relied upon for any other purpose. Because others may seek to use it for different purposes, this report should not be quoted, referred to or shown to any other parties except as permitted under the Engagement Letter. Additionally, we have agreed that you may publish the whole of this report as a single document without amendment or redaction as a portable document format (pdf) file on the world wide web.

In carrying out our work and preparing our report, we have worked on the instructions of the Scottish Government. Our report may not have considered issues relevant to any third parties. Any use such third parties may choose to make of our report is entirely at their own risk and we shall have no responsibility whatsoever in relation to any such use.

At the time of writing this report O&G prices have been significantly impacted by war in Ukraine and the full economic consequences of this geopolitical risk cannot be fully predicted. Although we do not expect it to alter the underlying conclusions, any period of prolonged high prices will have an impact on future production forecasts. Historical geopolitical events have impacted oil prices but other factors, such as the response from other O&G producing nations will also need to be considered.

**Scope of our work**

Our work in connection with this assignment is of a different nature to that of an audit. Our report to you is based on inquiries of, and discussions with, Scottish Government. We have not sought to verify the accuracy of the data or the information and explanations provided by officials of the Scottish Government.

This report will provide a baseline review of the Oil & Gas sector in Scotland. It represents the first chapter in a multi-phase exercise which will support both policy development and the creation of a refreshed Scottish Energy Strategy and Just Transition Plan.

If you would like to clarify any aspect of this review or discuss other related matters then please do not hesitate to contact us.

Yours faithfully

Ernst and Young LLP

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