North Sea Transition Authority

Emissions Monitoring Report

2023

Contents

Executive summary

The North Sea Transition Deal (NSTD) was agreed by the UK government and the North Sea oil and gas industry in March 2021 to support the sector's transition to a low-carbon future. It set the industry a bold target of halving greenhouse gas (GHG) emissions from its production activities by 2030, against a 2018 baseline, on the path to net zero by 2050.

The North Sea Transition Authority (NSTA) is steadfastly holding industry to account on its emissions pledge, ensuring the UK has a secure supply of domestic oil and gas produced as cleanly as possible. Cutting emissions by 50% by 2030 is the absolute minimum the NSTA expects from industry, which must strive to meet and surpass the target.

Among other stewardship processes, the NSTA uses its annual Emissions Monitoring Reports to track industry's progress. First published in October 2021, these reports present a wide range of data on overall GHG emissions, methane emissions, performance benchmarking, and flaring and venting.

Key findings from the 2023 Emissions Monitoring Report include:

- In 2022, UK upstream GHG emissions fell by an estimated 3% year-on-year, contributing to a reduction of 23% between 2018 and 2022.
- Emissions reduced in 78% of offshore facilities between 2018 and 2022. 59% of the reductions were through active emission reduction measures with the rest via cessation of production.
- Combustion of hydrocarbons for offshore power generation offshore in 2022 made up 79% of emissions in 2022, followed

by flaring, 16%, venting, 4%, and other non-combustion processes, 2%.

- Total GHG emissions intensity decreased from 30.1 kgCO_2/boe in 2021 to 28.8 kgCO_2/boe in 2022. This metric includes GHG emissions from offshore facilities and onshore terminals.
- Flaring reduced by more than 10% last year, contributing to a reduction of nearly 50% between 2018 and 2022.
- Methane emissions are estimated to have fallen by more than 40% between 2018 and 2022 to fewer than one million tonnes of carbon dioxide equivalent – a record low.

The overall reduction in GHG emissions in 2022 is encouraging. The NSTA had anticipated that last year's small increase in UK North Sea oil and gas production would cause emissions to flatline or even temporarily rise. It also indicates industry is well on track to meet interim NSTD emission reduction targets of 10% by 2025 and 25% by 2027.

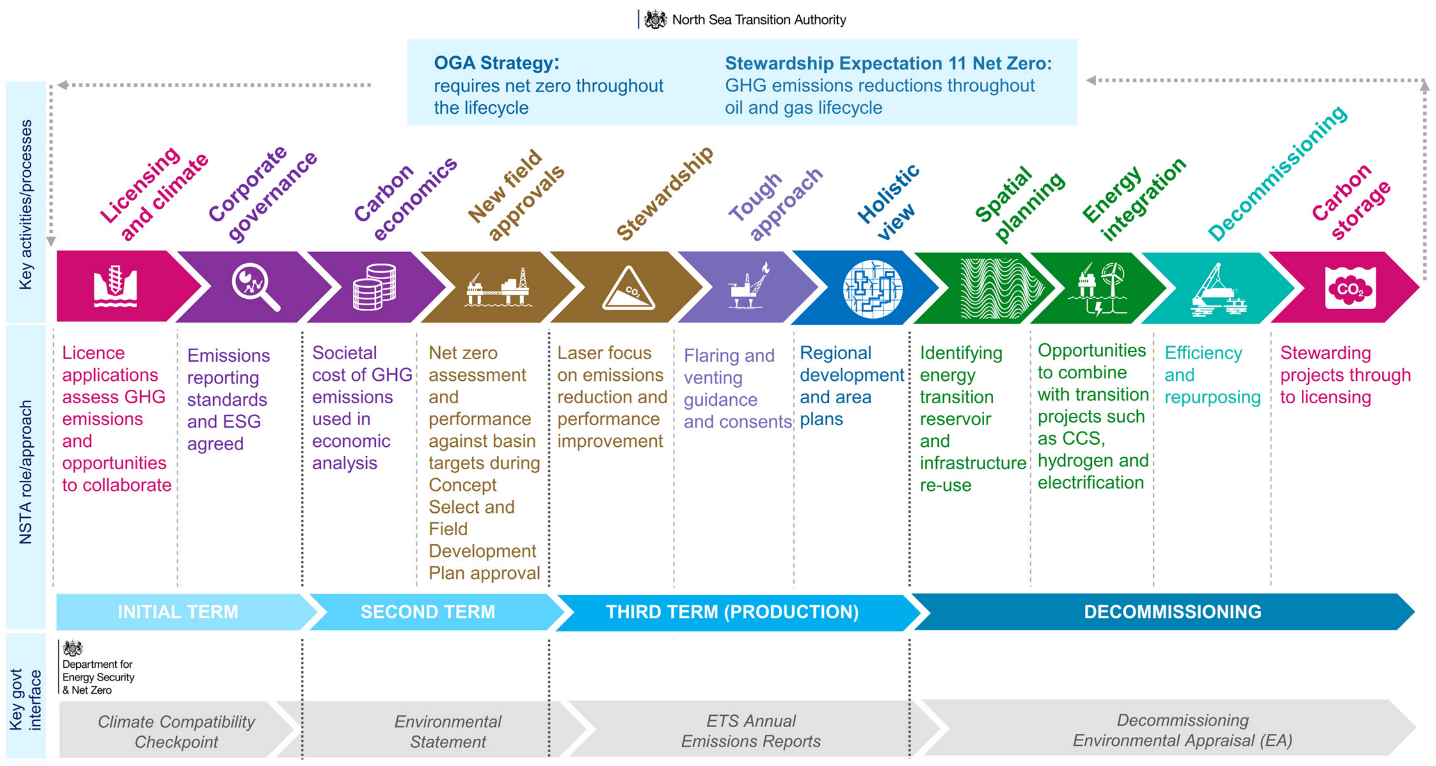
The NSTA is helping to deliver reductions by supporting and challenging industry. In line with its Strategy – revised in 2021 to oblige industry to support the UK's net zero ambition – the NSTA requires licensees to develop and implement Emissions Reduction Action Plans (ERAPs) for their operations. The NSTA also published tougher guidance stating all new developments should have no routine flaring and venting, with zero routine flaring across all North Sea facilities by 2030. Since then, NSTA interventions have contributed to preventing emissions of 3 million tonnes of lifetime CO_2 equivalent. This is the same as taking more than 1.5 million cars off the road for a year.

Examples of emissions reduction initiatives include a number of operators installing flare gas recovery systems, each estimated to save up to 22 tonnes of flared gas per day. Furthermore, an operator replaced components in a gas export compressor last year, lowering its fuel consumption by 18 tonnes per day and saving 20,000 tonnes of greenhouse gas emissions per annum. These investments not only support net zero – they also bolster the UK's energy security by saving gas that can be used to keep lights on, homes heated and businesses running.

Although industry is making strong progress, there is more work to do. The NSTA estimates that without the implementation of further emissions abatement initiatives, the sector will not meet the 2030 target. The NSTA will continue to press industry to live up to its commitments using its robust regulation and management, which includes the use of influence and Stewardship; monitoring, tracking and benchmarking; and setting out a Plan later in the year. The UK North Sea oil and gas industry can look to other similar basins for encouragement. While the carbon footprint of UK-produced gas is on average around a quarter of that of imported Liquefied Natural Gas (LNG), pipeline gas imported from Norway is cleaner, with less than half the production and transport-related carbon intensity of UK gas. The similarities between the UK and Norway offshore basins show there are considerable opportunities to make UK production even cleaner.

Operators must act on their ERAPs, 65 of which have been received and analysed by the NSTA, to date. The top three emissions reduction initiatives identified in ERAPs are the installation of flare gas recovery systems, lowering the fuel requirements of gas compressors, and projects to power platforms using clean electricity. Industry pledged to invest billions of pounds in platform electrification in the NSTD. Platform electrification remains essential to industry retaining its social licence to operate and in addition based on current projections, electrification projects could help the sector meet its emissions target.

Figure 1: NSTA lifecycle approach to net zero



About the data used in the report

The Department for Energy Security and Net Zero (DESNZ) publishes annual UK GHG figures for all sectors of the UK economy. GHG emissions from the UK upstream oil and gas industry can be extracted from this dataset using relevant Intergovernmental Panel on Climate Change (IPCC) categories (listed in Annex A):

Emissions under these IPCC categories cover the following activities:

- All fuel and non-fuel combustion emissions from offshore and onshore production facilities and onshore receiving terminals.
- Gas vented and unintentionally released to atmosphere (fugitives) from offshore and onshore production facilities and onshore receiving terminals.
- Gas flared from mobile drilling rigs during the drilling of exploration and appraisal wells.

Data are available on the following GHGs:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)

DESNZ data currently cover the period from 1990 to 2021. We expect information for 2022 to be published in early 2024.

1. Asset level GHG emissions are based on statistics from DESNZ **Environmental Emissions and Monitoring System (EEMS)**.
2. **UK Emissions Trading Scheme European Union Emissions Trading System (EU ETS) replaced participation in EU ETS in January 2021.**
   - Traded CO_2 emissions before 2021 are sourced from the EU ETS. Traded CO_2 emissions from 2021 onwards are sourced from the UK ETS.

About the data used in the report

3. **Numbers for previous years have been revised** in line with most recently published data sets. Therefore, variations in historic data compared with the past report are due to corrections or refinements of previously reported values.
4. **Non-carbon dioxide GHGs have been converted to carbon dioxide equivalent (CO_2e)** units using global warming potential (GWP) factors presented in the IPCC's Fifth Assessment Report (table 8.7, page 714). The GWP factors used are without inclusion of climate-carbon feedbacks and are over a 100-year timescale.
5. **Emissions Monitoring Report Dashboard and Annex.**

The report is accompanied by a dashboard that allows the user to conduct more detailed analysis of GHG emissions by UKCS region, year, type of oil and gas facility, and other relevant variables. The Annex presents additional details, defines the assumptions for the baseline projections, assumptions for the abatement scenarios, and lists relevant sources to the analysis of this report.

Greenhouse Gas	GWP100 (no cc fb)
Carbon dioxide (CO_2)	1
Methane (CH_4)	28
Nitrous oxide (N_2O)	265

1.1 Breakdown of industry GHG emissions

GHG emissions from upstream oil and gas activity accounted for 3% of net UK territorial GHG emissions in 2021 according to data from the National Atmospheric Emissions Inventory (NAEI).

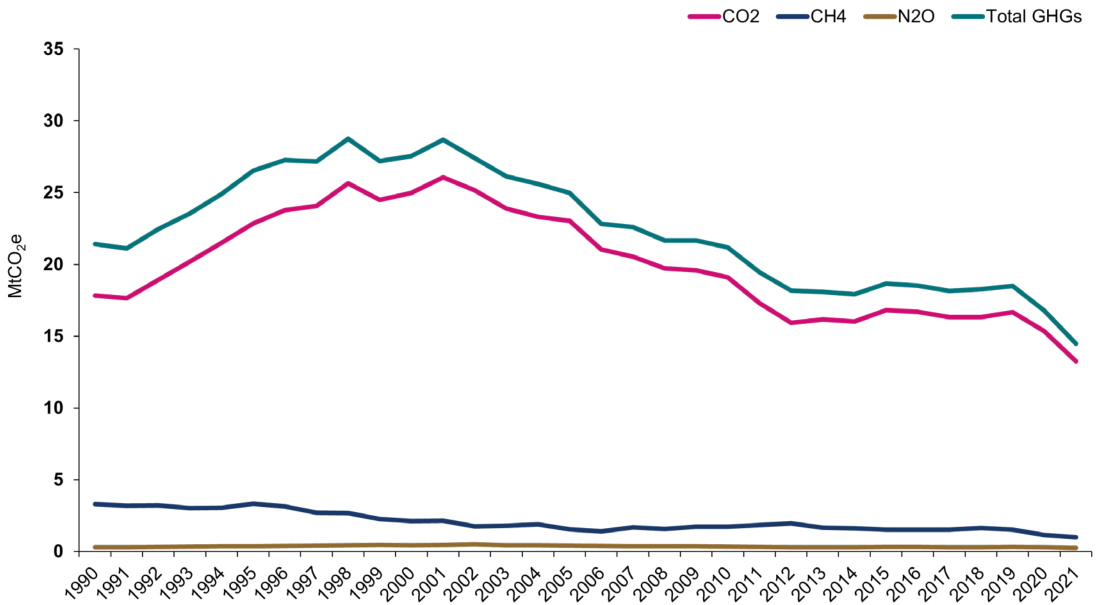
Carbon dioxide (CO_2) emissions drive the overall trend in GHG emissions from upstream oil and gas production in the UK. From 1990 to 2021, CO_2 accounted for 89% of total upstream emissions on average with methane (CH_4) and nitrous oxide (N_2O) comprising the remaining 9% and 2% respectively in carbon dioxide equivalent terms.

Emissions peaked in the early 2000s as new facilities were commissioned and brought online. When production fell and decommissioning of older installations began, emissions fell, albeit at a slower rate than production.

Total emissions remained relatively flat in the 2010s but from 2019 have been falling due to a combination of proactive industry efforts to decarbonise, disruption caused by the COVID-19 pandemic and the continued cessation of production of older fields as they reach the end of their production phase.

Figure 2 shows how UK upstream oil and gas industry CO_2 emissions have reduced by 49% since their 2001 peak to stand at 14.5 $MtCO_2$ in 2021. Methane emissions halved between 1990 and 2006 and then remained relatively flat until 2018. Since then, they have fallen by 40% to under 1 $MtCO_2e$ in 2021 – the lowest value recorded in the NAEI database. Nitrous oxide emissions rose to nearly 0.5 $MtCO_2e$ in 2002 but since then have fallen by 49% to 0.25 $MtCO_2e$ in 2021.

Figure 2: UK upstream oil and gas emissions by gas, 1990–2021 (source: NAEI)



Emissions of these three GHGs combined totalled 14.5 $MtCO_2e$ in 2021 from upstream oil and gas.

Significant reductions in CO_2, N_2O and CH_4 emissions have been achieved since 2018, as shown in Figure 3.

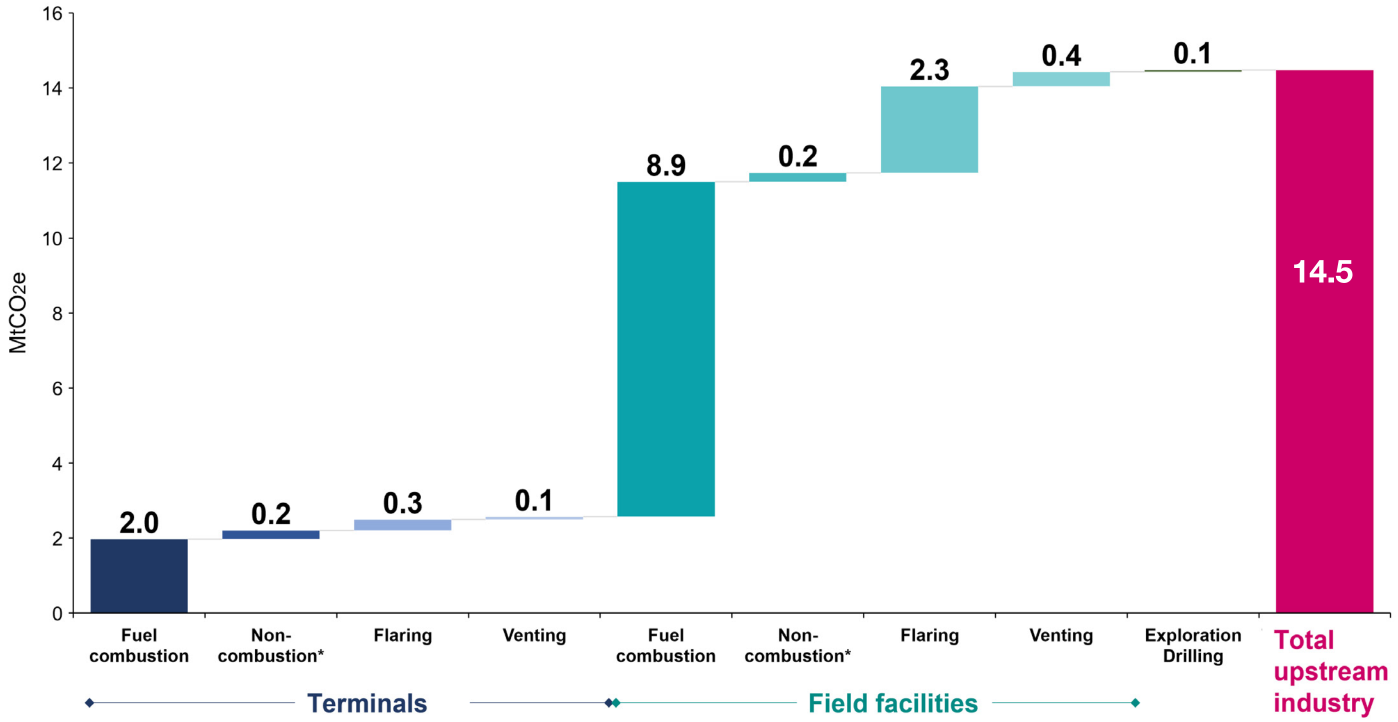
Figure 3: Table of UK upstream oil and gas GHG emissions reductions to 2021 (source: NAEI)

Greenhouse Gas	% Change from 1990 to 2021	% Change from 2018 to 2021	% Change from 2020 to 2021
N_2O	-18%	-16%	-15%
CH_4	-70%	-40%	-15%
CO_2	-26%	-19%	-14%
Total GHGs (CO_2e)	**-32%**	**-21%**	**-14%**

Of the 14.5 $MtCO_2e$ of GHGs emitted from the upstream oil and gas industry in 2021, 81.9% were from offshore facilities which extract and initially process oil and gas. These produced fluids are then generally* transported via pipelines to terminals which process them ready for market. Terminal emissions comprise 17.7% of the industry total. The remaining 0.4% of industry emission are associated with exploration drilling. Figure 4 gives a full breakdown of 2021 GHG emissions by source.

* Some field facilities process oil and gas to market specifications.

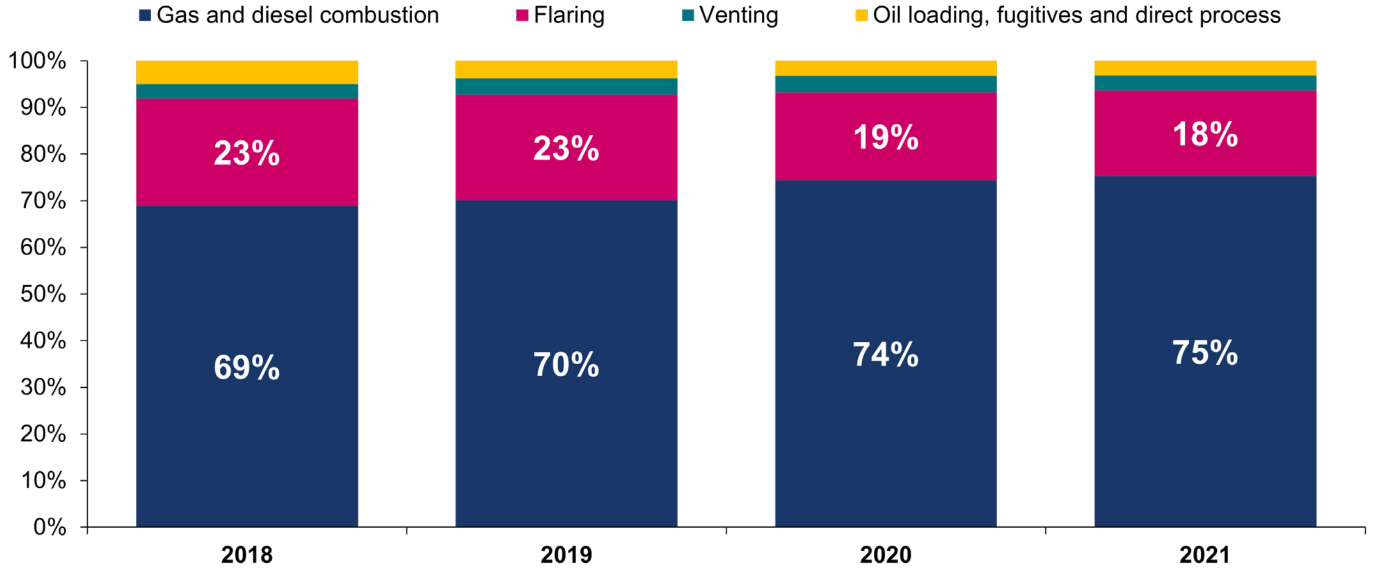
Figure 4: 2021 industry GHG emissions by source (source: NAEI)



*Process emissions, oil/ gas terminal storage, oil loading and fugitives

The combustion of hydrocarbon fuels for power generation or mechanical drive is the main source of emissions in both terminals and offshore facilities. The proportion of the total it comprises has grown from 69% in 2018 to 75% in 2021 as emissions from other sources – particularly flaring – have fallen at a greater rate. Flaring follows at 18% of total GHG emissions in 2021, down from 23% in 2018. Venting and other non-combustion processes have similar levels with 4% and 3% respectively. A summary of how the shares of these emissions have changed by source since 2018 is presented in Figure 5.

Figure 5: Industry GHG emissions per source: 2018–2021 (source: NAEI)



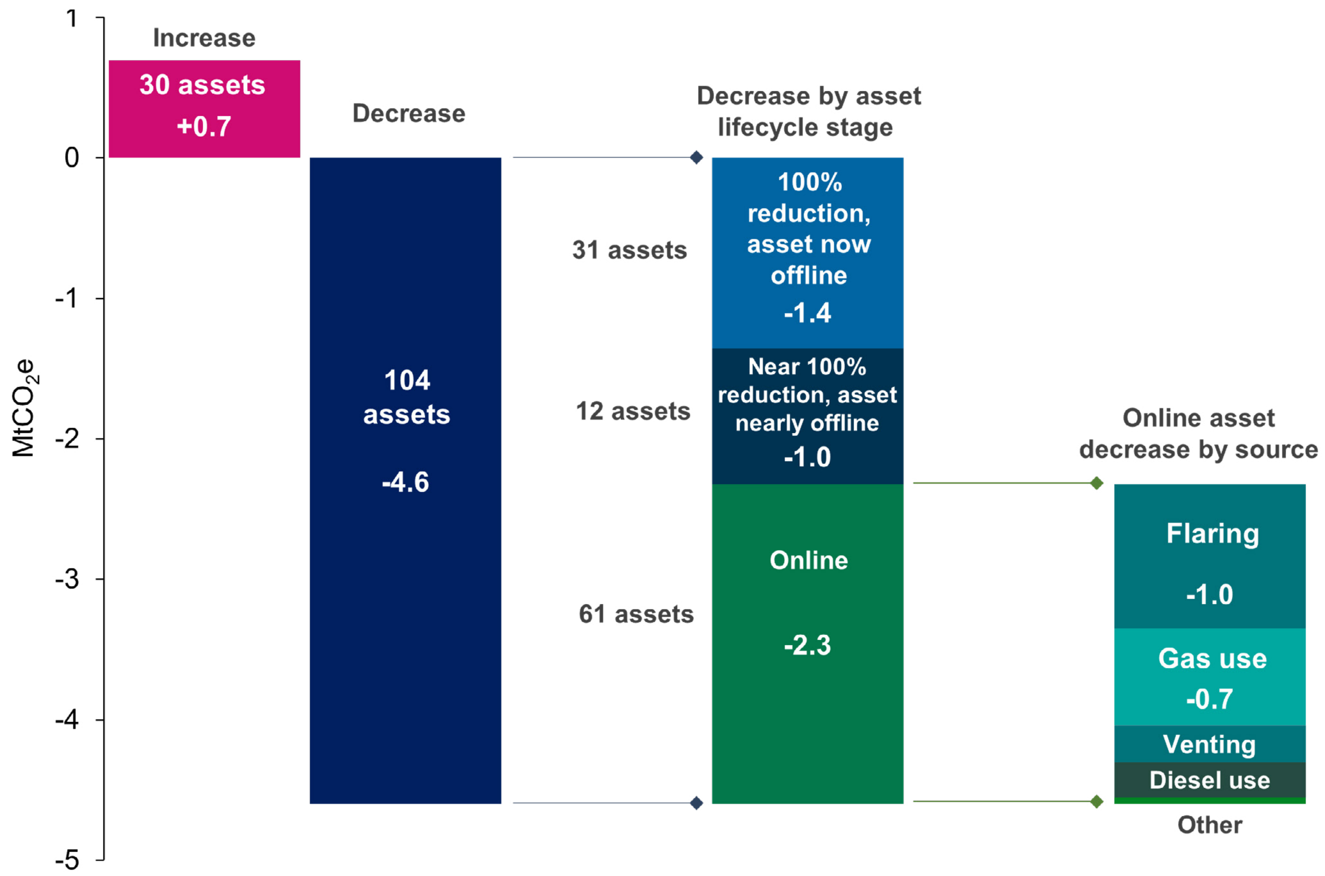
The Offshore Petroleum Regulator for Environment and Decommissioning's (OPRED's) Environmental and Emissions Monitoring System (EEMS) records a subset of total industry GHG emissions up to 2022. Using EEMS data, (which solely covers offshore assets and excludes onshore terminals and fields) shows that, despite falling by 0.2 $MtCO_2e$, emissions resulting from power generation (gas and diesel use) now comprise 79% of all GHG emissions offshore. This is due to a 19% fall in recorded flaring emissions which was key in driving a 5% reduction in overall offshore emissions from 11.2 $MtCO_2e$ to 10.6 $MtCO_2e$.

1.2 2018 to 2022 decarbonisation pathway

For offshore facilities, the latest EEMS data shows that between 2018 and 2022, GHG emissions decreased by 3.9 $MtCO_2e$ – a significant reduction of 27%. Figure 6 shows the drivers of this reduction.

From an inventory of 134 assets, 30 increased their emissions during this period, however most of which were bringing online new production. 104 assets decreased their emissions in this timeframe among which 43 installations reached the end of their operational life. The remaining 61 installations reduced their emissions while continuing to produce hydrocarbons. For these facilities, the primary driver was the curtailment of flaring activity and its associated emissions.

Figure 6: Breakdown of 2018–2022 offshore GHG emissions change (source: EEMS, NSTA)

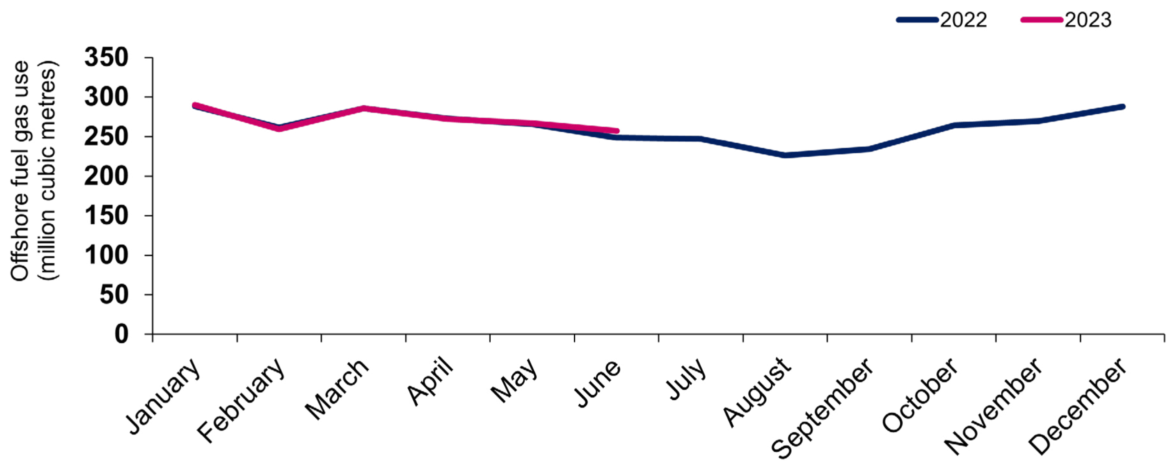


1.3 Year-to-date emissions in 2023

The use of produced gas for fuel by offshore facilities has a strong relationship with overall upstream emissions (see Annex C). Consequently, it is possible to monitor in-year emissions reduction progress using outturn data for gas utilisation in 2023 from the NSTA's Petroleum Production Reporting System (PPRS).

Following usual seasonal patterns, the first half of 2023 has seen near identical levels (0.5% higher) of fuel gas utilisation compared to 2022 suggesting that offshore emissions in 2023 will be at a similar level overall to 2022. This potentially indicates a slowing in the rate of emissions reductions across industry (see Figure 7).

Figure 7: Offshore fuel gas usage, January 2022 to June 2023 (source: PPRS)

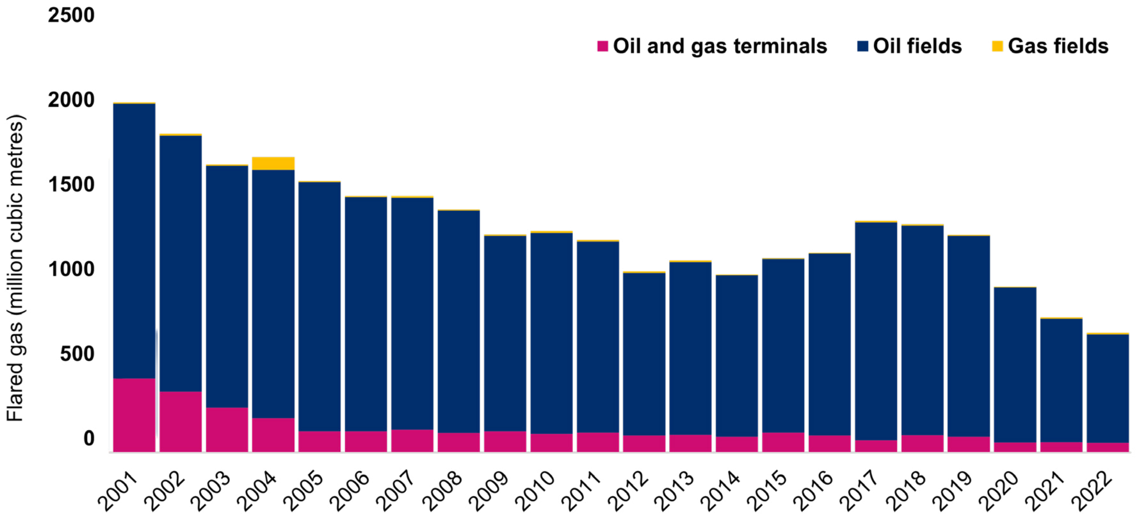


1.4 Flaring and venting activity

Total gas flared from the UK upstream oil and gas industry in 2022 was 708 million cubic metres (mcm) with 92% of the flaring coming from offshore facilities and 8% coming from terminals. This value is an 11% decrease from 2021 and a 48% reduction from 2018.

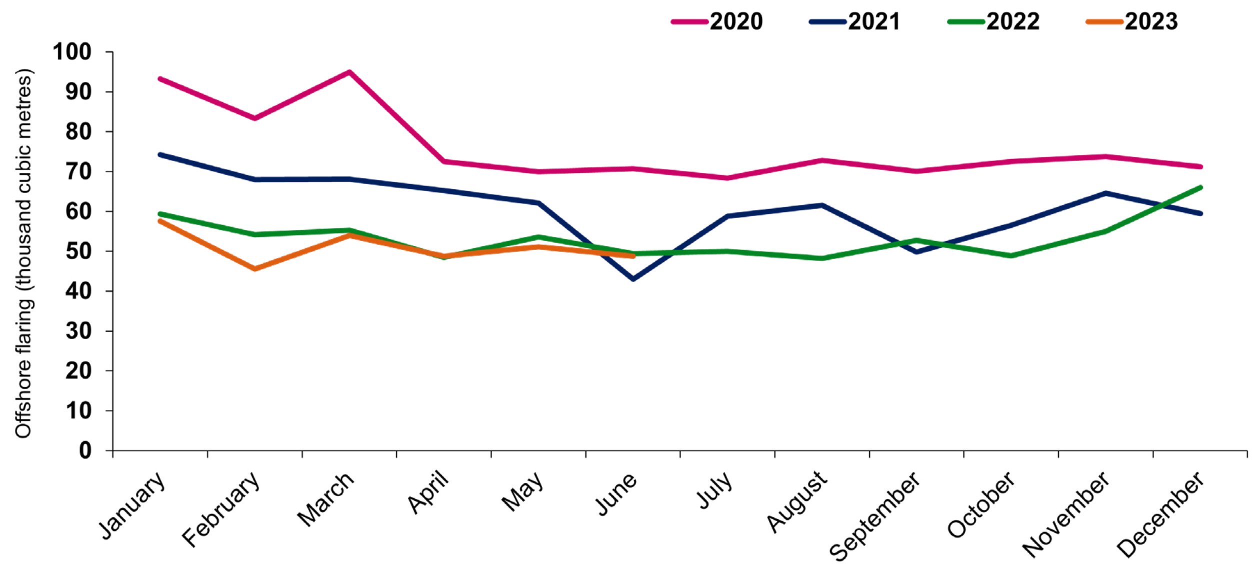
Figure 8 shows how total flaring levels fell steadily from the early 2000s to 2012, before rising again to 2019 in a period where oil and gas production saw a resurgence. Since 2019, significant reductions have been realised.

Figure 8: UK upstream oil and gas flaring, 2000–2022 (source: Digest of UK Energy Statistics E.1 (DESNZ)



Monthly data reported through PPRS shows a slight upwards flaring trend in Q4 2022 has been reversed in 2023. Gas flaring during the first half (H1) of 2023 has been slightly lower (by 3%) than the same period in 2022 while February 2023 saw the second lowest ever recorded month of flaring from fields. However, the magnitude of the reduction in H1 2023 is smaller than in recent years.

Figure 9: Monthly offshore flaring, January 2020 to June 2023 (source: NSTA)

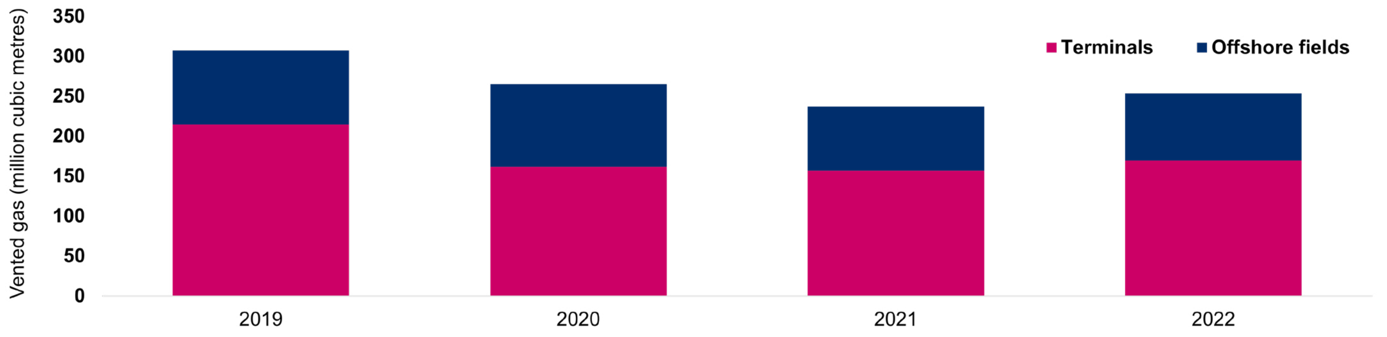


Following a two-year fall from 2019 to 2021, offshore venting rose by 5% in 2022 and by 7% overall (i.e. including terminals). This was predominantly due to levels recovering from the particularly low level experienced in 2021.

Figure 10 shows how the majority of gas vented from the industry is from onshore terminals, which is the opposite to flaring, where most activity occurs offshore. Venting figures are heavily influenced by a few key field and terminal sites where high levels of carbon dioxide are removed or 'scrubbed' from the natural gas stream and vented to the atmosphere. Variation of the venting levels from these select number of facilities can skew the annual change figures, which was the case for the slight increase in venting experienced in 2022. This explains how while methane emissions reduced in 2022, venting activity increased.

Latest figures show that 51% of offshore field venting and 49% of offshore field flaring is done so routinely. This highlights the significant challenge that the industry faces to eliminate routine flaring and venting by 2030 (see section 3.2).

Figure 10: Annual venting by facility type, 2019–2022 (source: Digest of UK Energy Statistics E.1 (DESNZ))



1.5 Methane emissions

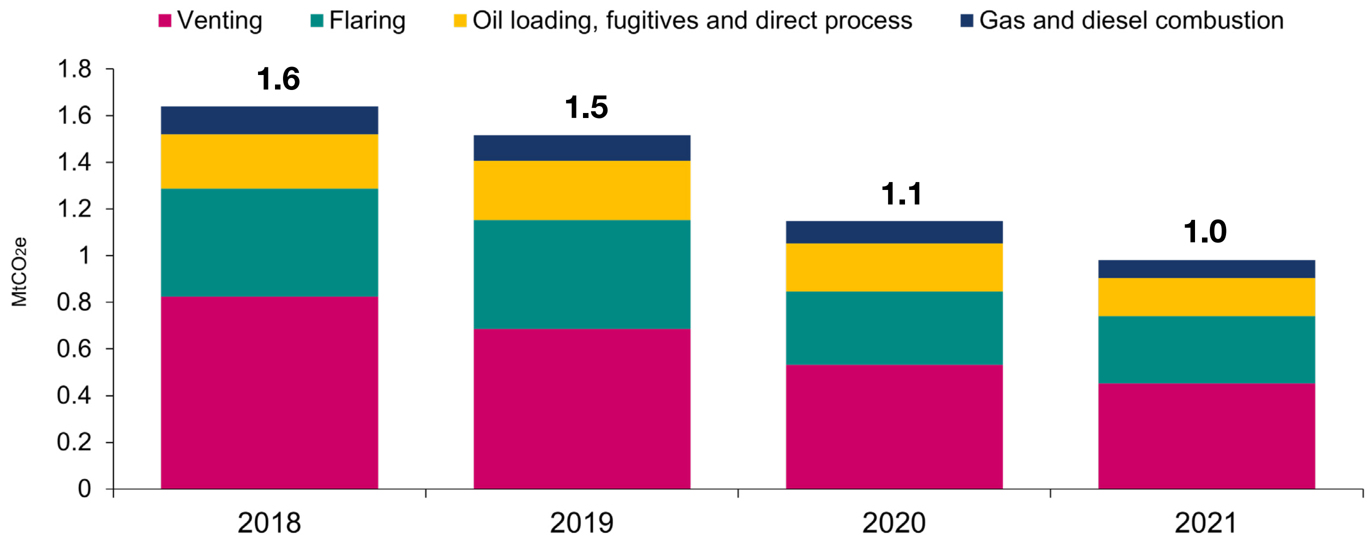
While the industry's GHG emissions footprint is mostly determined by CO_2 output, in 2021 methane represented 7% of upstream GHG emissions on a carbon dioxide equivalent basis. This proportion has been falling from a high of 11%, experienced in 2012. Total industry methane emissions data for 2022 are not yet available, however EEMS data shows that in 2022 methane comprised 6.1% of GHG emission for offshore facilities on a CO_2e basis, compared with 5.9% in 2021.

As previously stated, total UK upstream oil and gas industry methane emissions were 35 thousand tonnes or 0.98 $MtCO_2$e in 2021. This is the lowest annual methane emission value recorded from the oil and gas industry and represents a 40% reduction relative to 2018, as illustrated in Figure 11.

The decreasing trend in methane emissions is a result of various factors: a reduction in overall gas production levels, recent reductions due to shutdowns and maintenance activities, and proactive initiatives from industry to reduce flaring and venting such as increasing equipment efficiency and leakage detection systems. The updated NSTA flaring and venting guidance strengthens stewardship, performance monitoring and benchmarking.

Flaring and venting comprised a fifth of total GHG emissions in 2021 but were responsible for three-quarters of methane emissions in the same year.

Figure 11: Offshore methane emissions by source, 2018–2021 (source: NAEI)

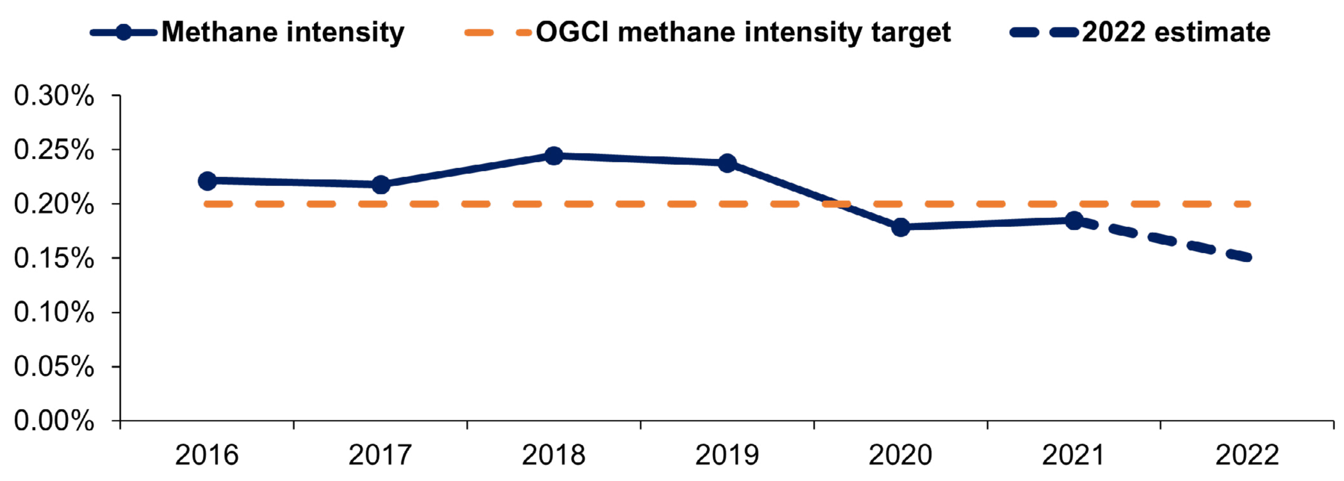


Between 2021 and 2022, EEMS data show that methane emissions are estimated to have very slightly decreased by around 1%. This flattening of methane emissions was a result of an increase in venting, but a larger decrease in flaring.

The United Kingdom is a participant in the Global Methane Pledge – a commitment to reduce methane emissions by least 30% from 2020 levels by 2030. The UK upstream oil and gas industry reduced its methane emissions by 15% between 2020 and 2021, with a further small decrease estimated in 2022. Despite this, there is still much work to be done to assist the wider economy in meeting this target.

Methane intensity, the amount of methane emitted per unit of natural gas to market, is a key performance metric used to measure the relationship between net gas production and methane emissions. The Oil and Gas Climate Initiative (OGCI) has set a methane intensity target of "well below" 0.20% by 2025. After increasing to 0.24% in 2018, methane intensity fell below the OGCI target to 0.17% in 2020. As predicted in the NSTA's 2022 Emissions Monitoring Report, in 2021 the value rose slightly to 0.19%. The NSTA estimates methane intensity to have decreased to 0.15% in 2022 (see Figure 13). This is due to a slight fall in methane emissions and an increase in net gas production from 2021.

Figure 12: Upstream oil and gas methane intensity per year, 2016 to 2022 (source: DESNZ and NAEI)



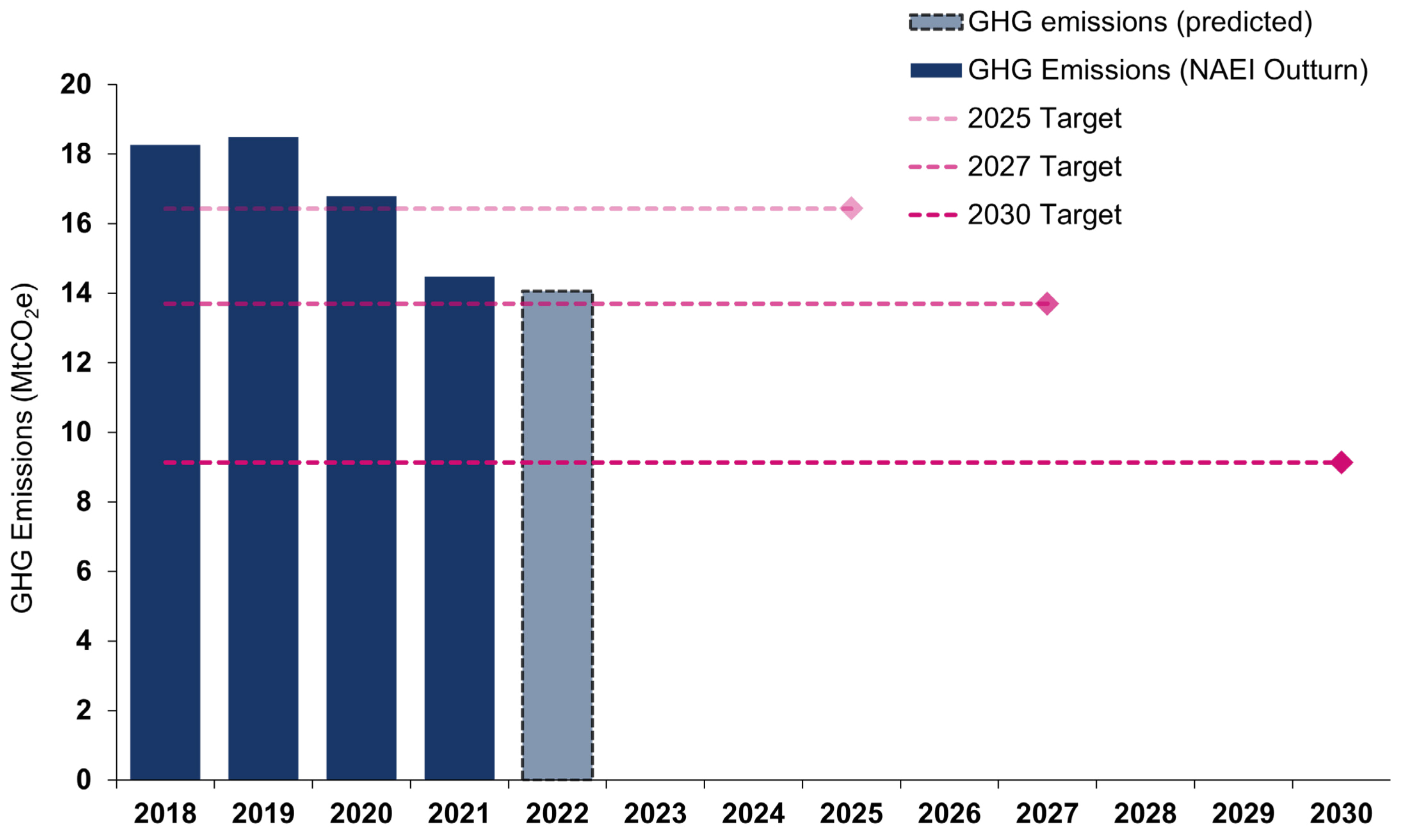
1.6 Progress towards emissions reduction targets

The NSTD established emission reduction targets for the UK upstream oil and gas industry. The targets commit industry to achieve the following reductions against a 2018 baseline: 10% by 2025, 25% by 2027 and 50% by 2030.

While NAEI data for 2022 will not be published until 2024, it is possible to estimate the industry's 2022 emissions with a high degree of confidence using other existing data sources such as the EEMS and the UK Emissions Trading Scheme (ETS) datasets. Both EEMS and ETS data shows that upstream GHG emissions saw a minor fall of between 3% and 5% between 2021 and 2022.

Using this data, the NSTA estimates a decrease in upstream oil and gas GHG emissions of 3% from 2021 to 2022 resulting in an overall reduction relative to 2018 of 23% (see Figure 13). This shows that the industry has already exceeded the 2025 target and is well on track to meet the 2027 target. Significant progress is though required to achieve a 50% reduction by 2030.

Figure 13: Progress of the UK upstream oil and gas against the NSTD targets (source: NAEI, EEMS, ETS)



2. Business as usual projection of UK upstream oil and gas emissions: 2023 update

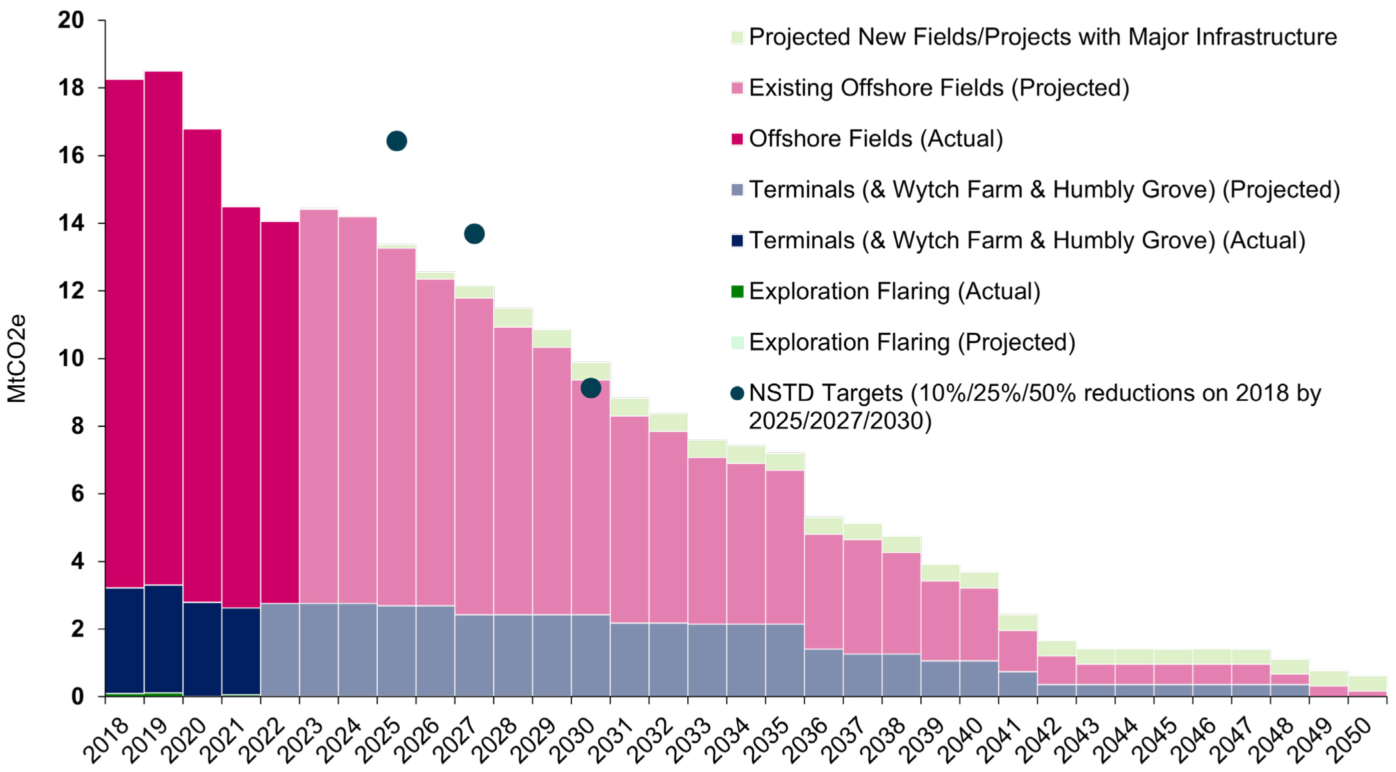
2.1 No further emissions abatement business as usual (BAU) projection

The NSTA published its first BAU emissions projection in 2021 to create a benchmark from which to measure the basin's progress towards achieving the NSTD targets – and to measure the impact of abatement initiatives. This projection is not a central estimate but instead a no further abatement baseline from which to measure the effectiveness of different abatement scenarios. These projections have been updated below to reflect the most up-to-date assessment of future emissions (see Figure 14).

The BAU projection:

- Assumes continued production from existing installations without any further proactive abatement activities.
- Does not assume abatement from zero routine flaring or venting (see section 3.2 for details).
- Assumes production from most new projects that the NSTA is currently regulating is not decarbonised, but does assume that any currently unknown future production installations will be designed to minimise GHG emissions in line with the NSTA guidance and expectations.

Figure 14: Outturn and projected GHG emissions – BAU i.e. without additional decarbonisation/abatement projects (source: NAEI, EEMS, ETS, NSTA)



Following an estimated 3% decrease in 2022, the NSTA BAU projection suggests upstream emissions will experience a small rise in 2023, before falling again but at a slower rate than recent years (projecting a 1% fall from 2023 to 2024), if there is no further abatement. Compared with the projection presented in the 2022 Emissions Monitoring Report, this profile is lower in the short term, with both the 2025 and 2027 NSTD targets now expected to be met by wider margins. In the medium term to long term however (late 2020s onwards), the profile follows the previous projection more closely and in the 2030s, is higher. As shown with the NSTA's previous two BAU projections, the 2030 NSTD target is not expected to be met without the implementation of further abatement initiatives or changes to cessation of production (CoP).

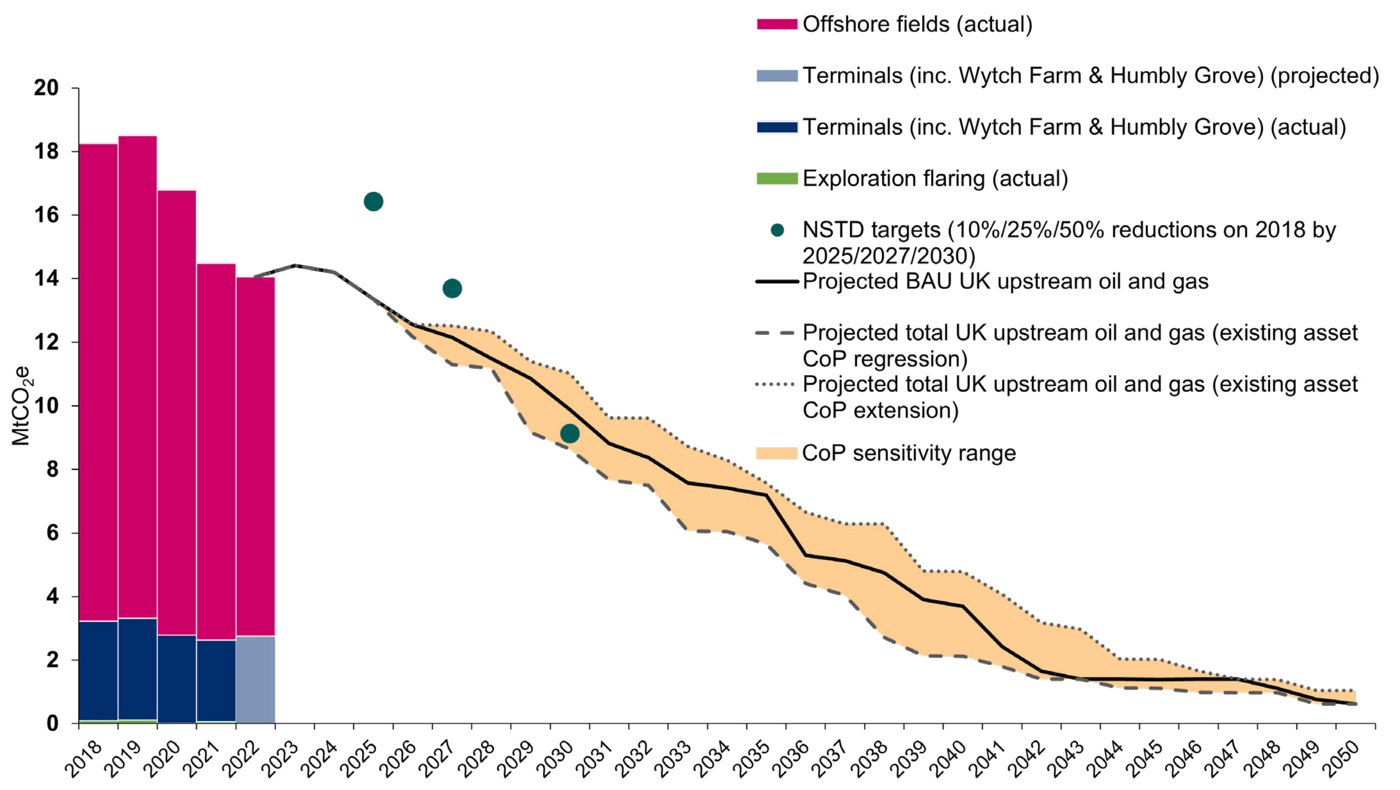
Meeting the NSTD targets is the minimum that the NSTA expects from industry, which must make a sustained effort to surpass them. Committing resource and capital to decarbonisation projects in the coming years is crucial to ensure that energy efficiency savings, further flaring and venting reductions and electrification of equipment deliver the required GHG emissions savings from the mid-2020s onwards.

2.2 BAU projection sensitivities

One of the key assumptions underpinning the NSTA's GHG emissions projection is a set of dates identifying when each offshore installation will stop producing oil and gas. These assumed points in time are referred to as cessation of production (CoP) dates. These dates are not fixed and can move forward and backward in time depending on asset specific economics and other factors. Varying the CoP date input assumptions significantly affects the output projection.

Figure 15 shows the modelled effect of extending or regressing asset CoPs relative to the current year. See Annex E for an explanation of this method. In 2030 there is a roughly an 11% range around the business as usual scenario due to varying CoP dates. It should be noted that while this modelling shows that the 2030 target could be met by bringing forward CoP dates (as illustrated by the "CoP regression" scenario outlined in Figure 15), there would be a consequential impact on oil and gas production, potentially in the region of 100 million barrels of oil equivalent between 2023 and 2030. This would be roughly equivalent to 3% of the UK's projected oil and net gas production over the same time period. That marginal production would have a GHG intensity of 47 $kgCO_2e$/boe, more than double the current offshore average.

Figure 15: Annual/projected GHG emissions – sensitivity of BAU projection to CoP date changes (source: NAEI, EEMS, ETS, NSTA)



3. Potential abatement opportunities

3.1 Offshore electrification deployment scenarios

In 2022, an estimated 79% of all offshore upstream oil and gas industry GHG emissions were the result of the combustion of either natural gas or diesel for fuel. Industry has been working for several years now to develop options for replacing natural gas and diesel with electricity as the main source of energy to power offshore operations. The source of this electricity could be from the UK grid or offshore renewable sources, both of which yield lower emissions per unit of energy delivered than current power generation at extraction sites.

In its 2022 report, the NSTA produced low, central and high case scenarios, which explored the potential emissions abatement on the UKCS via electrification of offshore facilities. As the challenges and benefits of platform and vessel electrification become clearer, these technical scenarios (i.e. not factoring in commercial viability) have been updated to take account of:

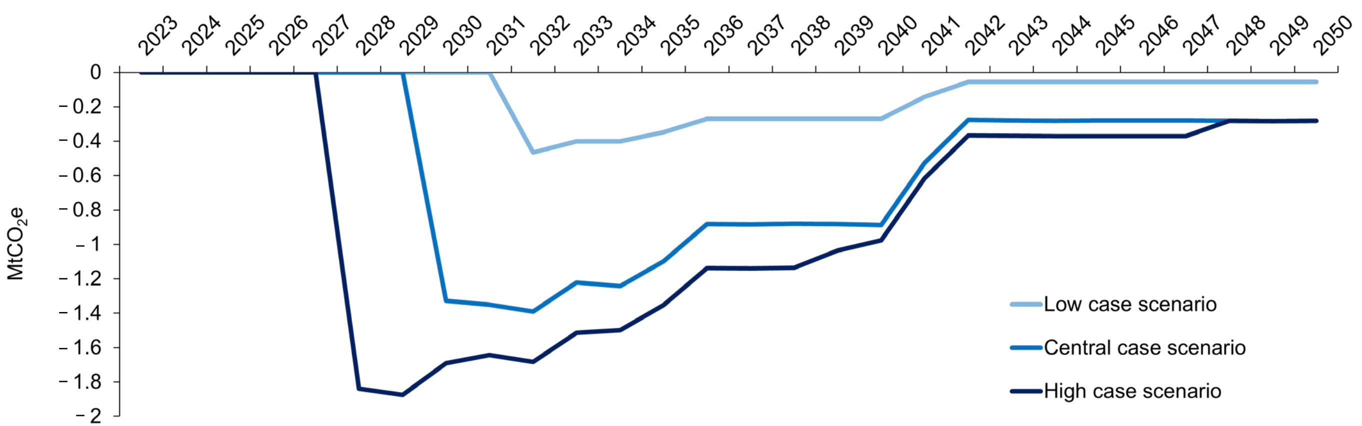
1) Better understanding of the scope of the offshore facilities that could be electrified.
2) Revised emissions for installations based on the BAU emissions projections.
3) Updated first-power assumptions for abatement savings.
4) Updated estimates of percentage reduction in emissions for partial and full electrification scenarios.
5) Updated forecasts of UK electricity grid emissions factors for scope 2 emissions calculations.

In this updated modelling:

- The low case assumes that seven assets are partially electrified in 2032.
- The central case assumes that eight assets are fully electrified in 2030.
- The high case assumes that nine assets are fully electrified, and eight assets are partially electrified in 2028.
- The low case does not assume greenfield electrification, but the central and high cases do.

Figure 16 shows the abatement profiles of the low, central and high technical deployment scenarios. The total cumulative abatement from the revised central case from 2030 to 2050 is estimated at 15 $MtCO_2e$. The high case assumes that all regulatory and economic enablers are realised for first power to be achieved by 2028. Estimates have changed compared to the 2022 Emissions Monitoring Report mainly due to better understanding of facilities considered for electrification projects, first power dates and overall abatement potential for full versus partial electrification based on assessments from industry and the NSTA.

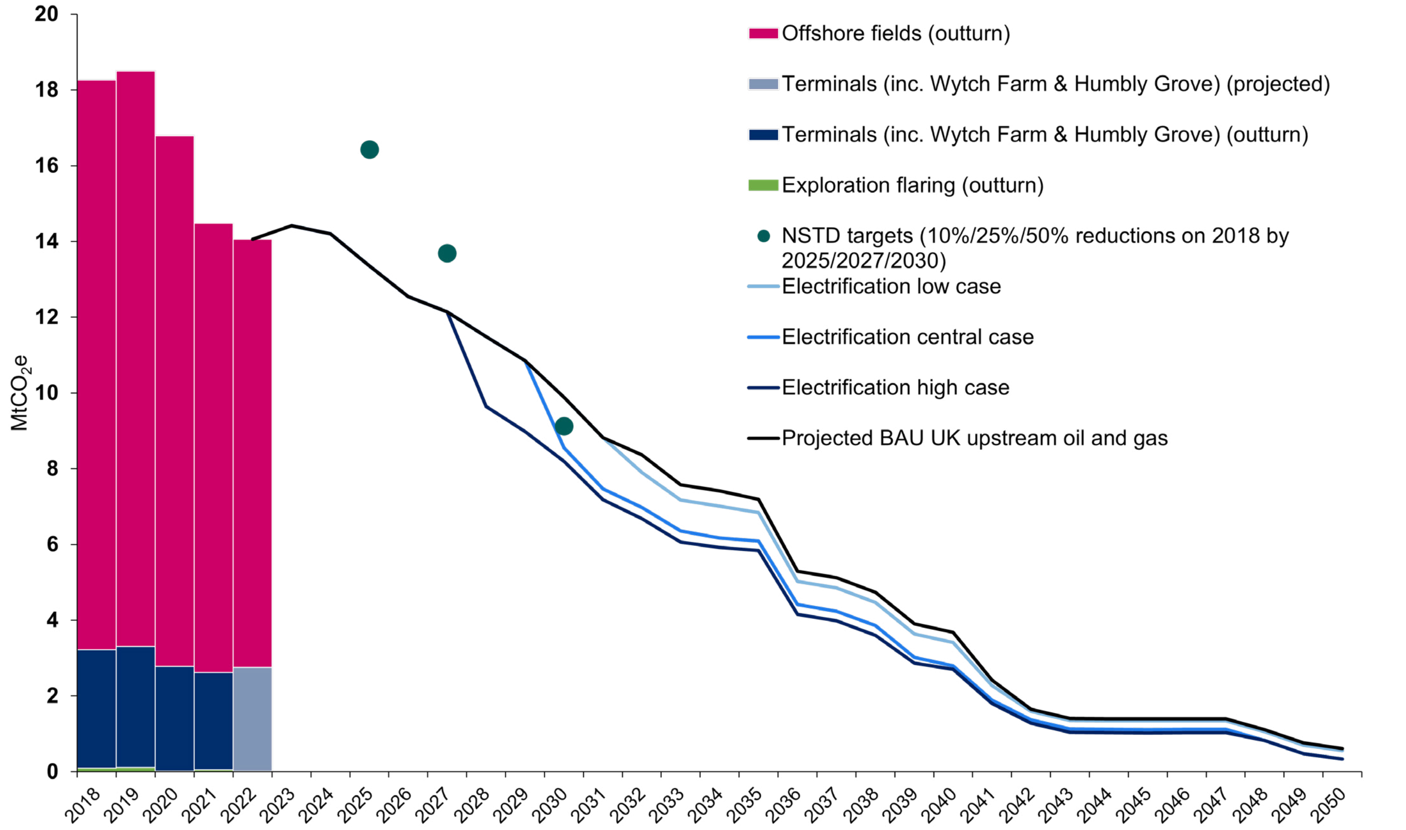
Figure 16: Annual estimated GHG emissions abatement from offshore electrification technical deployment scenarios, 2021–2050 (source: EEMS, NSTA)



These projections carry a high degree of uncertainty and technical assessments of emissions abatement. Economic or regulatory factors may downgrade these assessments. The uncertainty of abatement post-2040 is particularly high given the lack of clarity surrounding greenfield electrification projects.

The impact of emissions abatement from electrification on the achievement of the NSTD targets can be seen by setting the estimated technical GHG emissions abatement scenarios against the BAU emissions projection from the previous section, as shown in Figure 17.

Figure 17: Technical projections of UK upstream oil and gas GHG emissions: BAU emissions projection and electrification abatement scenarios, 2018–2050 (source: NAEI, ETS, EEMS, NSTA)



The five-year range on the date of first power between the three scenarios (2028 to 2032) greatly influences the effectiveness of electrification as a tool for offshore emissions reduction. The total savings from the low case are significantly below the central and high cases, at four times less and six times less respectively. If first power can, be achieved by 2028, the potential savings are substantial, with the high case delivering an additional 4.1 $MtCO_2e$ relative to the central case between 2028 and 2030. In the high case, electrification has the potential to contribute to a reduction in the industry's total emissions of nearly 60% by 2030 relative to 2018.

Electrification remains an important contributor to the achievement of the 2030 NSTD target. At a minimum, the central case is required. This means that the industry cannot afford to let plans slip and must focus on punctual delivery of these significant emissions reduction projects to realise their full potential.

As well as reducing emissions at the production site, electrification has the potential to bolster energy security through increased production of net gas to the UK which would have otherwise been combusted offshore. In the modelled central case scenario between 2030 and 2050, an estimated 24% of offshore fuel gas demand would be eliminated by electrification.

As with the BAU emissions projection, it is important to note that the abatement potential estimated in the above technical scenarios is not a forecast and should not be used as such. The scenarios are based on the NSTA's best understanding of the scope of projects that could be electrified and makes assumptions that strive to capture abatement from a range of deployment options. In this sense, the technical abatement scenarios are subject to high levels of uncertainty.

3.2 Implementation of zero routine flaring and venting

While positive progress has been made in reducing flaring activity from the UK upstream oil and gas industry (a 48% reduction was achieved between 2018 and 2022), flaring still accounts for 16% of total upstream GHG emissions. This makes flaring, after power generation, the most important area for emissions reduction. Unlike power generation, flaring and venting are responsible for significant methane emissions, which makes it even more important that these activities are reduced or eliminated in the short term.

The NSTA guidance establishes that:

- Zero routine flaring and venting (ZRFV) will be implemented for all assets by 2030 at the latest.
- All new oil and gas projects should be planned and developed based on ZRFV principles.

Routine, or Category A flaring and venting (as the NSTA guidance defines it) comprises roughly half of all current flaring and venting practices, with non-routine, or Category B and C flaring and venting constituting the remainder. Therefore, no routine flaring or venting by 2030 has the potential to significantly reduce GHG emissions from these sources. As well as eliminating GHG emissions from routine flaring and venting, the NSTA expects industry to reduce as much as reasonably practicable non-routine flaring and venting GHG emissions.

The NSTA has updated its estimate of emissions reduction from implementation of zero routine flaring through modelling the implementation of zero routine venting. Projections are based on estimates of future emissions from flaring and venting provided by operators through the UK Stewardship Survey, along with current data for routine flaring and venting, sourced from

NSTA consents applications (see Annex G for the detailed methodology). The model has used a tapering approach to build up to the savings calculated to be realised in 2030.

Figure 18 displays the estimated annual emissions reduction via ZRFV implementation. The initiative is expected to reduce emissions by nearly 3 $MtCO_2e$ between 2025 and 2050 with 64% coming from routine flaring elimination and 36% from routine venting elimination. 2030 sees the peak of the abatement as projects are carried out leading up to this year. Following this, declining baseline flaring and venting rates and facility cessation of production leads to a decrease in abatement. Figure 19 illustrates how this reduction would affect the overall flaring and venting emissions projection.

Figure 18: Annual estimated GHG emissions abatement relative to the baseline scenario from the implementation of zero routine flaring and venting from 2030 (source: NSTA)

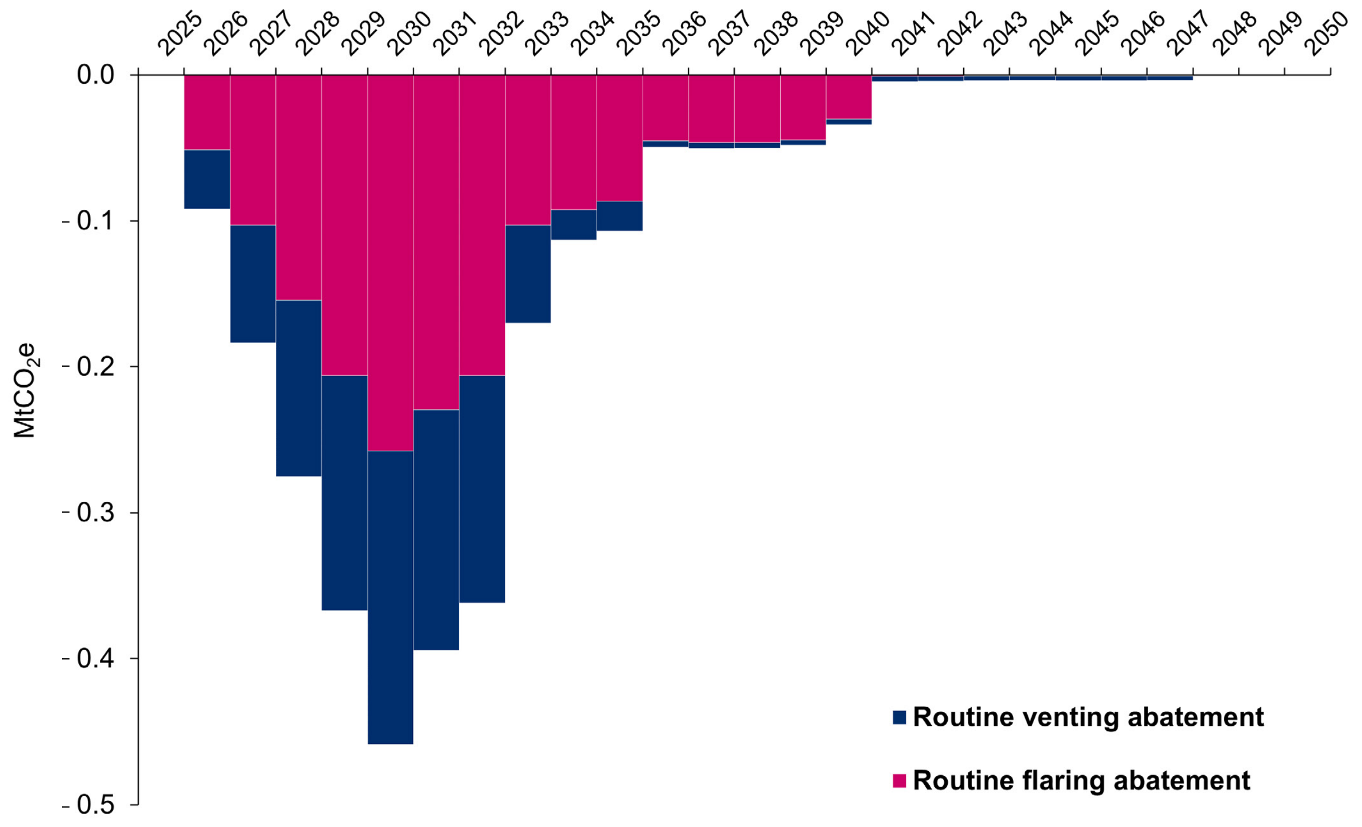
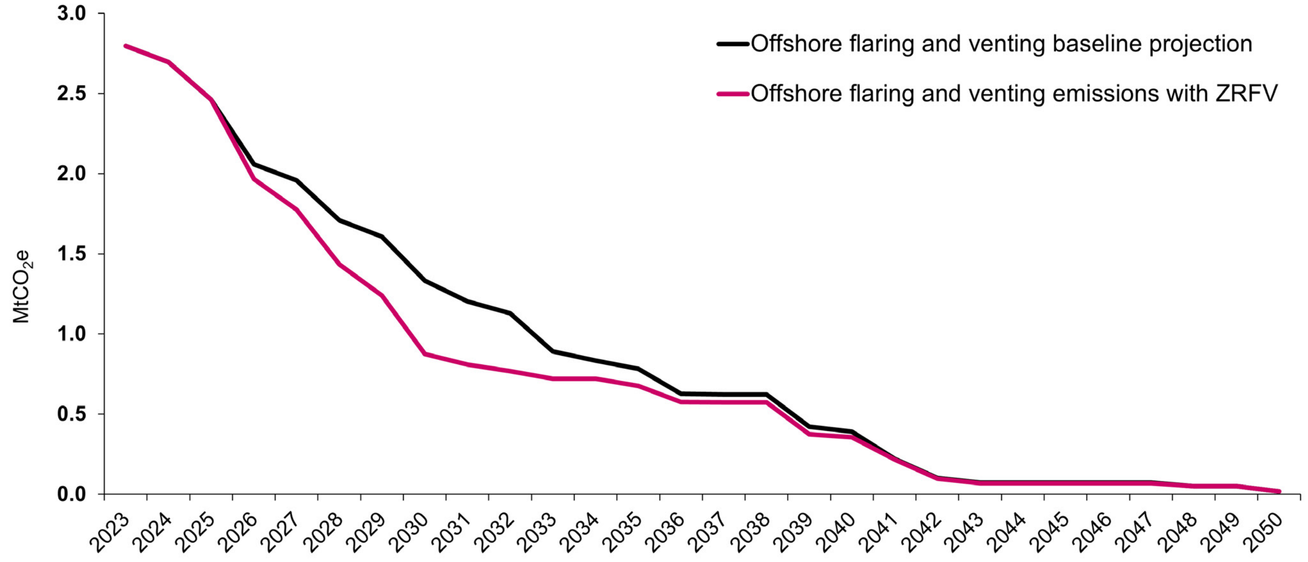


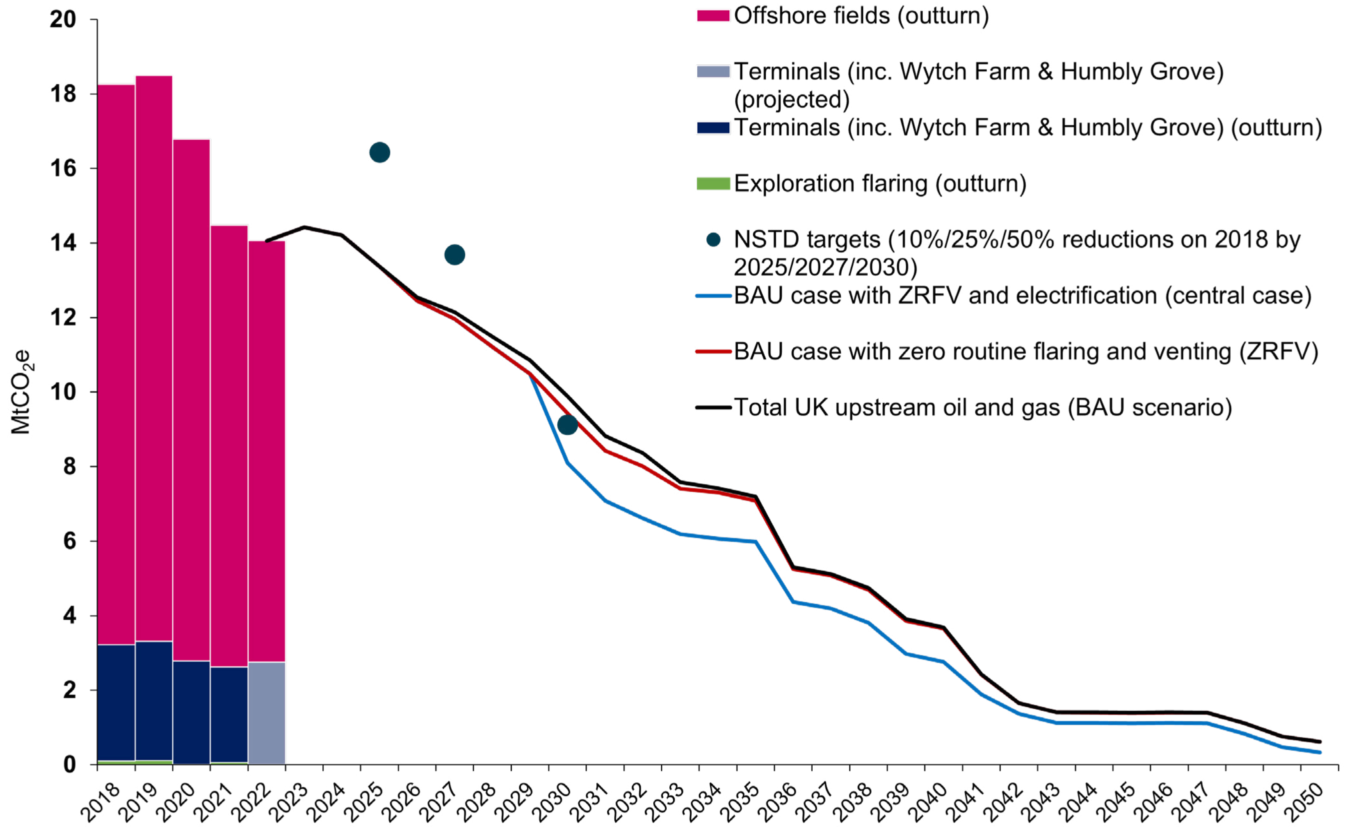
Figure 19: Technical projection of UK offshore upstream oil and gas flaring and venting emissions: baseline and ZRFV implementation (source: NAEI, EEMS, NSTA)



3.3 Combined abatement

The combined potential abatement of offshore asset electrification and zero routine flaring and venting is displayed in Figure 20. Full achievement of ZRFV and complete implementation of the central case electrification scenario by 2030 could see an up to 60% reduction on 2018.

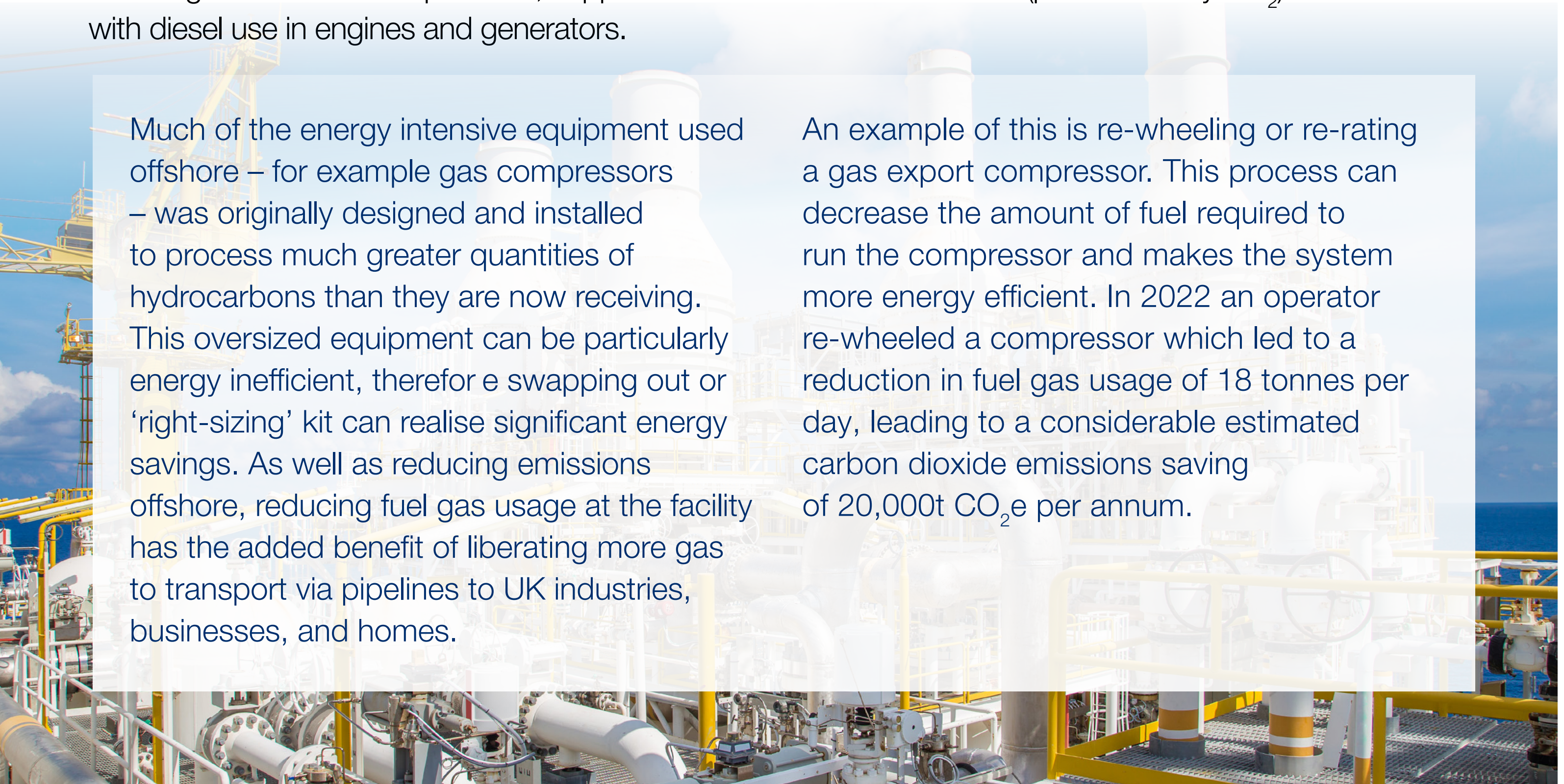
Figure 20: Technical projections of UK upstream oil and gas GHG emissions: BAU emissions projection and abatement scenarios, 2018–2050 (source: NAEI, ETS, EEMS, NSTA)



3.4 Abatement through energy efficiency

To date, UKCS oil and gas production facilities have met their electrical power and mechanical drive demands by combusting natural gas in gas turbine generators or compressors, supplemented with diesel use in engines and generators.

Due to this reliance on fossil fuels to run operations, any reduction in energy consumption to power offshore equipment will result in lower GHG emissions (predominantly CO_2).



Much of the energy intensive equipment used offshore – for example gas compressors – was originally designed and installed to process much greater quantities of hydrocarbons than they are now receiving. This oversized equipment can be particularly energy inefficient, therefor e swapping out or ‘right-sizing’ kit can realise significant energy savings. As well as reducing emissions offshore, reducing fuel gas usage at the facility has the added benefit of liberating more gas to transport via pipelines to UK industries, businesses, and homes.

An example of this is re-wheeling or re-rating a gas export compressor. This process can decrease the amount of fuel required to run the compressor and makes the system more energy efficient. In 2022 an operator re-wheeled a compressor which led to a reduction in fuel gas usage of 18 tonnes per day, leading to a considerable estimated carbon dioxide emissions saving of 20,000t CO_2e per annum.

To give an estimate of the emissions reduction prize from decreasing natural gas and diesel usage offshore, Figure 21 shows the potential emissions abatement from facilities which are expected to continue being powered by fossil fuel combustion from just a 5% reduction in energy usage between 2023 and 2030.

Figure 21: Illustrative emissions abatement at different energy saving levels for non-electrified assets (source: EEMS, NSTA)

Energy saving (relative to 2020)	Average annual GHG saving 2023–2030	Cumulative GHG saving 2023–2030
5%	0.2 Mt CO_2e	2.0 Mt CO_2e
10%	0.5 Mt CO_2e	3.7 Mt CO_2e

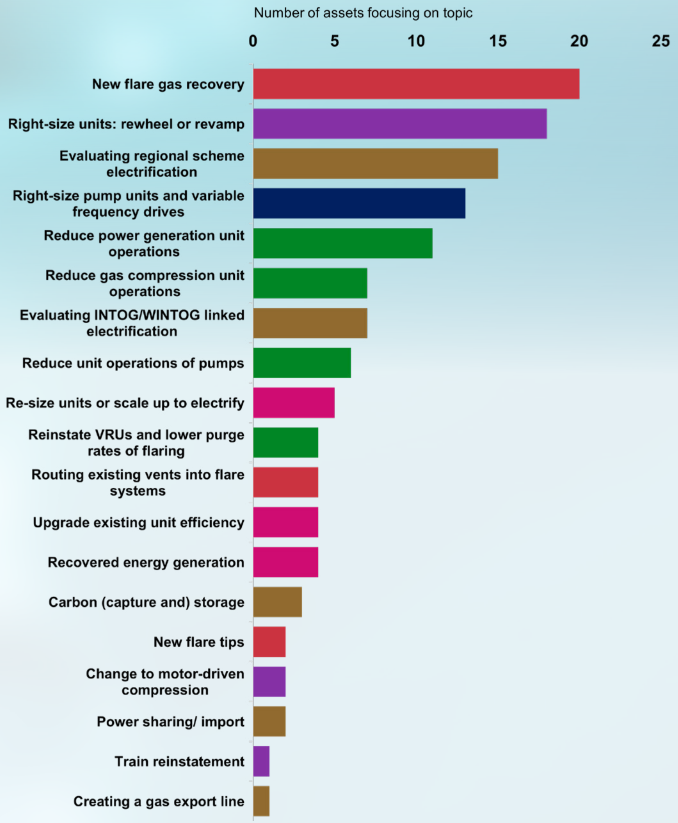
3.5 Emission Reduction Action Plans

The NSTA, via Stewardship Expectation 11 (Net Zero), outlined its expectation that operators develop, implement and maintain asset and/or infrastructure hubs GHG Emission Reduction Action Plans (ERAPs).

To date, the NSTA has received and analysed 65 ERAPs. These documents detail the current emissions footprint of the respective facility/facilities and highlight opportunities to reduce emissions. The NSTA has reviewed all the submitted documents and has categorised the decarbonisation pathways operators are exploring.

Figure 22 shows that at least half of all ERAPs outline plans to optimise their existing operations and to modify their flare and/or vent systems. Analysing ERAPs by individual assets (some ERAP documents cover several assets) shows that the most explored emission reduction lever is the implementation of new flare gas recovery (FGR) which will aid in achieving zero routine flaring. After FGR, right-sizing compression units and electrification schemes were the next most reported focus areas. NSTA modelling (see previous section) shows that both project types – particularly electrification – have significant potential to abate UK upstream oil and gas GHG emissions.

Figure 22: ERAP decarbonisation focus areas (source: NSTA)



Abatement pathways groups
(% of ERAPs covering topic):

- **66%** Optimise existing operations
- **52%** Modifying flare/vent systems
- **45%** Major infrastructure projects
- **32%** Modifying gas compression
- **26%** Modifying power generation
- **26%** Modifying electrical power users

4. Emissions performance benchmarking

The NSTA tracks facility level emissions and relative performance between facilities on an annual basis. Benchmarking emissions is integral to the asset stewardship process and, as with other industry themes such as production efficiency or unit operating costs, helps to drive significant performance improvements.

Between 2021 and 2022 there were 113 offshore production facilities with emissions ranging from under 100 tonnes of CO_2e to 554 kt CO_2e per annum. 58% of these facilities decreased their emissions from 2021 and 2022 with a median reduction of 18% (see Figure 23). Excluding facilities experiencing cessation of production, an estimated 57 assets reduced their emissions – representing efforts made by 50% of the offshore inventory to decarbonise production.

48 facilities increased their emissions from 2021 to 2022, with five of these being new installations. Increases from the remaining 43 assets represent a correction from low levels experienced in 2021. Seven facilities did not report emissions in 2021 but did so in 2022.

Figure 23: Offshore facilities emissions change, 2021–2022 (source: NSTA)

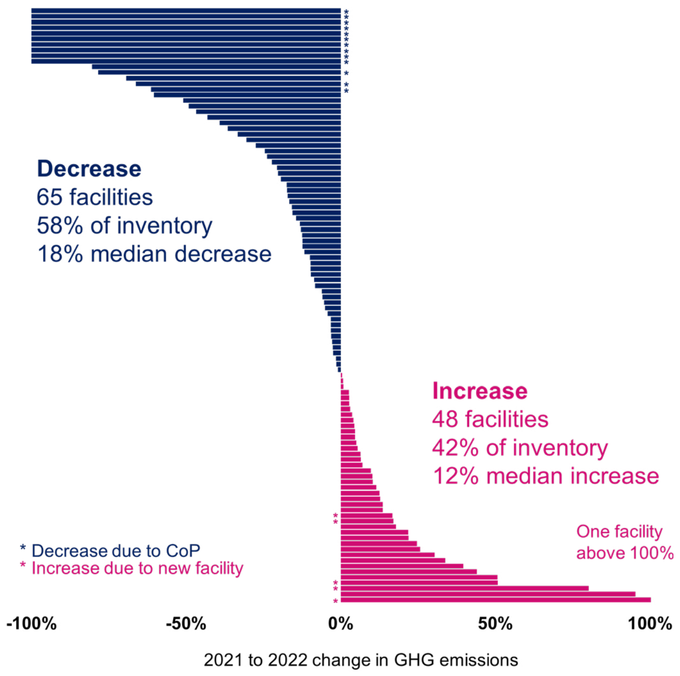
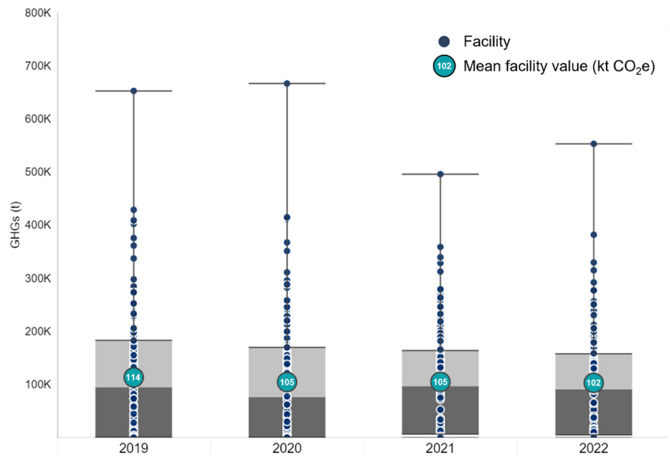


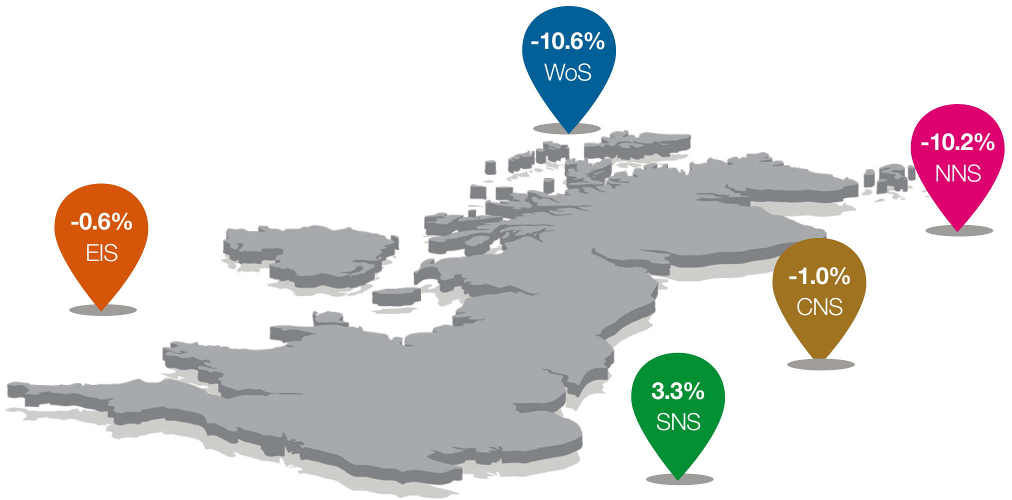
Figure 24 shows the distribution of offshore facility emissions between 2019 and 2022. In 2022 the average facility emitted 103 kt CO_2e, slightly down from 105 kt CO_2e in 2021. There are signs of the big emitters generally reducing their emissions over time as the 75th percentile value has fallen year on year from 2019 to 2022, from 184 kt CO_2e to 158 kt CO_2e respectively.

Figure 24: Offshore facilities CO_2e emissions distribution, 2019–2022 (source: EEMS)



Facility level change in GHG emissions between 2021 and 2022 varied considerably across the different geographical areas of the UKCS (Figure 25). While facilities in the East Irish Sea (EIS) and Central North Sea (CNS) showed small reductions in emissions between 2021 and 2022, Northern North Sea (NNS) and West of Shetland (WoS) areas experienced more significant reductions, with these heavily influenced by the permanent shutdown of a couple of large emitters. In contrast, the Southern North Sea (SNS) area shows a small increase in emissions between 2021 and 2022. In the SNS, five facilities comprise 88% of the emissions, and with these five facilities emitting more in 2022, this resulted in a minor increase for the region.

Figure 25: Regional breakdown of GHG emissions reductions in 2022 (source: EEMS)



4.1 Carbon and GHG intensity

Assessing the GHG emissions performance of offshore facilities by absolute emissions is challenging due to the differences in size of platforms, lifespan, operations handling and subsurface factors such as fluid and gas composition.

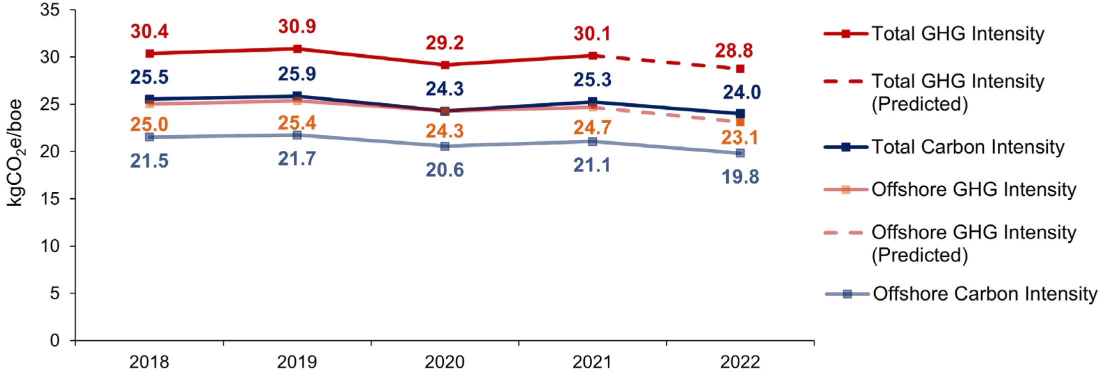
For this reason, it is common practice to use an intensity measure of emissions to compare performance. This is a measure of the emissions associated with the production of each barrel of oil equivalent (boe). This report uses two different intensity measures: GHG intensity and carbon intensity. See Annex H for an explanation of these terms and how they are calculated.

Figure 26 shows the range of intensity measures for UK upstream oil and gas production. Total GHG or carbon intensity, also includes emissions from terminals as well as from offshore fields. The chart illustrates that due to a continued decrease in CO_2 and GHG emissions in 2022 and a slight increase in total oil and gas production, all measures of intensity fell or are predicted to have fallen in 2022.

In 2022 total carbon intensity fell to 24.0 $kgCO_2$/boe while for offshore facilities only this figure was 19.8 $kgCO_2$/boe.

Although NAEI data shows that in 2021, the total upstream GHG intensity rose to 30.1 $kgCO_2e$/boe, the NSTA expects this to have declined to around 28.8 $kgCO_2e$/boe in 2022.

Figure 26: Offshore and total (offshore plus terminals) industry carbon and GHG intensity, 2018–2022 (sources: NAEI, NSTA, EU ETS, UK ETS)



4.2 Carbon intensity of offshore assets

Performance of carbon intensity – i.e. CO_2 emitted per barrel of oil equivalent produced – can vary significantly between UKCS assets due to the size, age and type of the installation.

Using verified UK ETS data combined with NSTA production data, Figure 27 shows that on average, larger and older assets have higher carbon intensities than newer, smaller assets.

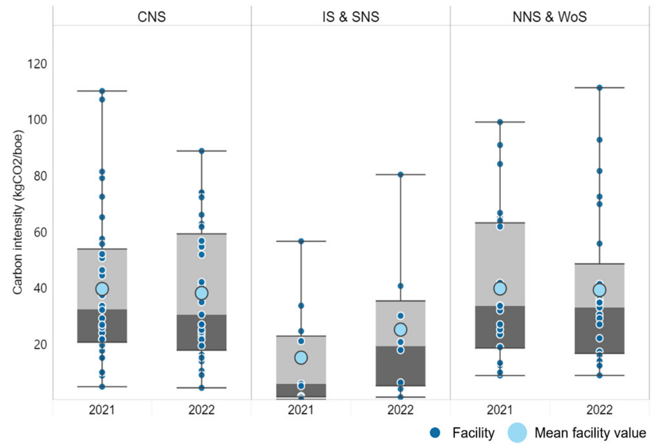
There are also regional differences. In 2022, the EIS had the highest carbon intensity of all UKCS regions at 33 $kgCO_2$/boe, followed by the NNS (31), CNS (19), WoS (13), and SNS (7). Figure 28 details the distribution of facility level carbon intensity for each UKCS region for 2021 and 2022.

Detailed analysis on carbon intensity and GHG intensity is available in the NSTA's interactive emissions dashboard that accompanies this report.

Figure 27: 2022 carbon intensity breakdown by installation type and age (source: ETS, NSTA)

Carbon Intensity ($kgCO_2$/boe)		Facility type		
		Small Platform	Floating	Large Platform
Facility Age	<10 Years	7	15	11
	11-25 Years	26	39	24
	>25 Years	27	33	54

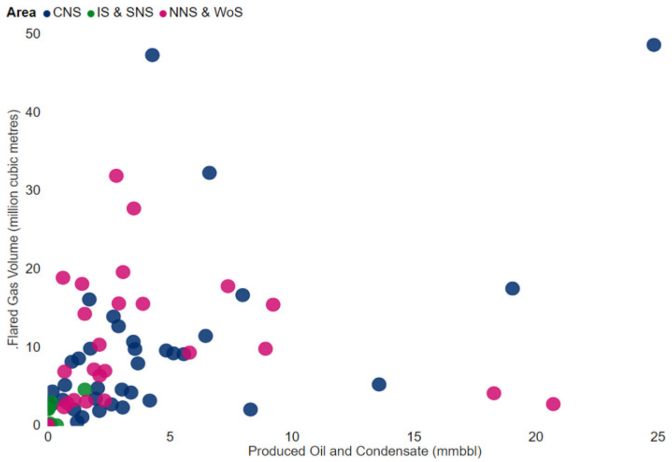
Figure 28: UKCS distribution of carbon intensity by region, 2021–2022 (source: ETS, NSTA)



4.3 Flaring and venting benchmarking

Flaring and venting volumes and gas composition vary throughout the UKCS. Reservoir fluids and topside processes are among the main determinants behind the differences. As shown in Figure 29, there is generally a weak positive correlation between the volume of flared gas and oil production.

Figure 29: Volumes of flared gas, compared with oil production by UKCS area, 2022 (source: NSTA)

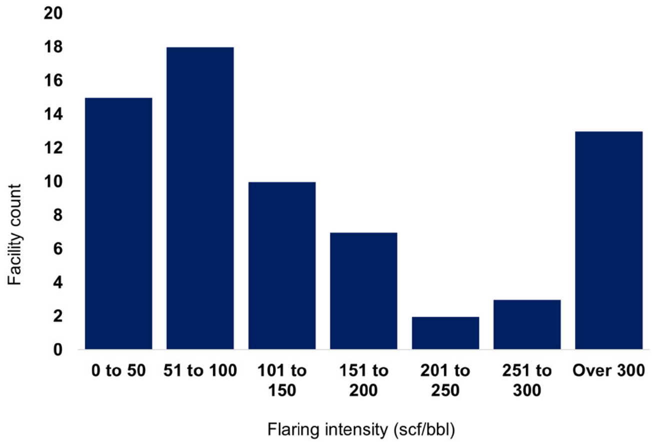


Generally, the CNS region shows larger volumes of gas flaring and oil production than elsewhere, however, the NNS and WoS regions have a wider spread of production and flaring volumes. The EIS and SNS regions on the other hand, flare and produce comparatively less than the other regions.

The ratio of flared gas to produced oil – or the flaring intensity – can vary significantly between facilities. In 2022, the UKCS flaring intensity was 85 standard cubic feet of gas flared per bbl of oil produced (scf/bbl), down 6% relative to 2021 levels of 90 scf/bbl. Data for the first half of 2023 show that flaring intensity has remained at 85 scf/bbl.

Figure 30 illustrates that while nearly half of all facilities have a lower flaring intensity than 100 scf/bbl, a fifth still have a flaring intensity of over 300 scf/bbl, indicating that there is further room for improvement of flaring performance.

Figure 30: Histogram of facility level flaring intensity in 2022 (source: NSTA)



Flaring intensity can be explored in more detail in the NSTA emissions benchmarking dashboard that accompanies this report.

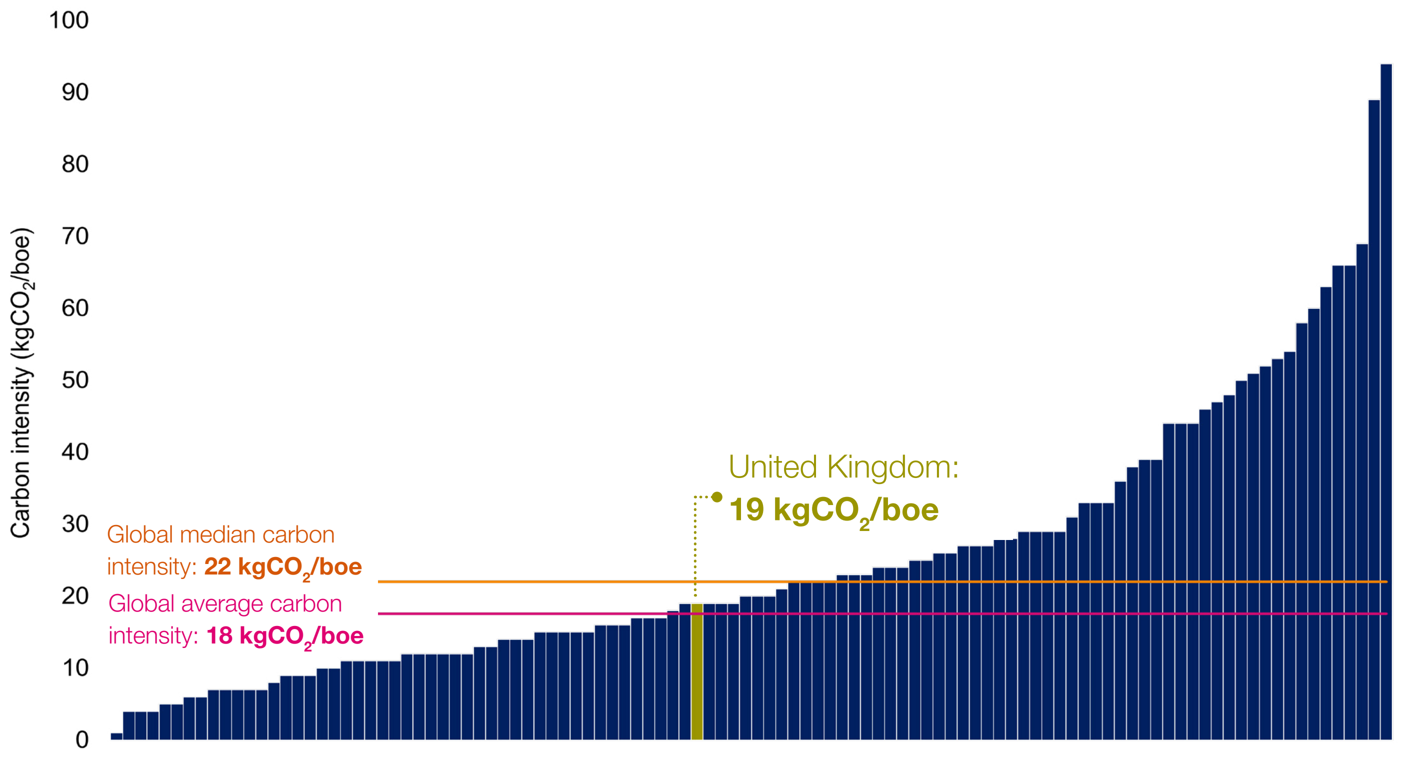
5. International benchmarking of UKCS carbon intensity

In 2023 the NSTA updated its gas footprint analysis (see page 55) and concluded the production, processing and transportation footprint of domestic gas is a quarter that of imported LNG.

Using data sourced from Rystad Energy, looking only at production emissions, a comparison of UK carbon intensity with all other hydrocarbon producing countries is shown in Figure 31.

According to Rystad Energy's data and methodology, the UK's carbon intensity has decreased from 21 $kgCO_2$/boe to 19 $kgCO_2$/boe between 2021 and 2022. 19 $kgCO_2$/boe in 2022 places the UK slightly lower than the 2022 global median value of 22 $kgCO_2$/boe, and slightly above the global average of 17 $kgCO_2$/boe. This is heavily influenced by factors like age of basin, whether production in onshore or offshore, geology and so forth. While the UK's carbon intensity has fallen by 14% since 2019 (compared to a fall of 3% globally), there is still room for improvement in the UKCS.

Figure 31: Estimated country-level carbon intensity (flaring plus extraction intensity) and oil and gas production by country – global, 2022 (source: Rystad Energy)



Notes:

- Forty countries with a production value of zero excluded from the dataset.
- Carbon intensity figures detailed in Figure 31 for the UK and other countries exclude carbon dioxide emissions produced by onshore terminals, therefore the intensity figures relate solely to emissions generated at the oil or gas field.
- Carbon intensities at country level conceal the great extent of in-country variation in carbon intensity at field level. Some of this variation is related to the phase in the life cycle of each field, with late-life carbon intensity rising exponentially as production rates decline and cessation of production approaches.

5.1 Carbon intensity of UK natural gas imports

In July 2023, the NSTA published an assessment of the production-related carbon intensity of UK produced natural gas compared to imported gas. The findings were that while pipeline imports (primarily from Norway) were under half the intensity of domestically produced gas, imports of LNG from a variety of countries around the world were nearly four times as carbon intensive. This is in part due to the extremely energy intensive process of liquefying natural gas, which is required to transport the gas by ship to places out of reach of pipelines. With LNG comprising nearly a third of all UK gas supply in 2022 these findings show that producing natural gas in the UK assists with both domestic energy security and the wider international community's goals of reaching net zero emissions.

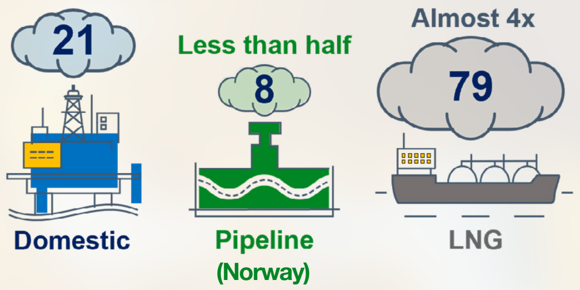
This factsheet summarises a comparison of carbon intensity of the UK's domestic production to that of imported LNG and pipelined gas.

Given the lack of standardised monitoring, measurement and reporting of emissions across natural gas lifecycle stages and global sources, as well as uncertainties, all import emissions values are best estimates.

Carbon intensity of UK imported natural gas

At 21 $kgCO_2$/boe[1], the average carbon intensity[2] of UK gas production is lower than the average carbon intensity of all sources of natural gas imported to the UK (except pipeline imports from Norway).
The average carbon intensity of imported LNG is almost four times the carbon intensity of UK production.

Figure 32: 2022 average carbon intensity ($kgCO_2$/boe)



[1] All estimates of carbon dioxide emissions and carbon intensities are sourced from Rystad Energy's Gas and LNG trade emission analysis dashboard (July 2023).
[2] Carbon intensity = carbon dioxide (CO_2) emissions per barrel of oil equivalent (boe) produced.

UK gas supply mix and carbon dioxide emissions

In 2022, gas imports to the UK accounted for 63% of its natural gas supply. The UK helped to meet the surge in European LNG demand by increasing its LNG imports (by 74%) and then exporting the surplus supply to Europe through pipelines (240% increase from 2021).

Figure 33: UK 2019–2022 gas supply (mmboe)[3,4]

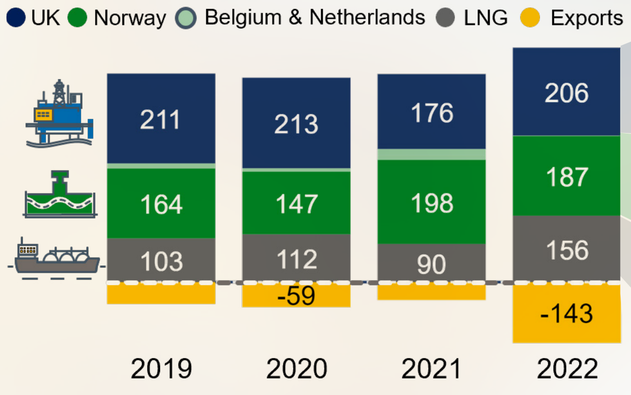
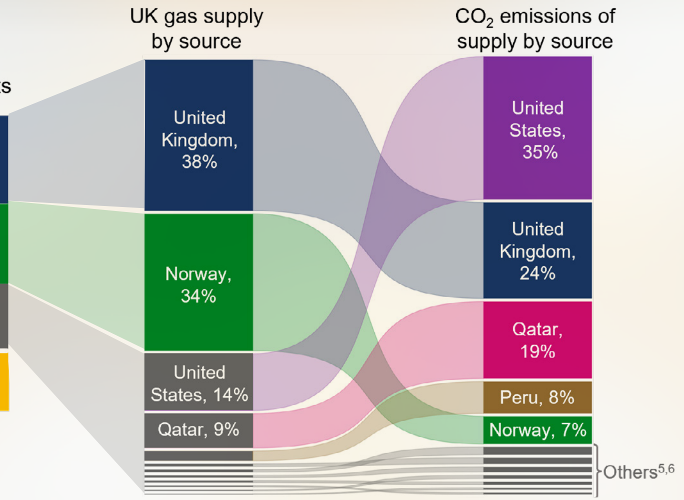


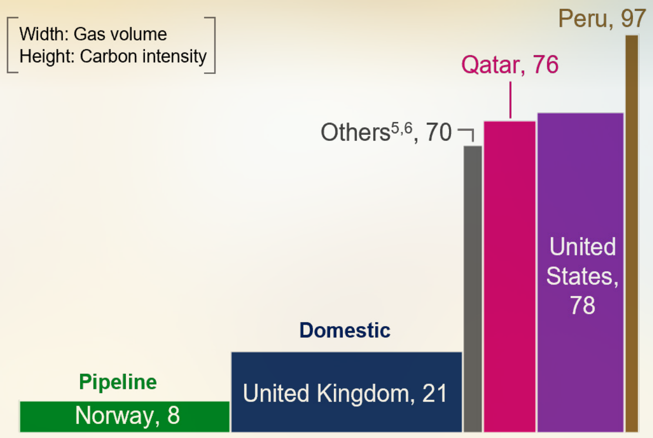
Figure 34: 2022 UK gas supply and emissions



[3] Gross supply. The UK is a net gas importer but seasonally exports significant gas volumes to the Republic of Ireland, Belgium and the Netherlands.
[4] Source: Department for Energy Security and Net Zero (DESNZ) Energy Trends: UK Gas. Assuming 1 boe = 5800 standard cubic feet of natural gas.
[5] Others: Countries with import volumes less than five million boe in 2022.
[6] Average intensity of grouped countries = Sum of emissions divided by sum of import volumes.

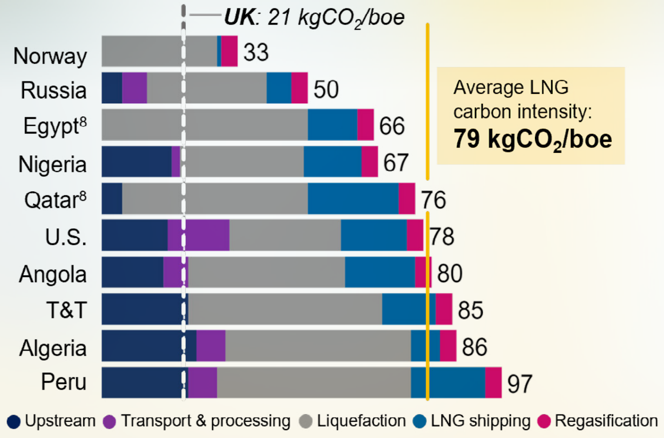
2022 UK gas supply carbon intensities

Figure 35: 2022 carbon intensity ($kgCO_2$/boe) by gas volume and by country



Others: Angola, Algeria, Nigeria, Russia, Trinidad and Tobago, Norway LNG and Egypt

Figure 36: 2022 UK LNG import carbon intensity ($kgCO_2$/boe) profile[7] by country



[7] The LNG value chain stages: upstream, transport & processing, liquefaction, LNG shipping and regasification.
[8] Egypt and Qatar's data is not disaggregated for all five LNG value chain stages.

- Natural gas imported via Belgium and the Netherlands is a mix of gas from Norway, Russia, Germany and France. In 2022, imports from Belgium and Netherlands made up only 1% of pipelined gas imports as the pipelines from Belgium and Netherlands were almost exclusively used to export gas to Europe between April and December.
- No LNG imports were received from Russia between April and December 2022. During Q1 2022, Russian LNG originated from the relatively new Arctic Yamal LNG plant.

6. Conclusions

Total emissions from UK upstream activities fell for the third consecutive year in 2022, as progress to ensure the UK's domestic oil and gas production is as clean as possible continued. Last year's 3% reduction contributed to a decrease of 23% between 2018 and 2022.

A large number of platforms had temporarily stopped producing in 2021 to allow maintenance programmes to be carried out while pipeline systems were bring upgraded. The resulting large drop in gas production was corrected in 2022 when both gas and combined oil and gas production increased.

Continued progress on emission reductions even as total production increased slightly was achieved thanks to a combination of factors, including the NSTA's robust and proactive approach to regulation and management, industry investment in technologies which reduce flaring, and initiatives to make equipment such as compressors more fuel efficient.

The latest data indicates that emissions may increase slightly in 2023 before falling again in 2024 and every year thereafter, until well into the 2040s. Though the general trend shows a slowdown in decline rates, the sector remains well on course to meet the interim NSTD emissions reduction targets of 10% by 2025 and 25% by 2027.

However, further abatement measures will be needed if industry is to achieve its goal of halving production emissions by 2030, against a 2018 baseline. Meeting the 50% target is the absolute minimum the NSTA expects from industry; it needs to be ambitious and aim to surpass it.

The NSTA will continue to hold industry to account on emissions by monitoring, tracking and benchmarking operators' performance, sharing best practice, and pressing licensees for progress on flaring reduction, energy efficiency and platform electrification schemes. The very low carbon intensity of gas imported from Norway via pipeline is a positive sign as it shows there is significant scope to make UK production cleaner.

Annex: Emissions Monitoring Report 2023 methodology

This document provides additional technical details and sources to accompany the analysis in the NSTA's 2023 Emissions Monitoring Report.

A. IPCC data – upstream oil and gas categories

GHG emissions from the UK upstream oil and gas industry can be extracted from the NAEI dataset using the following relevant Intergovernmental Panel on Climate Change (IPCC) categories:

1A1cii – Manufacture of solid fuels and other energy industries

Source	Fuel Group	Activity Name
Gas terminal – fuel combustion	Gaseous fuels	Natural gas
Gas terminal – fuel combustion	Petroleum	Gas oil
Oil terminal – fuel combustion	Gaseous fuels	Natural gas
Oil terminal – fuel combustion	Petroleum	Gas oil
Upstream gas production – fuel combustion	Gaseous fuels	Natural gas
Upstream gas production – fuel combustion	Petroleum	Gas oil
Upstream oil production – fuel combustion	Gaseous fuels	Natural gas
Upstream oil production – fuel combustion	Petroleum	Gas oil

1B2a1 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Onshore oil well exploration (conventional)	Other emissions	Number of wells per year
Upstream oil production – offshore well testing	Other emissions	Exploration drilling: amount of gas flared
Oil terminal – direct process	Other emissions	Non-fuel combustion
Oil terminal – other fugitives	Other emissions	Non-fuel combustion
Onshore oil production (conventional)	Other emissions	Crude oil
Petroleum processes	Other emissions	Oil production

Source	Fuel Group	Activity Name
Upstream oil production – fugitive emissions	Other emissions	Non-fuel combustion
Upstream oil production – direct process emissions	Other emissions	Non-fuel combustion

1B2a3 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Oil transport fugitives – pipelines (onshore)	Other emissions	Crude oil
Oil transport fugitives – road tankers	Other emissions	Crude oil
Upstream oil production –offshore oil loading	Other emissions	Crude oil
Upstream oil production – onshore oil loading	Other emissions	Crude oil

1B2a4 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Upstream oil production – oil terminal storage	Other emissions	Non-fuel combustion

1B2c1i – Upstream oil and gas – venting

Source	Fuel Group	Activity Name
Oil terminal – venting	Other emissions	Non-fuel combustion
Upstream oil production – venting	Other emissions	Non-fuel combustion

1B2c1ii – Upstream oil and gas – venting

Source	Fuel Group	Activity Name
Gas terminal – venting	Other emissions	Non-fuel combustion
Upstream gas production – venting	Other emissions	Non-fuel combustion

1B2c2i – Upstream oil and gas – flaring

Source	Fuel Group	Activity Name
Oil terminal – gas flaring	Other emissions	Non-fuel combustion
Onshore oil production – gas flaring	Other emissions	Non-fuel combustion
Upstream oil production – flaring	Other emissions	Non-fuel combustion

1B2c2ii - Upstream oil and gas - flaring

Source	Fuel Group	Activity Name
Gas terminal – gas flaring	Other emissions	Non-fuel combustion
Upstream gas production – flaring	Other emissions	Non-fuel combustion

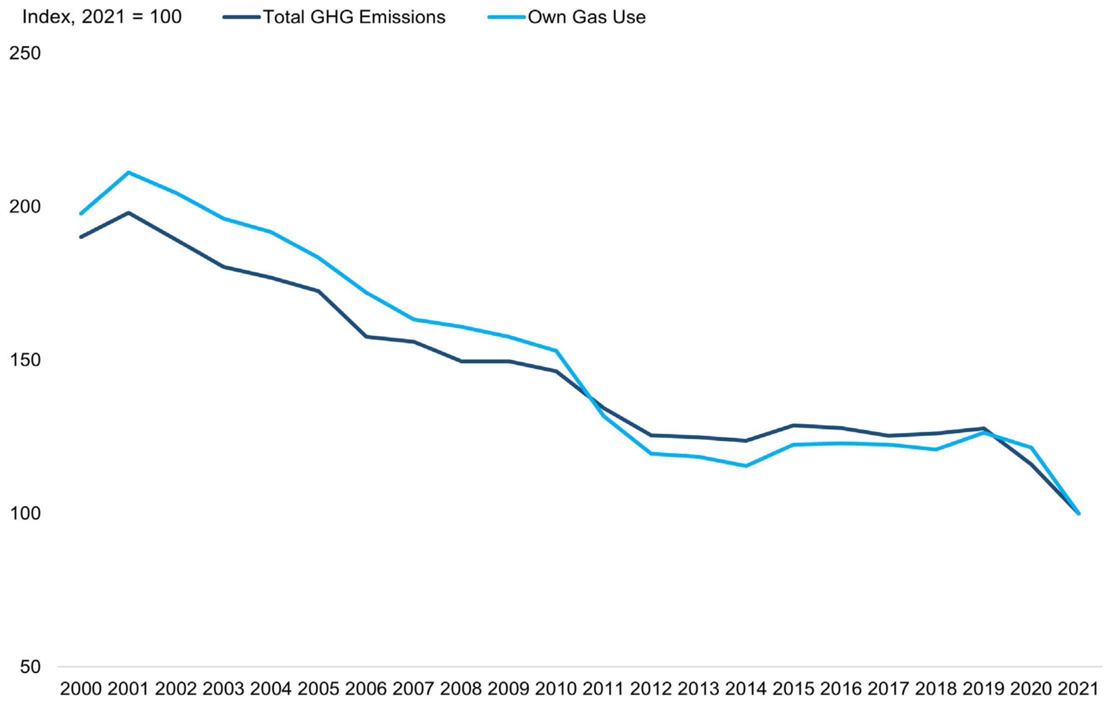
IPCC – NAEI data caveat

A caveat associated with using the NAEI dataset is that the total includes emissions from combined heat and power (CHP) plants adjacent to upstream facilities at Sullom Voe Terminal. The NSTA does not consider these facilities to be part of the UK upstream oil and gas industry. Unfortunately, these values can't be removed from the dataset. The total emissions from this facility are estimated to comprise a very small proportion of the total dataset.

B. Global warming potential factors

Non-carbon dioxide GHGs have been converted to carbon dioxide equivalent (CO_2e) units using global warming potential (GWP) factors presented in the IPCC's Fifth Assessment Report (AR5) (table 8.7, page 714). The GWP factors used are without inclusion of climate-carbon feedbacks (no cc fb) and over a 100-year timescale.

C. Relationship between total GHG emissions and offshore fuel gas usage



D. BAU emissions projections methodology

The NSTA has updated its bottom-up BAU projection of the sector's GHG emissions based on recent historical emissions data for all offshore installations using DSNZ EEMS data. The BAU assumes no further abatement. Expected cessation of production dates are based on assessments of recent UK Stewardship Survey (UKSS) data for each installation. An allowance has also been made for a small number of major new developments which would materially increase GHG emissions. Inclusion of a new field in this list is without prejudice to DESNZ or the NSTA granting consent to development.

For existing offshore installations which are expected to be in use after 2022 the NSTA has been guided by EEMS data for 2020 to 2022. For onshore terminals and Wytch Farm & Humbly Grove projections the NSTA has based this on verified CO_2 emissions for 2020 from the EU ETS and for 2021 and 2022 from the UK ETS with historic data for other GHGs for these facilities coming from the websites of the Environment Agency and the Scottish Environment Protection Agency.

Emissions from exploration flaring are assumed to decline at 5% a year starting from 2020 levels as reported in the NAEI.

Current projections reflect best estimates of future emissions on a baseline basis, that is, without decarbonisation measures such as platform electrification and elimination of routine flaring.

Major updates to the BAU emissions projections this year include:

- Baseline emissions for 2018 have been revised down owing to updates in NAEI data.
- Recently approved projects that were previously categorised as new fields have been moved into existing offshore fields. The result is a shift down in the projected new fields emissions compared to last year.
- Cessation of production dates have been updated to reflect information from the latest UKSS.
- Projected emissions for a small number of recent and new installations are based on operators' emissions forecasts collected in the UKSS and environmental statements for other developments.

It is important to note that the baseline emissions projections are not a forecast of upstream oil and gas GHG emissions and should not be used as such. The projections are based on an analytical approach that sets out to project historic data into the future. In this sense, the emissions projections are subject to high levels of uncertainty and are underpinned by the assumptions made on cessation of production dates and other relevant variables previously outlined.

E. Cessation of production date sensitivity modelling methodology

To model the effect of varying cessation of production (CoP) dates used within the baseline projection modelling (as displayed in Figure 15), the following method was employed:

- Take the operator reported CoP dates for each installation as reported in the UK Stewardship Survey and assign these into one of the following groups:
  - Present to 2025 – Group 1
  - 2026 to 2029 – Group 2
  - 2030 to 2034 – Group 3
  - 2035 to 2040 – Group 4
  - Post-2040 – Group 5
- For Group 1, assign a 0 year +/- sensitivity. For Group 2, assign a 1 year +/- sensitivity. For Group 3, assign a 2 year +/- sensitivity. For Group 4, assign a 3 year +/- sensitivity. For Group 5, assign a 4 year +/- sensitivity.
- Run the model assuming CoP extension (i.e. +1 year into the future for Group 2, etc.).
- Run the model assuming CoP regression (i.e. -1 year towards the present for Group 2, etc.).
- Display the calculated profiles against the original baseline projection.

F. Technical deployment scenarios for electrification abatement of oil and gas installations

The NSTA has produced a low, central and high case assessment of the sector's GHG technical abatement potential from the electrification of offshore facilities. This has been based on the following:

- A detailed list of installations being considered for electrification and whether the installation is estimated to be fully or partially electrified in any given scenario.
- Installation level power demand data calculated from data submitted to EEMS.
- Recent emissions histories for relevant installations and expected cessation of production dates based on latest UKSS data for each installation.
- Assumptions of 100% abatement of power generation emissions for a fully electrified installation and 35% abatement of power generation emissions for a partially electrified installation.
- Variables between each of the modelled cases are:
  - Installations in scope
  - Whether facilities are fully or partially electrified
  - First power year
- Scope 2 emissions (those emitted during the generation of imported electricity) have been factored into the abatement figures by:
  - Assuming partially electrified facilities source electricity from offshore wind, which has zero scope 2 emissions.
  - Assuming fully electrified facilities source all electricity from the UK electricity grid. A best estimate of facility future power demand has been combined with DESNZ published forecast UK electricity grid emission factors to calculate scope 2 emissions. These have been subtracted from the scope 1 abatement to state scope 1 abatement net of scope emissions.

Methodology updates to the technical deployment scenarios this year include:

- Installation cessation of production dates are assumed to be fixed and consistent with the baseline emissions projections.
- The high case assumes first power in 2028, the central case in 2030 and the low case in 2032 – for all brownfield assets.
- The list of potential installations and assets considered in the scenarios has been refined to reflect the most up-to-date data regarding electrification projects.

It is important to note that as with the BAU emissions projections the abatement potential estimated in the technical scenarios is not a forecast and should not be used as such. The scenarios are based on the NSTA's best understanding of the scope of projects that could be electrified and makes assumptions that are intended to capture a range of potential future deployment levels. In this sense, the technical abatement scenarios are subject to high levels of uncertainty.

G. Routine flaring and venting emissions abatement methodology

The NSTA has produced a projection of emissions abatement from the cessation of routine flaring and venting by 2030. The methodology for estimated abatement via zero-routine flaring and venting (ZRFV) by 2030 is:

- Using UKSS data, generate a list of facilities that expect to be flaring and/or venting after 2030.
- Calculate historic trends of routine flaring and venting for these facilities using NSTA flaring consents application data.
- Using this, assign each facility a predicted proportion of routine flaring/venting going forward.
- Combine the UKSS profiles, the filtered facility list and the predicted proportion of routine flare/vent to produce a projection of routine flaring and venting emissions from 2030 to 2050 in a baseline scenario.
- Aggregate future installation level emissions attributed to routine flaring/venting and subtract this from the total flaring/venting emissions profile.
- Given that progress is likely to be made on achieving ZRFV gradually from 2025 to 2030, build an arbitrary tapering of emissions abatement from 2025 to the peak of the annual abatement in 2030. This was done by assigning 20% of that peak to 2026, then 40% in 2027, 60% in 2028 and 80% in 2029.

H. GHG intensity and carbon intensity

This report uses two different intensity measures:

GHG intensity measures the overall amount of GHGs (carbon dioxide, methane and nitrous oxide) emitted to produce each barrel of oil equivalent.

UKCS average: total UK GHG emissions ((including terminals) using EEMS or NAEI data) divided by total UK sales production (using NSTA data).

Facility average: facility GHG emissions ((excluding terminals) using EEMS data) divided by all sales production exported by that facility (using PPRS data).

Carbon intensity measures specifically the amount of carbon dioxide emitted to produce each barrel of oil equivalent.

UKCS average: total UK CO_2 emissions ((from combustion and including terminals) using ETS data) divided by total UKCS sales production (using NSTA data).

Facility average: facility CO_2 emissions ((from combustion and excluding terminals) using ETS data) divided by all sales production exported by that facility (using PPRS data).

Notes:

While GHG intensity is a more complete calculation, it relies on detailed non-CO_2 GHG data which can vary in quality. Therefore, carbon intensity is frequently used, particularly in an international context where data for non-CO_2 GHGs can be difficult to obtain. For completeness, both GHG intensity and carbon intensity are covered where possible in this report.

EU/UK ETS carbon dioxide datasets omit carbon dioxide emissions produced via non-combustion (i.e. vented carbon dioxide) therefore carbon intensity calculations performed using ETS data lack CO_2 from these sources.

North Sea Transition Authority

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