North Sea Transition Authority

Emissions Monitoring Report

2024

Contents

The document can be found on the NSTA's website.

This document is available in large print, audio and braille on request. Please email: correspondence@nstauthority.co.uk with the version you require.

Enquiries to:
North Sea Transition Authority
Sanctuary Buildings, 20 Great Smith Street
London
SW1P 3BT

Email: correspondence@nstauthority.co.uk

Published by the North Sea Transition Authority

Executive summary

The UK's oil and gas industry, with its skills and infrastructure, can play a crucial role in accelerating the energy transition to net zero and support energy security as we transition. The UK continues to need oil and gas and, even as demand declines, is likely to remain a net importer to 2050. The carbon intensity of producing gas in the United Kingdom Continental Shelf (**UKCS**) is on average almost four times lower than importing gas in Liquefied Natural Gas (**LNG**) form, which involves production, transport and liquefaction. This helps support a case for continuing domestic production while we use gas. The sector supports tens of thousands of direct and indirect jobs and has the expertise needed to deliver the essential carbon and hydrogen storage potential required to meet the UK's net zero targets.

However, the upstream industry's overall production emissions still account for just over 3% of overall UK emissions, and gas imported from Norway via pipeline is cleaner than UK production, despite similarities between the two basins, demonstrating the potential for improvement. For domestic production to continue, it must become cleaner. North Sea industry has committed to reaching net zero by 2050, and a 90% reduction by 2040, while also agreeing interim targets with government, including a halving by 2030. It is vital that operators deliver on these pledges to preserve widespread support for the sector.

The North Sea Transition Authority (NSTA), as independent regulator, continues to hold the sector to account on its emissions targets, while also prioritising measures to accelerate the transition and secure energy production. Since 2021, the NSTA has published annual Emissions Monitoring Reports which present a wide range of data on overall greenhouse gas (GHG) emissions, methane emissions, performance benchmarking and flaring and venting to track industry's progress. Encouragingly, emissions have been on a downward trajectory in recent years, due to a combination of 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 key findings in the latest report show that reductions in overall emissions continued in 2023, though there were increases in some areas:

- **In 2023, UKCS upstream GHG emissions fell by an estimated 4%, contributing to a reduction of 28% between 2018 and 2023.**
- **50% of the reductions achieved between 2018 and 2023 were through active emission reduction measures, with the rest linked to assets going offline or approaching Cessation of Production (CoP).**
- **Combustion of hydrocarbons for offshore power generation made up 79% of emissions in 2023, followed by flaring, 17%, venting, 3%, with other non-combustion processes making up the rest.**
- **As expected in a basin with declining production, while total emissions fell, average emissions intensity for offshore assets is projected to have increased to 24 kgCO_2e/boe in 2023 from 22 kgCO_2e/boe the previous year, i.e., as the rate of production declines outpaced emissions reductions. This is a trend we expect to continue even as emission reductions continue. Globally, using an internationally comparable data set, and due in particular to the UK's strong performance on methane, UK upstream offshore emission intensity is more than 30% lower than the global average. The UK must continue to compare favourably with other nations to retain its social licence to operate.**
- **Operators reduced flaring by 2.4% last year, contributing to a drop of 49% between 2018 and 2023.**
- **In the NSTA Business as Usual scenario (BAU) – which carries forward implemented measures, but assumes no further abatement to create a baseline – achieving the 2030 target of 50% appears within reach, which is a great testament to the work already done, but just one step on the way and does not diminish the urgency of further abatement.**

While the NSTA recognises that operators have done impressive work, the 2030 target is the absolute minimum and further action is required to ensure that industry gets on long-term emission reduction pathways, and also meets and surpasses its targets. Rapid and sustained emissions reduction continues to be critical, as operators will need to deliver reductions long after 2030. They are already making decisions that will impact their ability to meet commitments up to and beyond the end of this decade and play their part in supporting the government on net zero.

The NSTA published the OGA Plan, following extensive consultation, in March 2024 to provide certainty and help operators make clear, long-term plans, putting them on the pathway to net zero. It supports the delivery of our revised Strategy, which introduced a range of net zero obligations on the industry, and sets out emissions reduction principles and requirements in four areas:

- **Investment and efficiency:**
  Operators must make investments to cut their operational emissions. This includes investment in specific technology to improve the efficiency of existing power generation; process operations to reduce emissions of existing assets; as well as planning for the deployment of emissions reduction technology and measurement in new and planned projects.
- **Platform electrification and low carbon power:**
  As power generation contributes the bulk of production emissions, electrification or low-carbon power must play a significant role in reducing that volume including in future developments. For existing developments, where the NSTA considers electrification reasonable, but it has not been done, there should be no expectation that the NSTA will approve Field Development Plans and similar decisions that give access to future hydrocarbon resources on that asset.
- **Inventory:**
  There will be increased scrutiny of assets with high emissions intensity and their CoP dates. Closing some low-producing, high-polluting installations earlier could allow higher producing and cleaner new assets to come online while still reducing emissions. CoP dates will also be set earlier to allow for better planning.
- **Flaring and venting:** Operators should reduce flaring and venting to the lowest possible levels, continuing the NSTA's ongoing work in this area. All new developments should be developed with zero routine flaring and venting, with no routine flaring and venting for all of 2030. In the interests of transparency, the NSTA will publish a list of assets which flare routinely, from later this year.

Net zero and economic recovery go hand-in-hand. Delivering the Plan will support progress and taking serious action on emissions reductions will enable the domestic oil and gas industry to maintain its social licence to operate, ensuring the nation can benefit from a domestic resource as we transition.

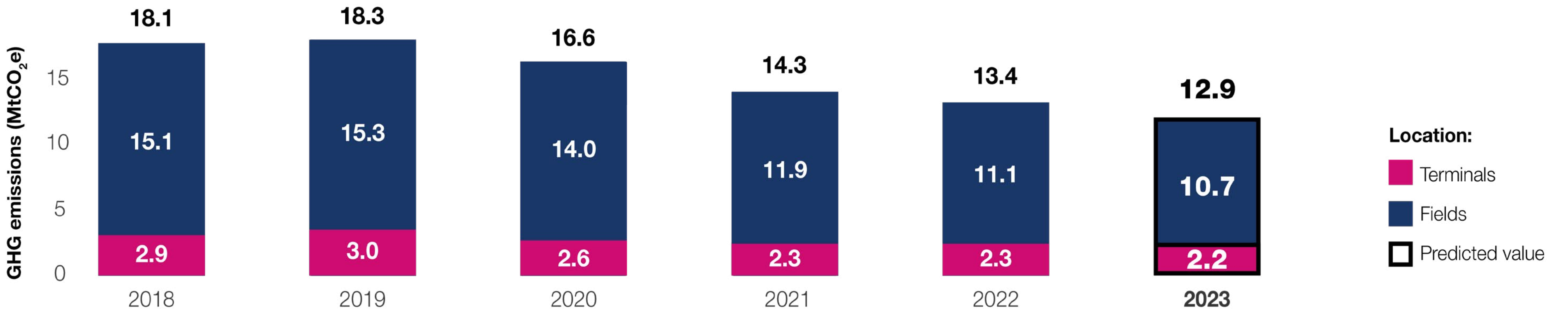
1. UK upstream oil and gas emissions

1.1 2023 Emissions trends

Upstream oil and gas GHG emissions declined in 2023 for the fourth year in a row, falling by an estimated 4%. This is in addition to a larger than expected fall in 2022 of 6% confirmed by revised and updated official data released by the National Atmospherics and Emissions Inventory (**NAEI**) earlier this year, resulting in an overall estimated reduction relative to 2018 of 28%.

As reported in last year's Emissions Monitoring Report , 50% of the decrease in emissions came from actively producing assets, with the other 50% coming from those assets which had ceased production or are approaching CoP. Of those active assets, the majority of reductions were in power generation, followed by flaring and venting.

Figure 1: Progress of the UK upstream oil and gas industry (source: NAEI, EEMS, ETS, NSTA)



Of the 12.9 $MtCO_2e$ of GHGs emitted from the upstream oil and gas industry in 2023, 83% is estimated to come from offshore facilities which extract and initially process oil and gas. Terminal emissions comprise 17% of the industry total. Terminals, which process and transport hydrocarbons from offshore fields, add additional sources of emissions such as fugitive emissions from equipment leaks and emissions from terminal operations. These facilities contribute to the overall emissions through activities like gas processing, storage, and transportation, further highlighting the importance of comprehensive emissions management across both offshore fields and associated terminals.

Measuring emissions

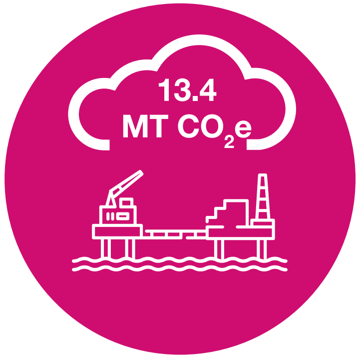
*Full UKCS emissions data is analysed using data from the NAEI. This dataset covers up to 2022 and includes both onshore and offshore fields and terminals, giving a full picture of upstream emissions. While NAEI data for 2023 will not be published until 2025, it is possible to estimate the industry's 2023 emissions with a good degree of confidence using the Environmental Emissions Monitoring System (**EEMS**) collected by Offshore Petroleum Regulator for Environment and Decommissioning (**OPRED**) and the UK Emissions Trading Scheme (**ETS**) datasets although these are not as comprehensive as the NAEI. In last year's report the NSTA estimated that emissions had reduced by 3% in 2022.*

1.2 Upstream GHG emissions in context

GHG emissions from upstream oil and gas activity accounted for just over 3% of net UK territorial GHG emissions in 2022 according to data from the NAEI.

This is unchanged from 2021. The 13.4MT CO_2e produced by the upstream oil and gas industry in 2022 is just under the total emissions of the North East of England (UK local authority and regional greenhouse gas emissions national statistics, DESNZ, 2024). A comparison with emissions from other sectors in the UK is shown in Figure 2:

Figure 2: Comparison of oil and gas emissions to a region in the UK
(source: NAEI)



Emissions from upstream oil and gas operations in 2022 are **just over 3 times the total emissions of Birmingham**

1.3 Composition of upstream emissions

CO_2 emissions consistently drive the overall trend in GHG emissions from upstream oil and gas production in the UK, due to CO_2 accounting for 89% of total emissions.

Significant reductions in CO_2, N_2O and CH_4 emissions have been achieved since 2018, as shown in Table 1.

Table 1: UK upstream oil and gas GHG emissions reductions to 2022 (source: NAEI)

Gas type	Emissions reduction 2018–2023*	Emissions reduction 2022–2023**
CO_2	26%	4%
CH_4	52%	4%
N_2O	26%	4%
Total GHGs	**28%**	**4%**

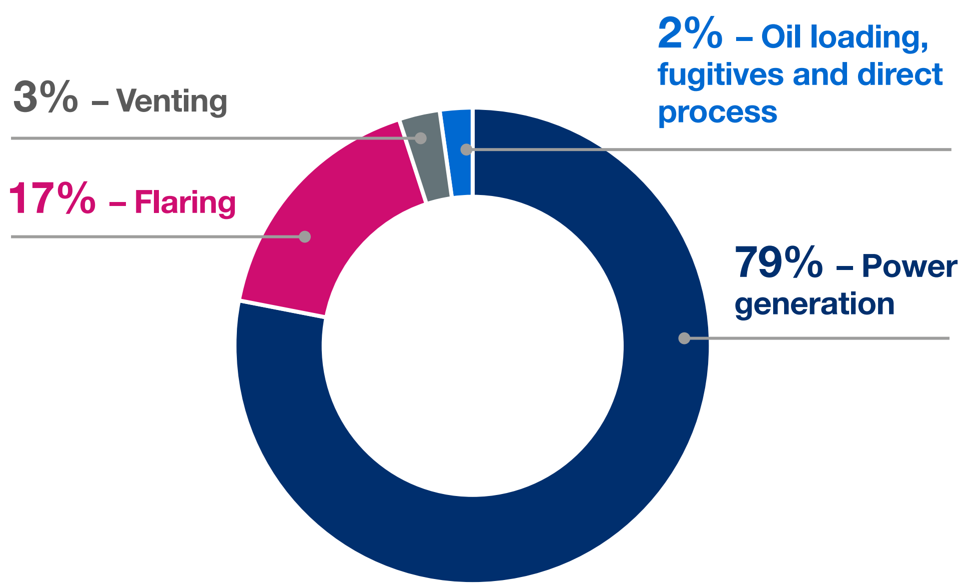
* – 2018–2022 calculation uses NAEI data which includes terminals and fields

* – 2022–2023 calculation uses NSTA projection data

1.4 Sources of emissions

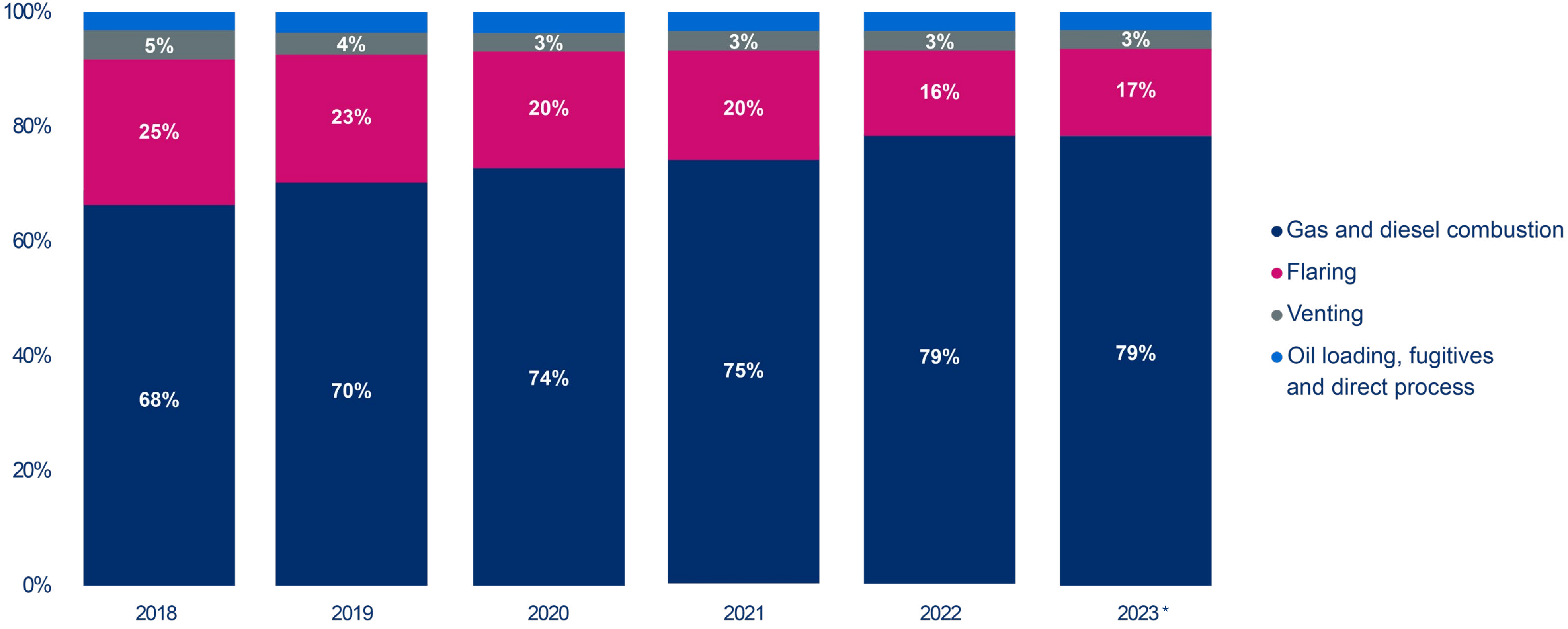
EEMS data for 2023 shows that emissions from offshore fields (excluding terminals) were primarily driven by several key sources. The largest contributors were gas and diesel combustion for power generation, followed by flaring and venting. Figure 3 gives a full breakdown of 2023 offshore GHG emissions by source:

Figure 3: 2023 offshore field emissions by source (EEMS 2023)



The proportion of Power Generation emissions grew from 68.1% in 2018 to 78.7% in 2023 as emissions from other sources – particularly flaring – have fallen at a greater rate. A summary of how the shares of these emissions have changed by source since 2018 is presented in Figure 4:

Figure 4: Offshore fields GHG emissions per source 2018–2023 (source: NAEI Field Data, EEMS)

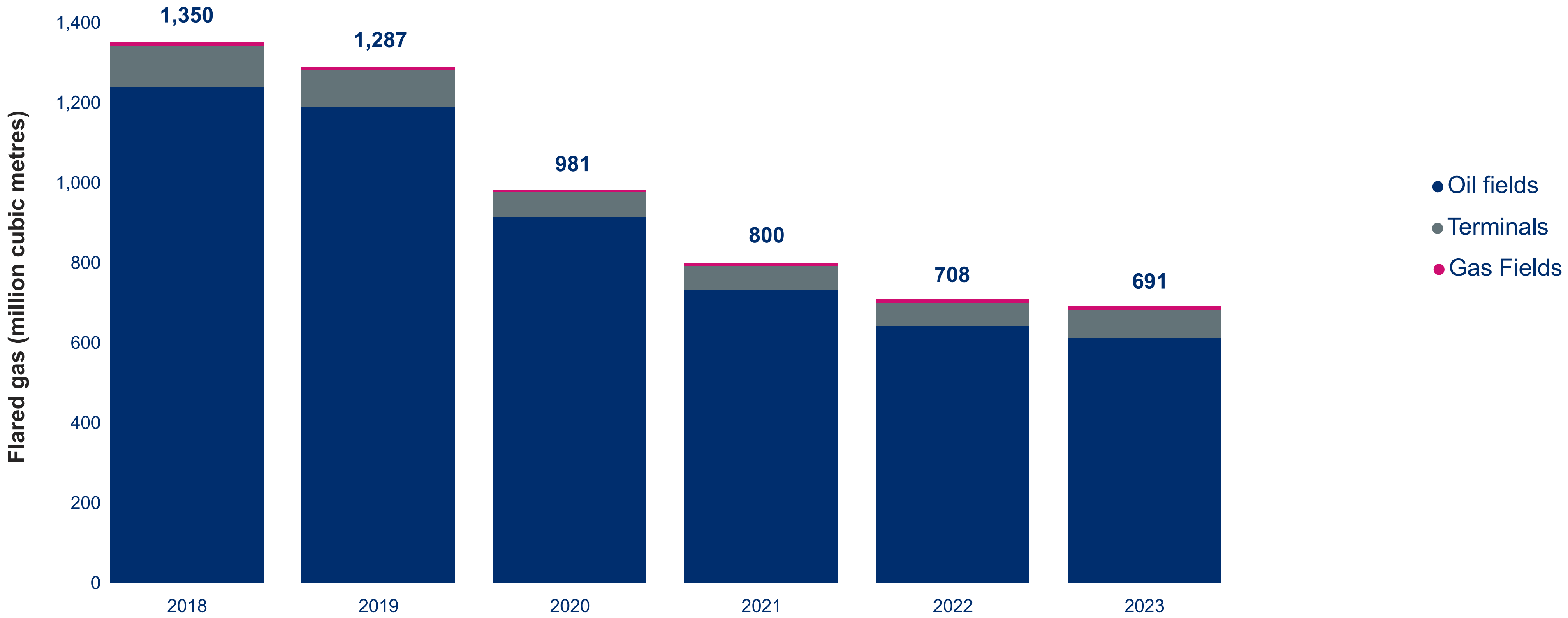


* – 2023 calculation uses EEMS data

1.5 Flaring and venting activity

The below Figure 5 shows the volume of gas flared from 2018–2023:

Figure 5: UK upstream oil and gas flaring, 2018–2023 (source: Digest of United Kingdom Energy Statistics (DUKES) E.1)



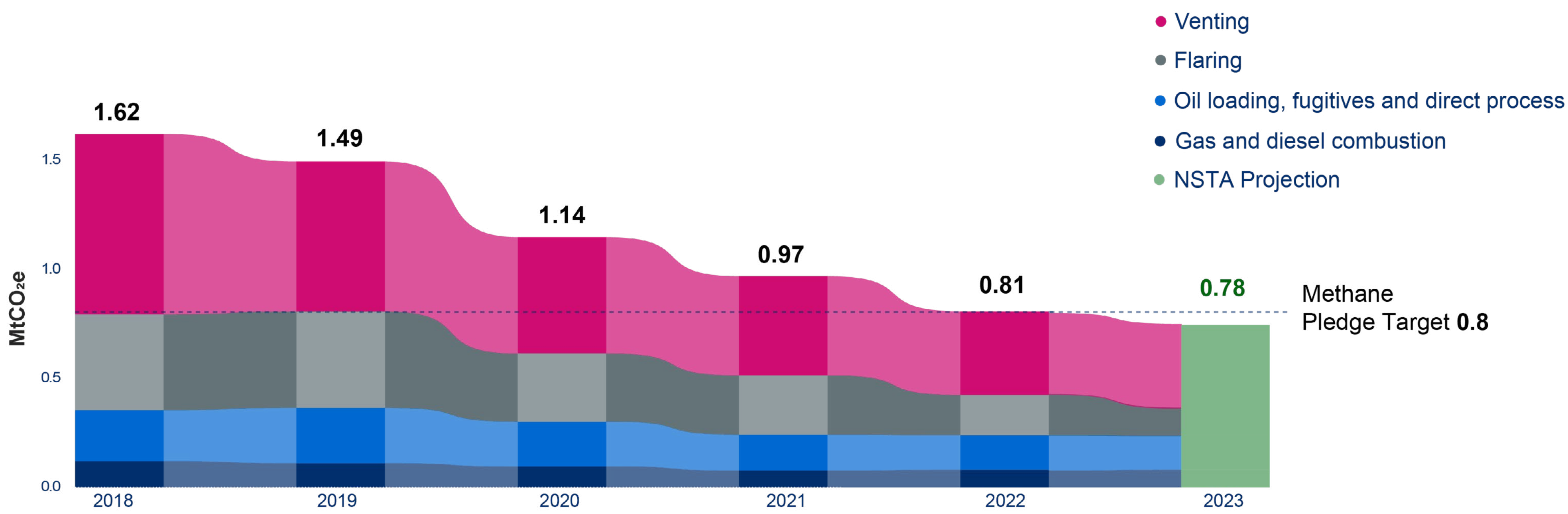
In 2023, the total volume of gas flared was 691 million cubic metres (mcm). This is the lowest level of flaring recorded in DUKES, and also represents a decrease of two thirds since its peak in 2001. This flaring was predominantly from oil fields, which contributed 88% of the total volume. Terminals accounted for 10%, while gas fields contributed the remaining 2%. This represents a 2.4% decrease from the previous year. In total, there has been a significant 49% reduction in gas flaring since 2018.

1.6 Methane emissions

In 2023, the total oil and gas industry (fields and terminals) methane (CH_4) emissions are expected to be 27,857 tonnes – or 0.78 $MtCO_2e$. This represents 1.7% of total UK methane emissions.

The United Kingdom is a participant in the Global Methane Pledge – a commitment to reduce methane emissions by at least 30% from 2020 levels by 2030. The UK upstream oil and gas industry has reduced its methane emissions by 29% between 2020 and 2022, and is expected to meet this target in 2023 with a further decrease forecast. The figure below illustrates the oil and gas industry's progress towards this target. Despite this, there is still much work to be done to assist the wider economy in meeting this target.

Figure 6: Methane emissions by source, 2018–2023 (source: NAEI)

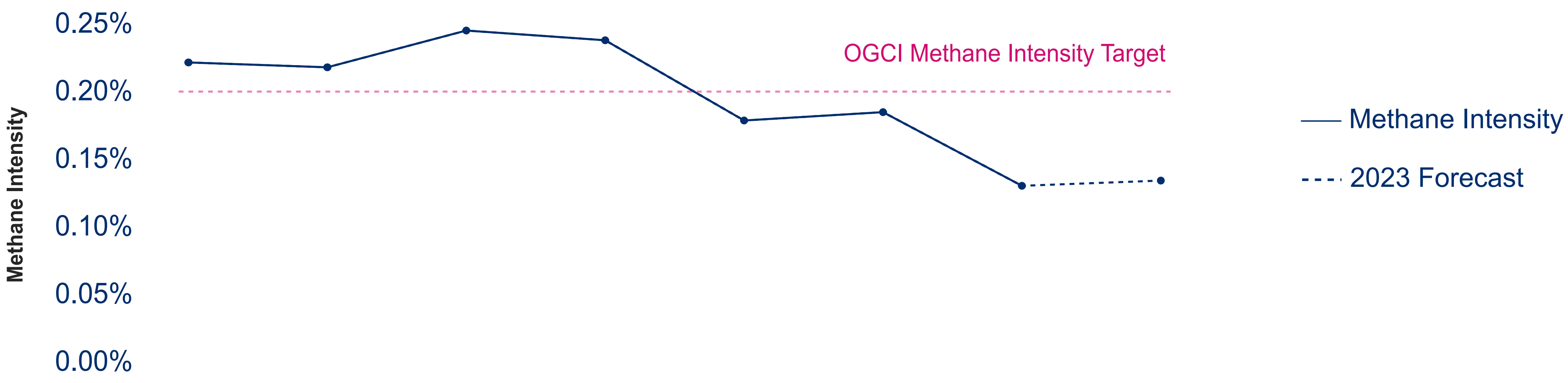


Flaring and venting were responsible for 71% of methane emissions in 2022. A further decrease in venting emissions is expected in 2023, helping to meet the target as predicted in 2023.

As part of the North Sea Transition Deal (**NSTD**), industry also subscribed to the OGCI 2025 methane intensity commitment which stipulates a methane intensity target of "well below" 0.20% by 2025.

After an increase from 2020 to 2021, methane intensity declined by 0.5% from 2021 to 2022. The NSTA expects methane intensity to continue to be well below the Oil and Gas Climate Initiative (**OGCI**) Methane Intensity target in 2023 as can be seen in Figure 7.

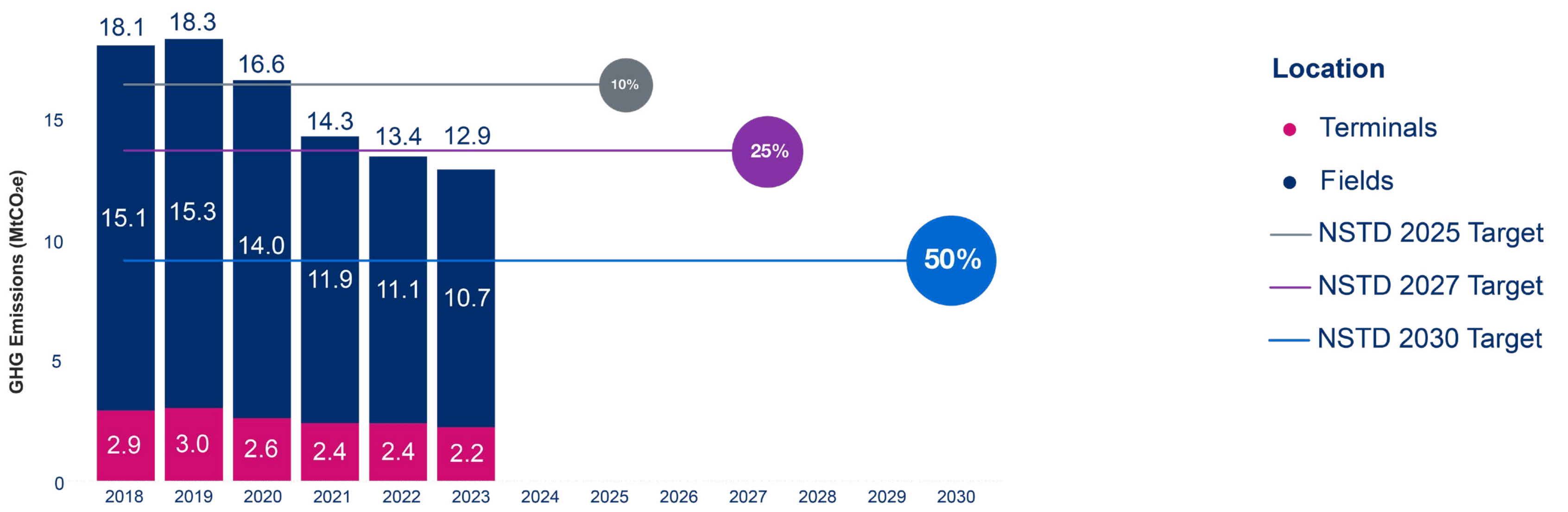
Figure 7: Upstream oil and gas methane intensity per year, 2016 to 2023 (source: NAEI, EEMS, ETS, NSTA)



2. Progress towards NSTD emissions reduction targets

The NSTD is a sector deal between the UK government and the oil and gas industry launched in 2018, which aims to significantly reduce emissions across the sector. The plan sets out three emissions reduction targets for industry to meet: 10% reduction by 2025, 25% reduction by 2027 and 50% reduction by 2030. The reduction is measured from the 2018 baseline of emissions. The UK's progress against these targets is set out in Figure 8 below:

Figure 8: Progress of the UK upstream oil and gas industry against the NSTD targets (source: NAEI, EEMS, ETS, NSTA)



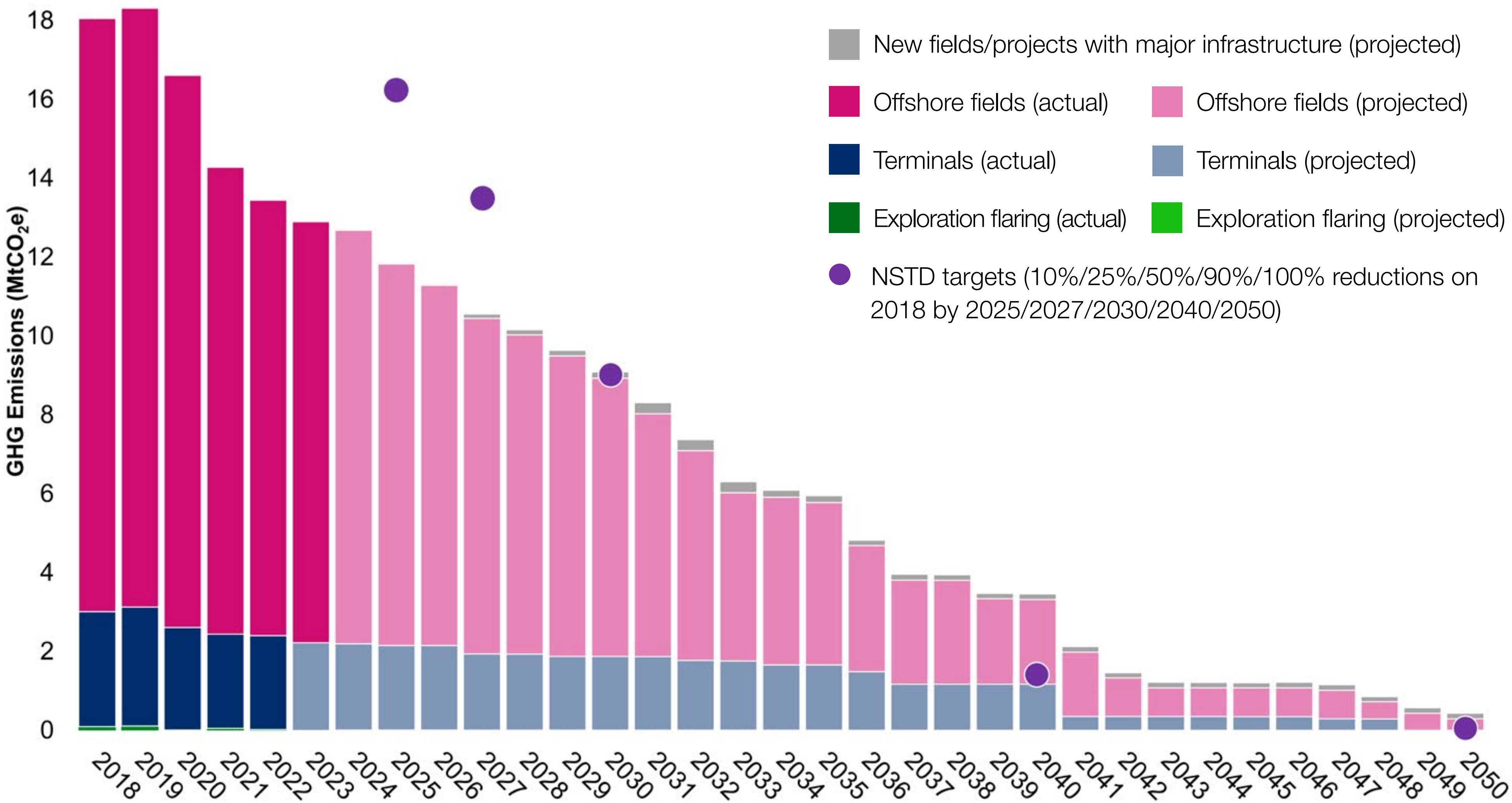
3. BAU projection of UK upstream oil and gas emissions: 2024 update

The BAU projection serves as a ‘no-further-abatement’ baseline from which to measure the effectiveness of applying abatement scenarios relative to UKCS progress in achieving the NSTD targets. It is not a best forecast of the expected trajectory, as the NSTA expects and require a range of abatement to continue to be implemented, but an effective baseline to compare against.

The BAU projection adopts the following criteria:

- Production from existing facilities continues without additional abatement efforts, but with already implemented measures carried forward.
- Abatement gained from zero routine flaring and venting (ZRFV) is excluded.
- The design of new fields/projects with major infrastructure are compliant with NSTA guidance and the OGA Plan.

Figure 9: Progress of the UK upstream oil and gas industry against the NSTD targets
(source: NAEI, EEMS, ETS, NSTA. New fields/projects with major infrastructure (projected) as of 30/08/2024).



3. BAU projection of UK upstream oil and gas emissions: 2024 update

Following a reduction of 4% between 2022 and 2023, NSTA's BAU projection indicates a GHG emissions decrease of 2% in 2024, followed by a more substantial 7% drop in 2025. Beyond 2025, the decline is projected to continue steadily, averaging a rate of around 12% annually. Without abatement, the principal factor for reduced GHG emissions in the BAU scenario is the CoP of UKCS facilities; according to the latest UKSS, around 30 assets are expected to cease production before the end of 2025.

Achieving the 2030 NSTD target of 50% appears within reach on the current BAU trajectory is testament to the work already done; however, the uncertainty of the projection remains high and therefore achievement of the 2030 target without further abatement is not guaranteed. Crucially it is the absolute minimum expectation of industry that NSTD targets shall be surpassed – complemented by an assured and sustained effort in realising effective decarbonisation beyond 2030. Electrification of offshore facilities and deployment of flare and vent reduction technologies are key drivers to the UK Stewardship Survey (**UKSS**) in reducing GHG emissions and maintaining net zero commitment. Hence, the industry's commitment to advancing emission reduction initiatives is crucial for navigating the immediate and longer term landscape.

4. Abatement opportunities

4.1 Offshore electrification

In 2023, it was estimated that 79% of UKCS GHG emissions originated from the combustion of natural gas or diesel. For several years, the NSTA and industry have explored alternatives to these fossil fuels, focusing on electricity as a cleaner energy source for those offshore facilities with longevity in the UKCS. This electricity may be supplied by the UK's national grid or from offshore renewable energy; both options offering a reduction in emissions per unit of energy delivered, compared to traditional offshore power generation methods. With a deeper understanding of the complexities and benefits of electrifying offshore facilities, electrification is now recognised as a principal component in attaining the most significant decrease in emissions across the UKCS.

The NSTA demonstrates the potential extent of GHG emissions abatement savings from electrification of offshore facilities by applying scenarios measuring the cumulative abatement across low, mid and high case electrification deployment. Where the Annex provides description of the methodology and assumptions applied, the following summarises the scenario criteria:

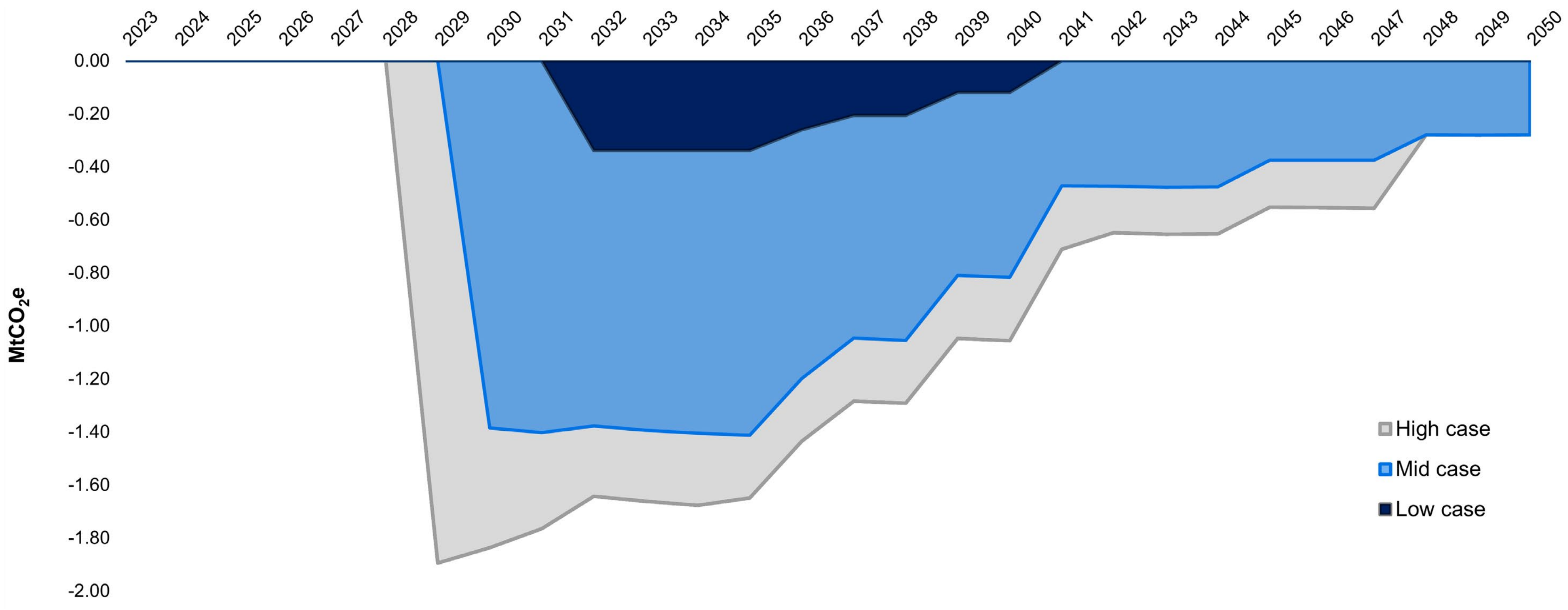
Table 2: Summary of the scenario criteria

Electrification deployment scenario	Assumption
Low case	**Seven assets** are **partially electrified** in 2032 and does not include projected new fields/projects with major infrastructure.
Mid case	**Eight assets** are **fully electrified** in 2030 and includes projected new fields/projects with major infrastructure.
High case	**Nine assets** are **fully electrified**, and **eight assets** are **partially electrified** in 2029 projected new fields/ projects with major infrastructure.

Figure 10 illustrates the abatement profiles for low, central, and high technical deployment scenarios. From 2030 to 2050, the total cumulative abatement in the mid-case scenario is estimated at approximately 17 $MtCO_2e$, representing an increase of almost 14% in abatement savings compared to 2023. This rise is attributed to facilities that have accelerated their plans to achieve first power by 2030, which were previously aimed at the later 'low case' date of 2032. The mid case scenario also assumes a slightly amended group of assets than was the case in 2022. Recognition by industry that total abatement savings diminish the longer abatement reduction projects take to commission, may be the driving force in increasing the appetite to achieve first power sooner.

The ambitious high-case scenario assumes that all necessary regulatory and economic conditions are met, enabling first power to be achieved by 2029. For 2024, the high-case scenario abatement is 3% lower than projected last year, possibly due to the extension of the first power date from 2028 to 2029 in this year's modelling. Theoretically, this change suggests that operators may favour shifting from high-case to mid-case electrification to achieve the target more economically and resource-efficiently than high-case electrification demands.

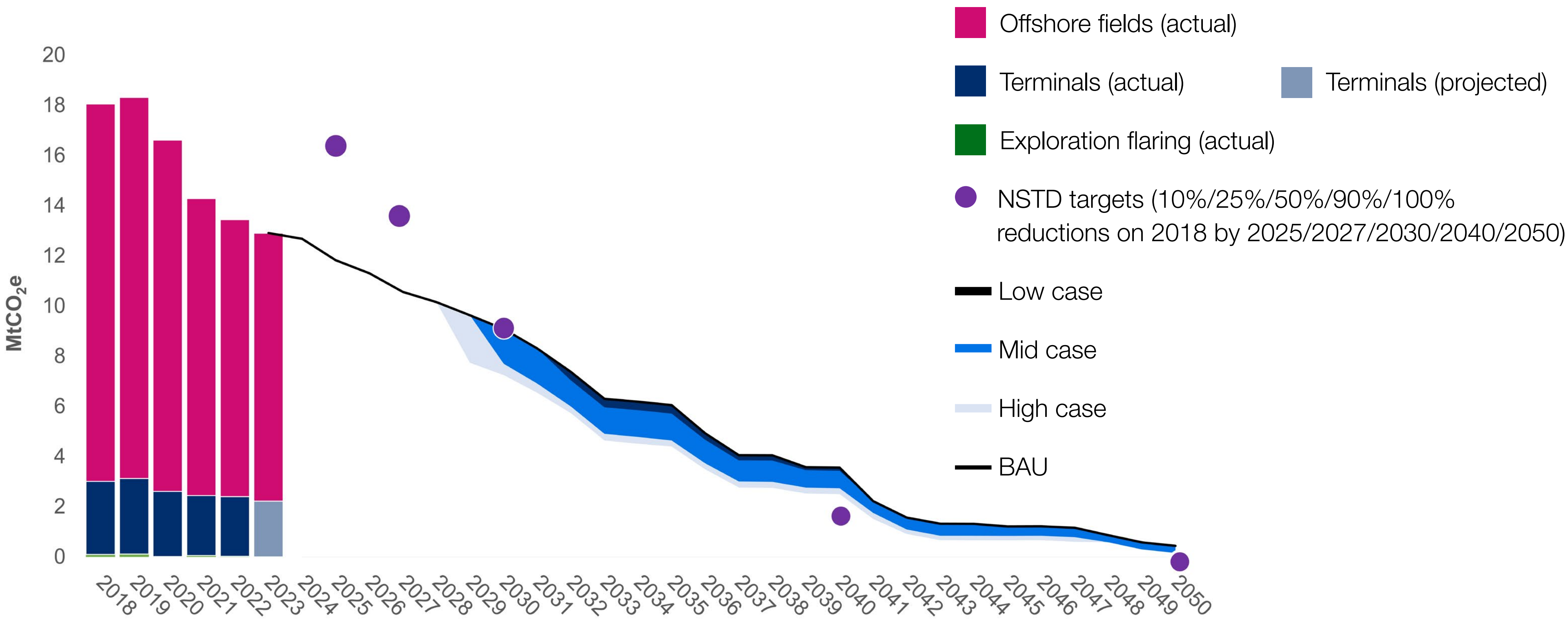
Figure 10: Projected GHG emissions and electrification abatement scenarios (source: EEMS, UKSS, NSTA)



It should be noted that the projections involve a degree of uncertainty surrounding their technical evaluation in relation to emissions reduction. Economic or regulatory changes could potentially impact these evaluations. The uncertainty regarding emissions reduction after 2040 is especially pronounced.

The effect of emissions abatement from electrification on achieving targets is demonstrated by comparing the BAU emissions projection with the technical electrification scenarios, as shown in Figure 11.

Figure 11: Projected GHG emissions for BAU and electrification abatement scenarios (source: NAEI, EEMS, UKETS, UKSS, NSTA)



The timeline for achieving first power across the scenarios impacts the effectiveness of electrification in reducing offshore GHG emissions. In this year's report, the range has been narrowed to four years – 2029–2032; as opposed to last year's 2028–2032 range.

Adopting the high-case scenario, with first power generation in 2029, offers substantial savings consistent with previous estimates, enabling an additional recovery of almost 4 $MtCO_2e$ between 2029 and 2030. Compared to 2018, this results in a 60% reduction in the industry's total GHG emissions by 2030, aligning with the projected 60% reduction for 2023.

Opting for the mid case scenario, with first power generation in 2030, results in slightly higher savings compared to the earlier estimates. Last year, abatement savings were projected at 15 $MtCO_2e$, while this year, 17 $MtCO_2e$ is deemed a more realistic value.

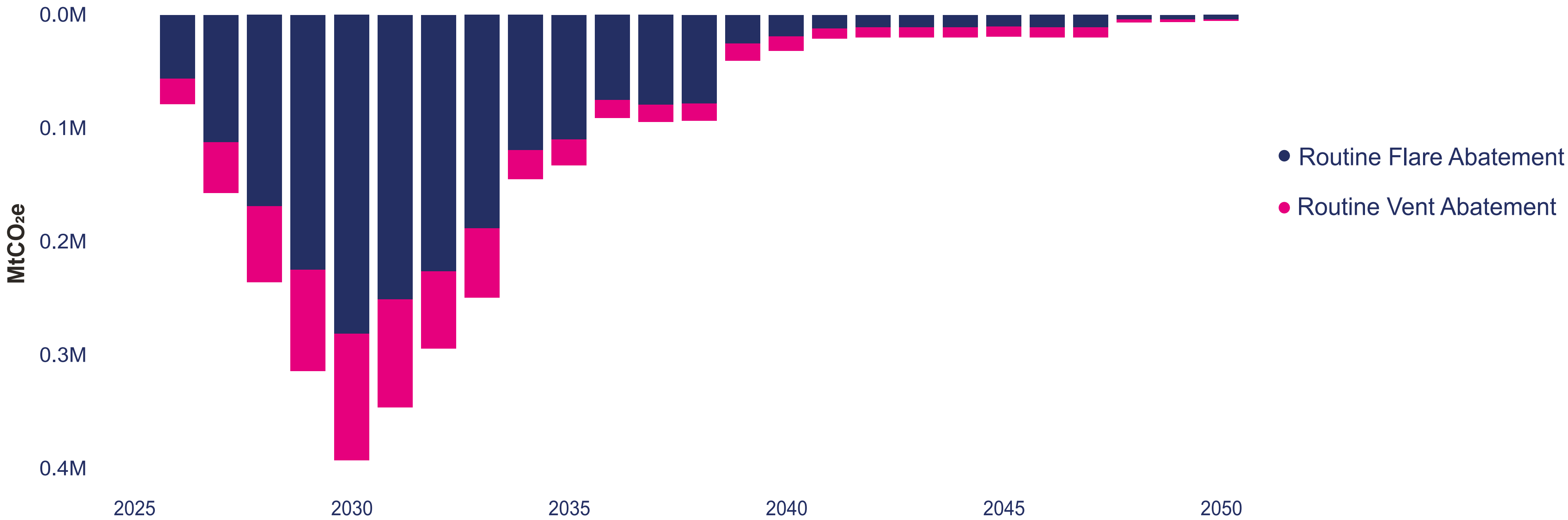
Beyond emissions reduction at production sites, electrification can enhance energy security by increasing net gas supply for the UK, which would otherwise be combusted offshore. In the mid case scenario between 2030 and 2050, electrification could eliminate an estimated 22% of offshore fuel gas demand, rising to over 28% in the high case.

It is important to note that the abatement potential in these technical scenarios is not a forecast but is based on the NSTA's best understanding of potential electrification projects. These scenarios involve assumptions to capture abatement from various deployment options and are subject to uncertainty.

4.2 Implementation of ZRFV

While positive progress has been made in reducing flaring activity from the UK upstream oil and gas industry (a 49% reduction was achieved between 2018 and 2023), flaring still accounts for 17% 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 critical that these activities are reduced or eliminated in the short term.

Figure 12: Annual estimated GHG emissions abatement relative to the baseline scenario from the implementation of zero routine flaring and venting from 2030 (source: NSTA)



The NSTA guidance mandates ZRFV for all by 2030. Additionally, all new projects with major infrastructure must be planned, designed, and developed on the basis of ZRFV.

Category A routine flaring and venting accounts for about half of current practices, while non-routine flaring and venting (Categories B and C) account for the remainder. Eliminating routine flaring and venting by 2030 has the potential to offer a marked reduction in GHG emissions. Secondary to expectations on routine flaring and venting, the NSTA urges industry to consider the minimisation of non-routine flaring and venting emissions as much as possible.

Projections are based on estimates of future emissions from flaring and venting provided by operators through the UKSS, along with current data for routine flaring and venting, sourced from NSTA consents data from 2023. The projection has used a tapering approach to build up to the savings calculated to be realised in 2030 (see Annex G for the detailed methodology).

Figure 13 displays the estimated annual emissions reduction via ZRFV implementation. The initiative is expected to reduce emissions by nearly 3 $MtCO_2$ e between 2025 and 2050 with 74% coming from routine flaring elimination and 26% from routine venting elimination.

2030 sees the peak annual level of abatement from ZRFV. Following this, declining baseline flaring and venting rates and facility cessation of production leads to a decrease in year-on-year abatement.

4.3 Combined abatement

Figure 13: Projected GHG emissions for BAU, ZRFV and electrification abatement scenarios (source: NAEI, EEMS, UKETS, UKSS, NSTA)

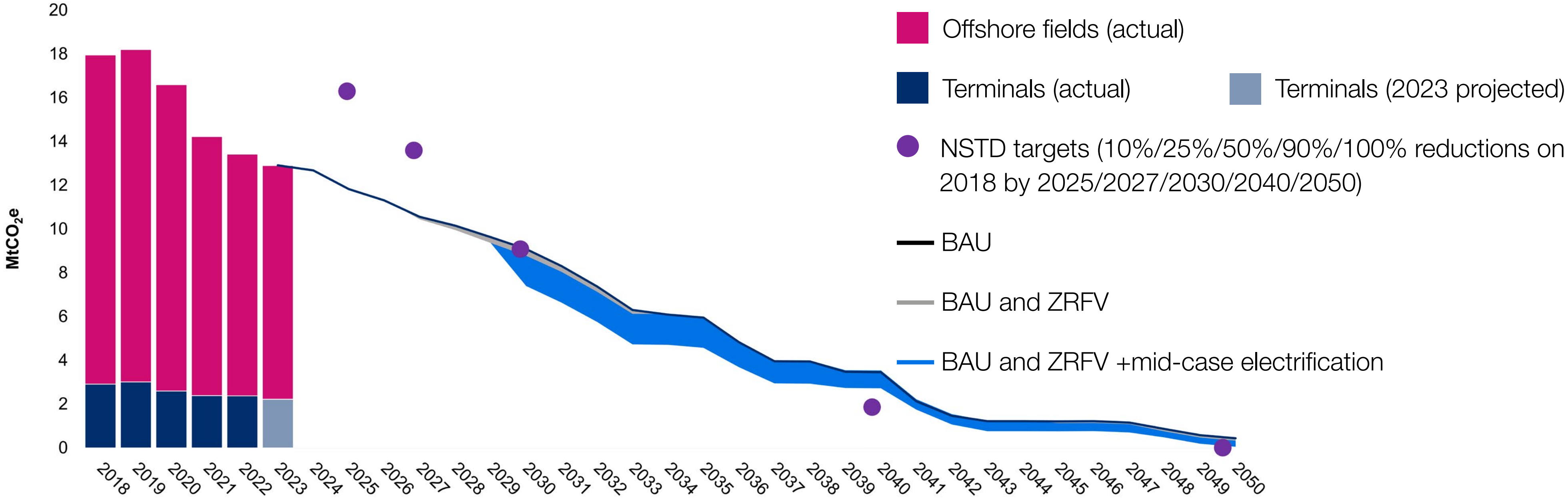


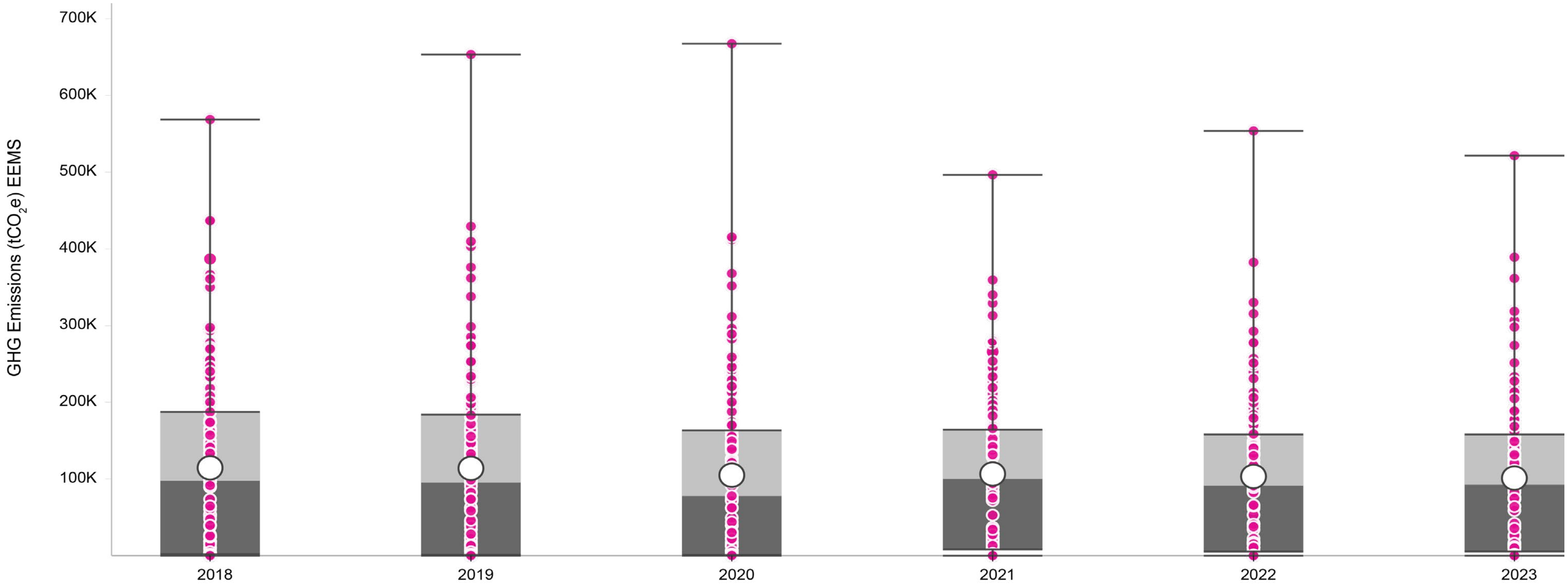
Figure 13 illustrates the potential combined reduction in GHG emissions from the electrification of offshore facilities and the elimination of routine flaring and venting. While ZRFV alone offers a modest 2.7% decrease in GHG emissions across the UKCS offshore industry, combining it with mid-case electrification by 2030 could result in additional savings in excess of 23% compared with the original 2018 baseline.

5. Emissions performance benchmarking

There is great variation in the size and type of facilities in operation on the UKCS with a corresponding variation in the emissions produced by each asset.

The distribution of emissions by region provides valuable insights into the emissions performance of facilities across the UKCS, as shown in Figure 14:

Figure 14: UKCS distribution of emissions, 2018–2023 (source: EEMS)



In 2023, the average facility emitted 101 kilotonnes of CO_2 equivalent (kt CO_2e), marking a slight decrease from the 103 kt CO_2e recorded in 2022. This overall reduction reflects ongoing efforts to enhance operational efficiencies and reduce emissions.

However, it is important to note that while large emitters have historically reduced their emissions year on year, 2023 saw a stabilisation in emissions from facilities in the 75th percentile, which remained at 158 kt CO_2e, the same as in 2022. This highlights the challenges faced by the largest emitters in achieving further reductions and underscores the need for targeted strategies to address emissions from these key facilities.

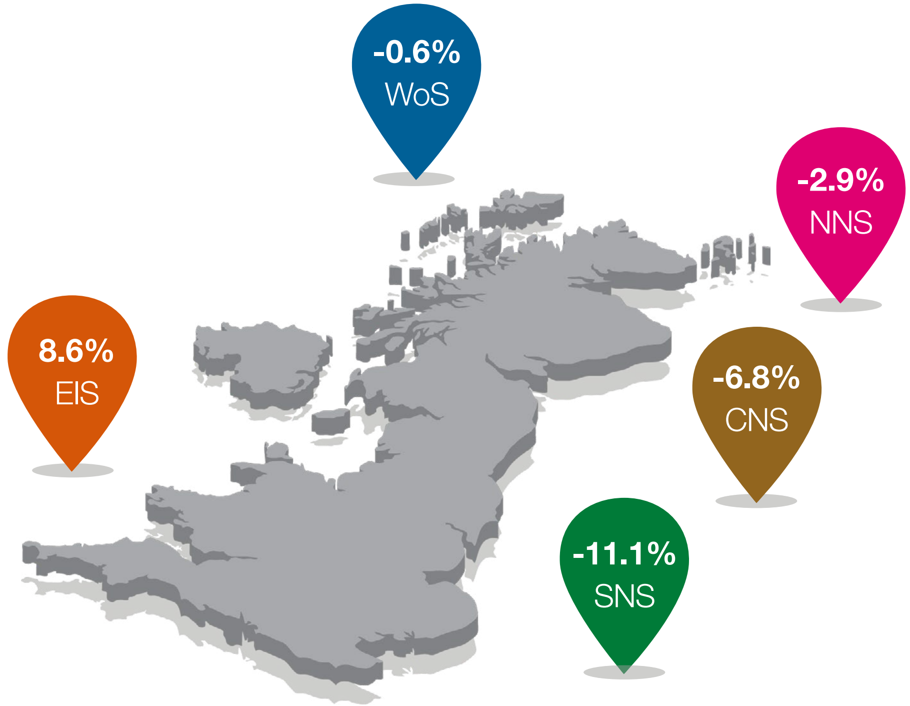
5.1 Regional performance on overall GHG reduction

Breaking down the UKCS emissions into different regions illustrates which areas are driving these changes. The regions of the UKCS are as follows:

- NNS – Northern North Sea
- CNS – Central North Sea
- SNS – Southern North Sea
- WoS – West of Shetland
- EIS – East Irish Sea

Figure 15 illustrates the varying trends across these regions, providing a clear picture of their individual contributions.

Figure 15: Regional breakdown of offshore fields' GHG emissions reductions in 2023 (source: EEMS)

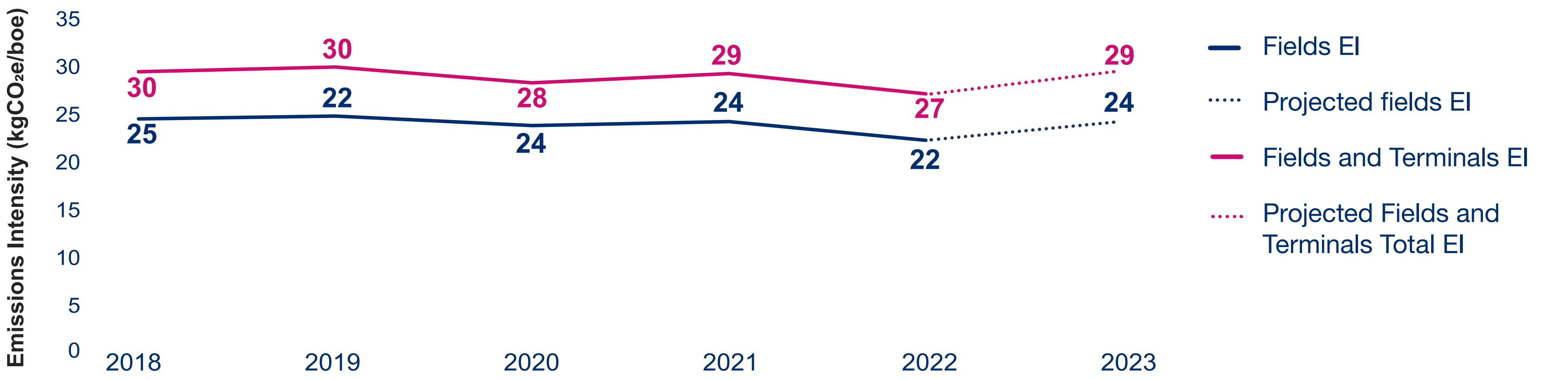


While there has been an overall decrease in UKCS emissions, year on year emissions change has varied considerably across different regions. There have been small decreases in the WoS and NNS – a contrast to last year's year-on-year change, where the shutdown of large emitters led to a larger decrease. There has been an increase in the EIS – there are just two remaining facilities in this group, both of which have increased their emissions primarily due to an increase in flaring and venting.

5.2 Emissions intensity

Emissions intensity measures the overall amount of GHGs (here including carbon dioxide, methane and nitrous oxide) emitted to produce each barrel of oil equivalent. The NSTA considers this both for offshore activity only as our main measure, consistent with international approaches, and for completeness with terminals consistent with the emissions reduction targets. This measure can be tracked to assess how the emissions intensity of UKCS activities change over time, as shown in the Figure 16 below:

Figure 16: Industry emissions intensity, 2018–2023 (source: NAEI, NSTA)



In line with a declining basin and falling production, NSTA projections suggest that 2023 saw an increase in emissions intensity for offshore assets to 24 kg CO_2e. This estimated rise is a consequence of production decline, even with continuing emissions reductions and abatement.

5.3 Emissions intensity of offshore assets

Measuring the emissions intensity of individual assets provides a way to compare performance in the UKCS which can be difficult when comparing absolute emissions alone.

In a change from the 2023 Emissions Monitoring Report, which focussed on carbon intensity only, the charts in this section show emissions intensity for offshore assets in the UKCS. This allows data from EEMS to be reported up to 2023, giving a more recent picture of analysis. For a more detailed examination of the analysis in this section, please see the NSTA Emissions Monitoring dashboard, where further insights into these trends are available.

Figure 17: 2023 emissions intensity breakdown by installation type and age (source: EEMS)

Installation age	Floating	Large platform	Small platform
0–10 years	20	12	6
11–25 years	36	20	18
> 25 years	34	52	33

The above chart shows that older, large assets have the highest GHG intensity on average and new, small assets have the lowest.

5.4 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.

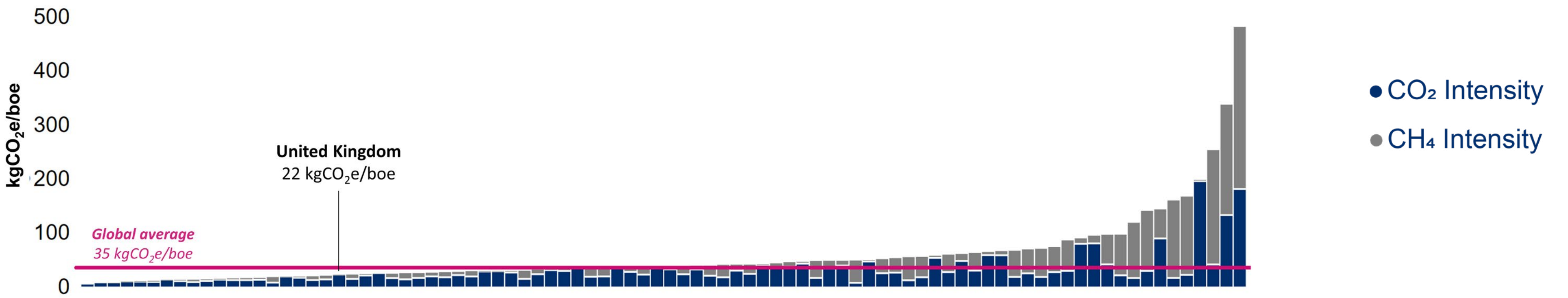
6. International benchmarking

Not all countries publish their emissions data by sector therefore in order to compare UK oil and gas emissions internationally, the NSTA has analysed data from Rystad Energy.

This year, for the first time, it is possible to compare the UK's upstream production emissions intensity to other countries by including Rystad's proprietary upstream methane emissions data* alongside upstream carbon emissions, providing a broader view of global upstream production greenhouse gas emissions (excluding terminals). It should be noted that Rystad's carbon and methane upstream emissions data are sourced from reported, measured and modelled emissions data and as a result, estimated emissions intensities are not directly comparable to the UK upstream emissions intensities stated in previous sections of this report.

According to Rystad's data, in 2023, the UK had an estimated emissions intensity (CO_2 and CH4 only) of 22 $kgCO_2e$/boe, placing the UK in the best-performing quartile and 13 $kgCO_2e$ below the global average of 35 $kgCO_2e$/boe. See Figure 18 below.

Figure 18: International benchmarking of UKCS emissions intensity ($kgCO_2e$/boe) (source: Rystad Energy)



*Source: Rystad Energy, 30/08/2024. Rystad Energy's EmissionsCube is a proprietary, field-by-field emissions inventory database combining asset-level reported data, quality aggregated reported data, methane satellite data, and flaring satellite data (VIIRS Nightfire, Colorado School of Mines). See Annex for more information.

This dataset indicates the UK's methane emissions intensity to be 1 kgCO_2e/boe, compared to a global methane intensity average of 16 kgCO_2e/boe. The UK's relatively good methane emissions intensity performance illustrated in the Rystad data comparison is supported by its progress in reducing absolute methane emissions by more than 50% since 2018.

While the UK's methane intensity performance is strong when compared internationally, its carbon intensity can be seen to increasing. When compared to the carbon intensity international benchmarking reported in the NSTA's 2023 Emissions Monitoring Report (produced using Rystad data from 2022), the UK's carbon intensity increased from 19 kgCO_2/boe in 2022 to 21 kgCO_2/boe in 2023, driven by the effect of a faster decline in production than carbon emissions.

Although the UK ranks amongst high performers with regards to methane emissions intensity, a continued focus is needed to maintain control over carbon emissions and GHGs overall. Sustained efforts to drive down emissions are essential, particularly in a naturally declining basin where reduced production can significantly impact emissions intensity performance.

7. Conclusions

The North Sea oil and gas industry cut GHG emissions from its production operations by 4% in 2023 – the fourth annual decrease in a row. Last year's reduction contributed to an overall drop of 28% since 2018, which shows the sector has been making progress in its transition to net zero.

Half of the reductions achieved in the last five years were due to active measures, including investments in flaring reduction and more fuel-efficient equipment. The NSTA ensured continuous improvement by sharing best practice and holding the sector to account through robust stewardship and regulation. We closely scrutinise flaring consent applications, apply our sanctions powers where appropriate and use high-quality data to benchmark operators' performance. The permanent shutdown of older, high-emitting assets also brought emissions down.

While industry's progress on overall emissions has been impressive, emissions intensity for offshore assets is expected to have risen to 24 $kgCO_2e$/boe in 2023 from 22 $kgCO_2e$/boe in 2022, due to the rate of production declining more rapidly than emissions. Relatively high emissions intensity is common in more mature basins, but the UK's upstream industry should not use this as an excuse for inaction. Operators must continue to bear down on their overall emissions and keep intensities in check. This will help preserve the sector's social licence to operate and safeguard the skills and expertise needed to deliver the transition.

The NSTA will use the Oil and Gas Authority Plan (**OGA Plan**), published in March 2024, to get the sector on long-term pathways to net zero and ensure it meets and surpasses key emissions reduction targets. It makes clear that for domestic production to continue, it must get progressively cleaner, and calls for concerted action, including on low-carbon power, and an end to routine venting and flaring by 2030.

As revealed at this year's annual performance review of the UKCS's top 20 operators, industry has been developing plans for more than a dozen major decarbonisation projects, mostly involving low-carbon power and flaring and venting reduction. However, only around a quarter of those projects have reached final investment decisions – and none of those are electrification schemes.

Operators should quickly press ahead with decarbonisation proposals, as delays in commissioning reduce the volume of emissions which can be abated. Sustained emissions cuts will have to continue well into the 2030s and beyond if industry is to reach net zero by 2050. Swift investment decisions are crucial to make sure industry lives up to its commitments in the decades ahead.

8. Annex: Emissions Monitoring Report 2024 methodology

This document provides additional technical details and sources to accompany the analysis in the NSTA's 2024 Emissions Monitoring Report.

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

Source	Fuel Group	Activity Name
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
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

1B2a6 – Exploration, production and transport of oils

Source	Fuel Group	Activity Name
Abandoned oil wells (offshore)	Other emissions	Number of wells per year
Abandoned oil wells (onshore)	Other emissions	Number of wells per year

1B2b1 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Upstream gas production – offshore well testing	Other emissions	Exploration drilling :amount of gas flared
Well exploration (unconventional gas) – all sources	Other emissions	Non-fuel combustion

1B2b2 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Onshore natural gas gathering	Other emissions	Natural gas production (million m3/yr)
Onshore natural gas production (conventional)	Other emissions	Natural gas production (million m3/yr)

1B2b3 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Gas terminal – direct process	Other emissions	Non-fuel combustion
Gas terminal – other fugitives	Other emissions	Non-fuel combustion
Upstream gas production – fugitive emissions	Other emissions	Non-fuel combustion
Upstream gas production – direct process emissions	Other emissions	Non-fuel combustion

1B2b4 – Exploration, production and transport of gas

Source	Fuel Group	Activity Name
Upstream gas production – gas 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

The NAEI includes emissions from the combined heat and power (**CHP**) facility located at Sullom Voe Terminal (**SVT**) in the total figures for the UK upstream oil and gas sector. The NSTA, however, does not recognise these facilities as part of the industry. The NSTA has now identified the SVT CHP emissions from published sources and has deducted them from the NAEI totals from 2008 onwards.

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). GWP factors applied in the EMR 2024 are without inclusion of climate-carbon feedbacks (**no cc fb**) and over a 100-year timescale.

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

BAU emissions projections methodology

The NSTA updates its bottom-up BAU projection of the sector's GHG emissions based on recent historical emissions data for offshore installations using EEMS. The BAU projection assumes no further abatement. Expected CoP dates for each installation are based on operator submissions to the NSTA's 2023 UKSS.

Allowance is made for projected new fields and projects with major infrastructure. Inclusion of new fields and projects of major infrastructure in this list is without prejudice to Department for Energy, Security and Net Zero (**DESNZ**) or the NSTA granting consent to development.

For existing offshore installations which are expected to be in use after 2023 the NSTA is guided by EEMS data for previous years.

Onshore terminals data and projections are inclusive of Wytch Farm and Humbly Grove for which NSTA has used verified CO_2 emissions for 2021–2023 from UK ETS.

Emissions from exploration flaring are assumed to decline at 5% a year starting from 2022 levels as reported in the NAEI.

Current projections reflect best estimates of future emissions on an assumed baseline i.e. excluding platform electrification and elimination of ZRFV.

Projected emissions for a small number of recent and new installations and projects are based on operators' emissions forecasts as reported in the UKSS 2023 or in published environmental statements.

It is important to note that baseline emissions projections are not a forecast of upstream oil and gas GHG emissions and should not be used as such. Projections are based on an analytical approach that sets out to project historic data into the future. Therefore, emissions projections are subject to uncertainty and are underpinned by assumptions based on CoP dates and other relevant variables as mentioned previously.

Technical deployment scenarios for electrification abatement of oil and gas installations

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

- 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.
- Emissions histories for those assessed installations and expected cessation CoP based on 2023 UKSS responses.

- Assuming:
  - 100% abatement of power generation emissions for a fully electrified installation
  - 35% abatement of power generation emissions for a partially electrified installation
- Variables considered between each of the modelled cases are:
  - installations in scope
  - whether facilities are fully or partially electrified
  - first power year
- Scope 2 emissions (i.e. those emitted during the generation of imported electricity) are factored into the abatement modelling, assuming:
  - partially electrified facilities source electricity from offshore wind which has zero scope 2 emissions
  - fully electrified facilities source all electricity from the UK electricity grid
  - 'best estimate' of future power demand is combined with DESNZ published forecast UK electricity grid emission factors to calculate scope 2 emissions which are subtracted from the scope 1 abatement to provide scope 1 abatement net of scope 2 emissions

Methodology updates to the technical deployment scenarios this year include:

- Assumes first power for the high case in 2029, mid and low cases in 2030 and 2032, respectively. For the Emissions Monitoring Report 2023, the high case assumed first power in 2028.
- To the knowledge of NSTA, facilities assessed in the 2024 Report reflect the most current data regarding electrification projects.

As with the BAU projection analysis, the abatement potential estimated in the electrification scenarios is not a forecast and should not be used as such. 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 deployments and are, therefore, subject to uncertainty.

Routine flaring and venting emissions abatement methodology

The NSTA offers projections demonstrating the impact of cessation of ZRFV by 2030 and adopting the following methodology to estimate abatement via ZRFV by 2030, and until 2050:

- Facilities that expect to be flaring and/or venting after 2030 are identified from the 2023 UKSS responses.
- Historic trends of routine flaring and venting for these facilities are calculated using NSTA flaring consents application data.

- A predicted proportion of routine flaring/venting from 2030 to 2050 in a baseline scenario is assigned to each facility using the trends calculated.
- Future installation level emissions are attributed to routine flaring/venting and subtracted from the total flaring/venting emissions profile.
- NSTA assumes likely progress in achieving ZRFV between 2025 to 2030 and builds an arbitrary tapering of emissions abatement from 2025 to the peak of annual abatement in 2030. This is undertaken by assigning 20% of the peak to 2026, 40% to 2027, 60% to 2028 and 80% to 2029.
- The above-calculated ZRFV values are then subtracted from the mid-case electrification scenario to project combined. abatement.

Emissions intensity

Emissions intensity measures the overall amount of GHGs (carbon dioxide, methane and nitrous oxide) emitted to produce each barrel of oil equivalent, comprising the following:

- 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).

Notes:

While GHG intensity is a more complete calculation, it relies on detailed non-CO_2 GHG emissions data which can vary in quality.

International Upstream Emissions Intensity Benchmarking

To benchmark the UK's upstream emissions performance, data from Rystad Energy is used to compare upstream production only carbon and methane intensities against other hydrocarbon-producing countries.

Notes:

- Benchmarking of 88 countries representing countries with production greater than 10,000 boe/day.
- Non-carbon dioxide GHGs have been converted to carbon dioxide equivalent (CO_2e) units using GWP 100-years, AOR5.
- Emissions intensity figures detailed in Figure 18 for the UK and other countries exclude emissions produced by onshore terminals and midstream and downstream activities, therefore the intensity figures relate solely to emissions generated at the oil or gas field.
- Rystad Energy's upstream methane emissions data is a proprietary, field-by-field emissions inventory database combining asset-level reported data (in regions where available), quality aggregated reported data (e.g. company and regional level), methane satellite data, and satellite flaring data (based on VIIRS Nightfire, Colorado School of Mines). Due to relatively sparse and low data quality in the public domain, Rystad Energy's bottom-up methane estimates by definition do not represent total emissions inventories from the industry, but rather emissions that can be allocated to individual fields based on reported data, facility overviews, and satellite measurements.
- Emissions intensities at country level conceal the great extent of in-country variation in emissions intensity at field level. Some of this variation is related to the phase in the life cycle of each field, with late-life emissions intensity rising exponentially as production rates decline and CoP approaches.

North Sea Transition Authority

The North Sea Transition Authority is the business name for the Oil and Gas Authority, a limited company registered in England and Wales with registered number 09666504 and VAT registered number 249433979.
Our registered office is at Sanctuary Buildings, 20 Great Smith Street, London, SW1P 2BT.

www.nstauthority.co.uk