Global Flow Measurement Workshop
24-26 October 2023

Technical Paper

Regulation & Stewardship of Fiscal Metering, Emissions Measurement, & Measurement for CCUS in the U.K. Sector of the North Sea

Douglas Griffin, U.K. North Sea Transition Authority

1 INTRODUCTION

This paper will summarise the current U.K. regulatory Guidelines for fiscal measurement in the upstream oil & gas sector, which have been in effect since 2020. It will then set out the expectations of the North Sea Transition Authority (NSTA) regarding the measurement of direct (Scope 1) greenhouse gas (GHG) emissions from oil & gas production on the U.K. Continental Shelf (UKCS) – including expectations regarding Operators' Emission Reduction Action Plans (ERAPs). Finally, the paper will discuss the NSTA's requirements and expectations with regard to measurement of carbon dioxide in Carbon Capture, Utilisation & Storage (CCUS) applications..

2 FISCAL OIL & GAS MEASUREMENT

An Operator's Licence to produce hydrocarbons on the U.K. Continental Shelf (UKCS) contains the 'Measurement Model Clause', which states that

> *"The licensee shall measure or weigh, by a method or methods customarily used in good oilfield practice, and from time to time approved by the Minister, all petroleum won and saved from the licensed area."*

Responsibility for the regulation of oil & gas production on the UKCS currently lies with the North Sea Transition Authority (NSTA), as the Oil & Gas Authority (OGA) was renamed in 2022. The OGA was itself founded in 2015, taking over its regulatory role from the Department of Energy & Climate Change (DECC). In contrast to DECC and its predecessors as regulators of the upstream oil & gas industry in the U.K. (among them the Department of Trade & Industry & the Department of Energy), OGA/NSTA are not U.K. Civil Service organisations, but arms-length 'Government Companies'.

The current NSTA Measurement Guidelines date from 2019. No change has taken place since then; nor is any change currently envisaged. The 2019 guidelines ('Issue 10') differ significantly from the previous DECC document ('Issue 9', 2014), reflecting the new regulatory approach taken by the OGA/NSTA and also the changed fiscal regime for the upstream oil & gas industry.

Since Petroleum Revenue Tax (PRT) was set to zero (with permanent effect) in January 2016, the tax system in the upstream sector of the U.K. oil & gas industry has effectively been uniform; any fiscal impact of mismeasurement in pipeline allocation systems is now second-order in nature and relates to eventual decommissioning tax relief on formerly PRT-liable fields. Corporation Tax is company-based rather than (like PRT) field-based and is paid on profits, which are ring-fenced for offshore operations [1]. Consequently, the regulatory interest in fiscal metering has moved towards surveillance of measurement stations at which hydrocarbons are sold, and profits generated.

The key features of the current approach are as follows:

(i) The Licensee must agree a 'method of measurement' (as referred to in the Measurement Model Clause above) with NSTA as per the long-standing Petroleum Operations Notice No. 6 ('PON 6') process prior to the start-up of any new field, or in the event of significant changes to an existing, already agreed method of measurement.

(ii) For pipeline-export systems – whether oil or gas – NSTA expects Operators of the pipeline entry-point measurement stations to be able to show that the relevant pipeline entry requirements are being met. NSTA periodically liaises with the respective pipeline Operators (either in bespoke reviews or by participating in annual pipeline meetings) in order to satisfy itself that 'good oilfield practice' is being followed. NSTA's inspection of offshore measurement stations is generally limited to those pipeline systems that are shared with Norway, since here there is potential for loss of UK revenue. NSTA inspections are primarily aimed at the measurement stations at pipeline terminals, as this is where the quantities of hydrocarbons sold (and hence tax raised) are determined.

(iii) For allocation metering at a sub-pipeline-entry level, NSTA expects Operators to be able to demonstrate that the method of measurement has been agreed to by all interested parties in the allocation system; NSTA can if required play the role of 'arbiter' in the event that one or more such parties feel disadvantaged.

(iv) For offshore-loading systems, much depends on where the point of sale of the crude oil (and hence the point at which tax is raised) lies. Where cargoes are sold in the field, the offshore measurement should meet custody-transfer standards. Where sale takes place at the port of discharge, Operators are expected to report the offshore 'bill of lading' and the terminal 'out-turn' to NSTA at regular intervals and to follow up on any systematic discrepancies as required.

3 MEASUREMENT OF GREENHOUSE GAS EMISSIONS

The NSTA has relatively few direct regulatory powers with respect to emissions of GHGs, but it does have a key 'Stewardship' role to play in helping Operators to reduce these emissions and to ensure that the targets set by the North Sea Transition Deal (NSTD) are met.

This part of the paper sets out the Regulatory and Reporting requirements on Operators before turning to NSTA's expectations regarding the associated measurement of GHG emissions.

3.1 The Regulatory & Reporting Background

<u>The North Sea Transition Deal</u>

The North Sea Transition Deal was agreed between Government and Industry in March 2021. As part of the deal, Industry committed to reductions in Scope 1 GHG emissions of 10% by 2025, 25% by 2027 and 50% by 2030, with respect to the 2018 baseline figures. (Scope 1 emissions are defined as "direct" emissions, in this case from oil & gas production on the UKCS. Included are emissions from power generation, flaring and venting, as well as "fugitive" emissions of GHGs.) Overall, a 60Mt reduction in these GHG emissions is to be delivered over the period to 2030. (For context, total Scope 1 emissions of GHGs from the UK upstream oil & gas sector are currently estimated at 14.5Mt/yr. [2])

Note that these targets apply to the basin as a whole, and not to individual assets.

<u>The UK Emissions Trading Scheme (UK-ETS)</u>

Emissions of $C0_2$ from power generation and flaring normally fall within the scope of the UK Emissions Trading Scheme (ETS), which requires emissions of $C0_2$ to be reported annually. For the UK's upstream oil & gas sector it is administered by the Offshore Petroleum Regulator for Environment & Decommissioning (OPRED), a branch of the UK Department for Energy Security and Net Zero).

<u>The Environmental & Emissions Monitoring Scheme (EEMS)</u>

Offshore Operators report their annual emissions of GHGs to OPRED via the Environmental and Emissions Monitoring System (EEMS).

The relevant GHGs are carbon dioxide ($C0_2$), methane (CH_4) and nitrous oxide (N_20). Each of these has a different 'global warming potential' (GWP), which is defined as the amount of energy that one unit of mass of a gas will absorb over a given period of time, relative to the same mass of $C0_2$. The GWP figures used by NSTA for CH_4 and N_20 are 28 and 298, respectively, representing the heating effect of these gases over a 100-year time frame. This allows total GHG emissions to be aggregated and expressed in terms of 'carbon dioxide equivalent' ($C0_2e$), allowing the emissions from different UKCS hubs to be compared and benchmarked on a like-for-like basis.

> *Worked example:*
> An offshore installation has the following annual GHG emissions:
> $C0_2$ – 100,000t GWP = 1
> CH_4 – 25,000t GWP = 28
> N_20 – 2,500t GWP = 298
> Total GHG emissions = 100,000 + 30,000*28 + 2,500*298 = <u>870,000t $C0_2e$</u>

<u>Stewardship Expectation No. 11 (SE11) & Emissions Reduction Action Plans (ERAPs)</u>

The 'OGA Strategy', which was refreshed in 2021, sets out a number of requirements on UKCS Operators and Licensees. Principally, under the 'Central Obligation' they are obliged to maximise the expected net value of economically-recoverable petroleum from relevant UK waters, and also

> *"to be proactive in identifying and taking the steps necessary to reduce their greenhouse gas emissions as far as reasonable in the circumstances"*

In consultation with Industry, NSTA has developed a series of 'Stewardship Expectations' on UCKS Operators and Licensees, covering a variety of topics such as Joint Venture Hub Strategy, Integrated Field Management and Technology

Deployment. In March 2021, a Net Zero Stewardship Expectation (SE11) was published. Amongst other things, it requires Operators and Licensees to "invest in and deploy appropriate GHG emissions-monitoring technologies", and to develop Emissions Reduction Action Plans (ERAPs).

Operators are expected to have ERAP documents available for review by NSTA. There is no set format for the content of these documents. However, they may be expected to contain information on the following:

- An estimation of current GHG emission levels, and an assessment of the uncertainties with which these have been determined.
- Indications of how emission reduction is given a key place in business processes (for instance, through the use of relevant KPIs).
- Details of planned emission-reduction projects that have received budget approval, and the expected emissions reductions that will result.
- A review of previous projects, with details of whether they ran to budget, and delivered the expected reductions in GHG emissions.

NSTA annually determines GHG emissions from each offshore UKCS hub using the latest EEMS data, in order to benchmark higher-emitting assets and prioritise Stewardship Reviews with the relevant Operators. Combined with production data, emissions intensities can be calculated for each hub, indicating the mass of GHGs emitted for each barrel of oil equivalent (boe) produced.

<u>Flare & Vent Consents</u>

NSTA manages a system of consents for flaring and venting, which strictly limits the amount of gas that an Operator may flare or vent during the consenting period (which is generally 12 months, although it may be shorter). *Note that the consents apply to the mass of gas flared or vented, and not to the resultant emissions.*

Operators must report to NSTA quantities of gas flared and/or vented on a monthly basis; these totals must not exceed the totals set for the consenting period (typically annual) and Operators must approach NSTA as soon as it becomes clear that the consented amount is on course to be breached.

The NSTA and its predecessor organisations have administered the consent system with a view to reducing quantities of gas flared and vented on the UKCS; reported figures of gas flared indicate a reduction of around 50% between 2018 and 2022, while reported emissions of methane reduced by around 40% between 2018 and 2021 [2]. The UK is among the signatories to the World Bank's Zero Routine Flaring initiative [3], which commits assets to cease routine flaring by 2030 at the latest. ("Routine flaring" is defined as "flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market", i.e. it does not include safety flaring or, for instance, flaring during process upsets.) Flaring levels may therefore be expected to decrease further.

Since 2021, quantities of 'cold-flared' gas (i.e. gas delivered to the flare line during periods in which the flame has been extinguished) have been reported as vent, rather than flare.

3.2 NSTA's Expectations on Measurement of GHG Emissions

The measurement requirements relating to the above reporting systems are summarised in the table below.

Table 1 – Existing Measurement Requirements

Reporting Requirement	GHG Emissions	Authority	Measurement Uncertainty	Verification
EEMS	$C0_2$, CH_4, N_20	OPRED	Not defined	None
UK-ETS	$C0_2$	OPRED	Power - ±2.5% Flare - ±7.5%	Annual, by appointed 3rd-party verifier
NSTD	$C0_2$, CH_4, N_20	NSTA	Not defined	None
Flare Consent	n/a (applies to gas flared, not to emissions)	NSTA	Not defined	None

Clearly, there is an expectation that the measurement of GHG emissions should be reliable, if the basin's progress in reducing GHG emissions is to be meaningfully assessed. In terms of 'hard regulation', NSTA relies on the verification mechanism within the ETS. Emissions of $C0_2$ from power generation typically comprise around 80% of GHG emissions; the measurement conditions in fuel gas applications are generally fairly benign, and the measurement target of ±2.5% should be readily achievable. However, it is far from simple to demonstrate that the ±7.5% uncertainty requirement on flare gas can be met, given the inherent lack of traceability. In custody-transfer applications, the flow meter can be removed and recalibrated at a test facility against a reference meter that is traceable to national standards, and where the calibration conditions are representative of those experienced by the meter in service. This is not possible for flare applications, so that installation effects on the meter must be estimated, with all of the additional – sometimes unquantifiable – uncertainty that this entails. Fortunately, flaring levels are set to decrease further on the UKCS, as a result of commercial and societal pressures, and the Zero Routine Flaring initiative referred to above.

In flare gas applications NSTA considers that rather than focus on uncertainty targets that may be difficult or impossible to verify, it makes more sense to require Operators to follow 'best practice' in the installation and operation of flare gas meters [4]. 'Best practice' in this context may, for example, mean:

- Periodic verification of flow meter parameters.
- Demonstration of traceability of flow calculations.
- Assessment of effect of flow profile on meter performance via Computational Fluid Dynamics (CFD) modelling. [5]
- Review of meter size vis-à-vis typical flow rates encountered by the meter in service.

In summary, NSTA shall encourage Operators to employ some of the familiar approaches developed in custody-transfer applications, while accepting that comparable levels of measurement uncertainty will not be achievable.

In July 2023, an expansion of the scope of the ETS was announced; included now are emissions of $C0_2$ from the venting of process plant (such as amine units) in the upstream oil & gas industry. In addition, the administrators of the ETS formally announced that they will "work to include methane emissions from the upstream oil & gas sectors".

As a result, it may become necessary to determine the combustion and/or destruction efficiency [6] of flare gas systems, i.e. the present approach of assuming a combustion efficiency (CE) of 98% may no longer be considered acceptable. Since the GWP of methane is 28 times that of $C0_2$, the total amount of GHG (in units of $C0_2e$) emitted as a result of flare operations is highly sensitive to the efficiency of combustion of the gas delivered to the flare. Ideally, the CE should be 100%, so that all the methane in the flare line is converted to $C0_2$. In practice, the CE will be lower than this. Recent research [7] has highlighted the factors – for instance, low flow rate and/or high ambient wind speed – that can adversely affect combustion and destruction efficiency. NSTA may in future require Operators to make use of new technologies that allow the combustion efficiency to be modelled in real time, so that the flare may be operated with a view to minimising total GHG emissions. This may lead to the adoption of counter-intuitive operating practices; in some instances (for example, with high ambient wind speeds) it may be preferable to *increase* the amount of hydrocarbon gas flared, in order to maximise combustion efficiency.

> *Worked example:*
> 1.0t of CH_4, if combusted perfectly, results in ~2.7t $C0_2$.
> 1t CH_4 ≡ 28 t $C0_2e$.
> Scenario 1 – **100t CH_4** delivered to flare; 2% uncombusted. Total GHG emissions = (98*2.7) + (2*28) = **320.6t $C0_2$ e**.
> Scenario 2 – **110t CH_4** delivered to flare; 1% uncombusted. Total GHG emissions = (99*2.7) + (1*28) = **295.3t $C0_2$ e**.

The inclusion of methane in the UK-ETS may render very financially significant any calculation of combustion efficiency – in the event that such calculations are accepted by OPRED - and NSTA therefore anticipates that this area will attract a good deal of attention; there would be significant financial incentives for the adoption of real-time models for flare operation, allowing the emissions of methane to be minimised in response to changing ambient conditions, in particular wind speed [7].

The 'OGMP 2.0' scheme [8], run by the UN's Environment Programme, is a "measurement-based framework reporting framework for improved accuracy and transparency of emissions reporting". Accredited companies must commit to establishing methane reduction targets by 2025. 5 levels of accreditation are available; Levels 1-3 are where estimates of emissions are based on generic emissions factors; Level 4 features direct measurement "or other technologies", while Level 5 additionally features integration of "bottom-up", source-level reporting with independent site-level measurements (e.g. drone surveys). NSTA anticipates that UKCS Operators will wish to work towards Level 4 or Level 5 accreditation; amongst the benefits that this should yield, one may mention improved uncertainty in reported fugitive emissions.

4 Measurement of $C0_2$ in CCUS Applications

NSTA has a regulatory role in the fast-developing CCUS industry in the North Sea – for instance, it issues the relevant carbon-storage licenses and will be involved in subsequent reservoir-monitoring activities.

There are two main requirements for measurement of $C0_2$ in CCUS applications:

- Bulk quantities of $C0_2$ stored must be determined for accounting purposes (the relevant carbon credits – which provide the financial basis for CCUS – are payable based on these figures).
- Quantities of $C0_2$ stored at each injection point must be determined for reservoir management purposes.

Composition of the bulk fluid must also be determined, for the purposes of both accounting (carbon credits relate only to stored quantities of $C0_2$, and not to any impurities) and flow assurance - the injected fluid will typically be in the super-critical phase, and the presence of even minor amounts of certain contaminants could have very serious flow assurance implications.

A document setting out NSTA's regulatory expectations with respect to $C0_2$ measurement in CCUS applications is currently in preparation [9]. Essentially, bulk quantities will have to be determined to within the uncertainty requirements of the UK-ETS (i.e. ±2.5%) or better. It is anticipated that this will typically be achieved via Coriolis or orifice meters, but the use of ultrasonic meters is not ruled out. Plans for a traceable calibration facility, allowing meters and sampling systems to be calibrated on dense-phase $C0_2$, have recently been announced; the facility is expected to be ready by 2025 [10]. The nature of NSTA's regulatory role in approving or inspecting the relevant measurement & sampling systems has still not been determined. However, it may be anticipated regulatory requirements, from NSTA or the pipeline operator or both, will be more rigorous than the annual verification exercise required by the UK-ETS.

The NSTA's approach to the measurement uncertainty at well injection points will be similar to that taken in analogous oil and gas applications; i.e. it will be non-prescriptive, and based not on any uncertainty requirement (with which it may in any case be difficult to demonstrate compliance, especially in sub-sea applications) but rather on the adoption of good industry practice.

5 REFERENCES

[1] Tax revenues from the upstream oil and gas sector rose from £300m in 2020/21 to £2.6bn in 2021/22, and are expected to reach £11bn in 2022/23. https://researchbriefings.files.parliament.uk/documents/SN00341/SN00341.pdf
[2] NSTA Emissions Monitoring Report, 2023.
[3] https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030
[4] As set out, for instance, in Energy Institute Standard HM 58 - *Guidelines for determination of flare quantities from upstream oil and gas facilities* (currently under review).

[5] For instance, BLACK, A., LAING, M., NEWMAN, D.; Metering and emission analysis of flare and vent metering systems using Computational Fluid Dynamics; Global Flow Measurement Workshop, Aberdeen 2022.

[6] Combustion efficiency (CE) refers to the proportion of gas in the flare that is oxidised to $C0_2$; destruction efficiency (DE) refers to how much of a particular component is removed, without reference to whether this is via oxidation or some other process. Thus, the figure for the CE can never be higher than the DE.

[7] See, for instance, STOCKTON, P. & PEEBLES, R.; Offshore flares: measurement and calculation of combustion efficiency, methane and CO_2e emissions; Global Flow Measurement Workshop, Aberdeen 2022.

[8] https://ogmpartnership.com/

[9] Guidance Notes for Measurement of Carbon Dioxide for Carbon-Storage Permit Applications, NSTA *(in preparation; anticipated publication date December 2023).*

[10] https://cordis.europa.eu/project/id/101094664