# New Challenges in Oil & Gas Measurement

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## Introduction

The topics covered in this short paper by no means represent an exhaustive list. However, some of the major oil and gas measurement issues arising from the development of the remaining reserves in the UK sector of the North Sea are presented from DECC's perspective.

The purpose of this paper is to stimulate discussion in these areas at this year's workshop, as well as to clarify DECC's position in one or two key areas.

## Traceable Liquid Density Measurement

Approximately 5 years ago, a fairly major shortcoming in the existing practices surrounding the calibration of liquid densitometers came to light. In a paper presented at the 2007 North Sea Flow Measurement Workshop, the problem was summarised as follows:

> *"However, the calibration of most industrial densitometers is undertaken using fluids whose physical characteristics are significantly different to the actual working or operational fluids. Additionally, the range of pressures and temperatures at which the instruments are normally calibrated is limited to near ambient conditions but many densitometers, particularly those used in offshore applications, operate under high pressure, high temperature conditions. This can be a significant source of error in density measurement. Ideally, calibration should be undertaken at metering pressures and temperatures using fluids whose volumetric properties are known accurately across the full temperature and pressure range required for the calibration."* [1]

A Joint Industry Project (JIP) completed its work earlier this year and a report was circulated to the project members for their review. The consultation period has now concluded.

The report contains a number of recommendations whereby the integrity and traceability of the overall calibration process will be greatly improved. Unfortunately, the implementation of these recommendations will require significant modifications to the existing calibration facilities. This will take time, as well as a significant investment on the part of the operators of these facilities. DECC, as UK Regulator, cannot reasonably ask oil companies to implement the new calibration procedures while no appropriate calibration facility exists. At the same time, it is only through some sort of regulatory stimulus that the required modifications to the calibration facilities will be made.

To this end, a statement will be published on the DECC website, outlining the recommendations of the JIP and the new calibration procedures that it expects to see followed after an 18-month ‘period of grace’. It is understood that this period will give the operators of the calibration facilities sufficient time in which to make the necessary modifications.

**Calibration Uncertainty**

One of the basic principles of uncertainty analysis is that parameters contributing less than a tenth of the overall uncertainty may be conveniently ignored. From this, the following basic metrological principle naturally arises:

> *When calibrating a measuring device, the uncertainty of the calibration standard should be a factor of 10 less than that of the device itself.*

Thus, when calibrating a temperature transmitter to ±0.5°C, the uncertainty of the calibration standard should be ±0.05°C or less. Any inherent bias in the certifying authority’s temperature standard is small enough to be safely ignored.

This basic principle should of course be familiar to any flow metering engineer. In practice, however, flow metering engineers are occasionally forced to turn a blind eye to this principle in view of the lack of any practical alternative. The impact of such a decision must nevertheless not be overlooked.

Let us now consider two such examples from practice.

- Gas Ultrasonic Meters

  In North Sea applications of 10-15 years ago, custody-transfer measurement of gas flowrate made use of orifice plate technology, and virtually nothing else. The design uncertainty of such systems is typically ±1.0%. Since orifice plates designed and installed to ISO 5167 do not need to be flow calibrated, there was never any need for a calibration facility with an uncertainty of 0.1%.

  Today, of course, the situation is very different. The use of ultrasonic meters for custody-transfer gas flow measurement has understandably become widespread. One of the features of these devices, as well as their facility to provide detailed diagnostic information, is their relatively low measurement uncertainty. Multi-path meters have uncertainties in the range of 0.2%. However, they require flow calibration. From the above, it is clear that for true flow calibration to take place, calibration standards with flow uncertainties in the region of 0.02% are required. Unfortunately, such facilities do not presently exist – at least, not at the required flowrates.

  Thus, in the absence of any practical alternatives, the basic principle referred to above is ‘bypassed’. Ultrasonic meters are routinely ‘calibrated’ against flow standards whose uncertainty is not significantly lower than the meters themselves. While the adoption of such practices is wholly understandable, as said above *the consequences of ‘bypassing’ established metrological principles must not be overlooked*. In contrast to situation with the temperature transmitter, an inherent bias in the certifying authority’s standard has the potential here to be very significant. Operators are of course aware of this and this explains the tendency to returning ultrasonic meters to the same laboratory throughout their life in service.

There is clearly a continued place for the practice of ‘flow-calibrating’ ultrasonic meters. Even a condition-based monitoring scheme requires an initial flow calibration. *However, great care should be taken when interpreting the results*; in particular, the uncertainty and repeatability of the calibration facility must always be considered when the results of the calibration are used in mismeasurement calculations.

- Multiphase Meters

  Equally, great care must be taken when evaluating the performance of multiphase meters by placing them in series with test separators and comparing the single-phase flowrates obtained. It is by no means clear that multiphase meters’ uncertainties are any higher than the test separators. It is most definitely *not* the case that test separators’ uncertainties are an order of magnitude lower. Nevertheless, many commercial contracts require multiphase meters to be adjusted to agree with test separator measurements if a ‘trigger’ level (typically ±5% per phase) is exceeded.

  Here too DECC recognises that comparison between multiphase meters and test separators may be the best practical option, and can provide valuable information, perhaps allowing drift in multiphase meter performance to be detected. But the fact that basic metrological principles have been by-passed should never be overlooked, and any commercial contract requiring adjustment of one measurement to agree with the other should be treated with great caution.

**Cost v Benefit in Calibration Activities – Condition-Based Monitoring**

The above considerations have led DECC to reconsider its position on calibration activities in general.

North Sea operators face a continual challenge to keep operating costs low. While the costs associated with the routine calibration of each of the elements of a fiscal metering system are undoubtedly clear, the associated benefit is not always understood. This is not a desirable situation. Where the benefit is clear, the likelihood of such activities being overlooked is reduced.

Calibration takes place in order to detect any systematic shift that may already have occurred in the device under test. In any fiscal measurement system, such a shift will have financial consequences. These consequences may be very significant, they may be trivial, or they may be somewhere in between. When weighing up the benefits of a calibration program, one must consider the likely position on this ‘spectrum’ of any shifts that may occur, and the likelihood of their occurrence. This is standard risk-analysis strategy – the key parameter is the product of the consequences of an event occurring and the probability that it will actually happen. In our field we commonly use the term ‘exposure’ for the ‘financial risk’ arising from mismeasurement.

How are these key parameters – probability of a shift, and its likely scale – to be determined in practice? Ultimately this must be based on the service history of the device in question, although to some extent the performance of similar devices elsewhere should be borne in mind. Ultimately, however, this is an area where hard-and-fast rules are difficult to construct – it comes down to the judgement of measurement specialists.

One the exposure has been determined, this may be compared with the cost of removal and recalibration. On the basis of this comparison, the appropriate interval between successive calibrations may then be agreed following discussion with the Regulator. One of the attractions of this approach is that the benefits derived from the calibration are made explicit. Calibrations should be seen to be in Operators' own interest, rather than being done simply because they are required by the Regulator or by the pipeline authority.

DECC considers that such a risk-based approach to routine calibration programmes should have an important part to play in Operators's maintenance strategies in the remaining years of North Sea production.

**Multiphase and Wet Gas Measurement**

It should be no surprise to find these topics included in a paper entitled 'New Challenges in Oil and Gas Measurement'. Multiphase, and its subset, wet gas measurement, have dominated the programmes of North Sea Flow Measurement Workshops for the last decade. Their use in fiscal applications is now widespread. This is partly a reflection of the improved performance and reliability of multiphase flowmeters, but it primarily reflects the smaller size of oil and gas fields being developed in the North Sea, and the need to make fiscal measurement prior to the fluids being separated into their constituent phases.

The charts in Appendix 1 have been presented by DECC and its predecessor organisations at a number of forums in Aberdeen over the past decade, but they are perhaps worth presenting again at the North Sea Flow Measurement Workshop, as they illustrate why it is necessary to develop satellite fields sooner rather than later.

One of the key challenges facing the North Sea flow measurement industry is the need to expand the range of the correlations used in wet gas applications. There is widespread knowledge of correlations such as that first published by de Leeuw in 1997 [2]. However, like all such correlations this was never intended to be used over the full range of conditions routinely encountered in the North Sea. It has been widely used well beyond its intended pressure range, on fluids that are not representative of those that were used in its derivation. Once again, the justification for doing so has been the lack of any reasonable alternative. This does not mean that we should lose sight of the fact that mismeasurement will result. To some extent, the 'acceptability' of such an approach – which is apparent rather than real - has reduced the drive to expand the areas of the pressure/temperature/GOR matrix covered by the existing correlations. To help address this to some extent, the UK Government is funding ongoing research in this area. [3]

The need to derive additional confidence in the verification of multiphase meters is as keenly felt as ever. As highlighted earlier in this paper, there are shortcomings associated with the current standard strategy of comparison between multiphase or wet gas meter and test separator. Additional verification methods such as data reconciliation techniques or the use of 'virtual' models have the capability to build confidence in these performance of these meters.

**Sampling of Liquid Petroleum**

Sampling of liquid petroleum has lost none of its importance with the increasing age of the North Sea. On the contrary, with increasing levels of water production, determining the true water content of contributing fields in shared transportation systems is more challenging than ever before. This is especially true since the advent of HT/HP condensate fields and the associated difficulties of determining the water content of condensate samples.

The operator of at least one major North Sea pipeline has correlated pipeline imbalance with platform shutdowns. Since large quantities of water are often produced following field shutdowns, this finding probably confirms the suspicion of many that the principal cause of pipeline imbalance is failure to detect quantities of water entering the pipeline. The consequences of such a failure are often particularly inequitable, since the apparent 'loss' typical of liquid pipeline systems is attributed to fields on the basis of their throughput. Newer fields, which are by their nature 'drier', are often relatively high producers. They are therefore allocated a correspondingly high share of the pipeline 'loss', despite the fact that the source of the loss probably lies with older, 'wetter' fields.

The operator of at least one major pipeline in the UK sector of the North Sea has surveyed relevant liquid sampling systems to determine the level of compliance with ISO 3171. DECC does not believe that a sampling system should stand or fall on its performance relative to this standard; there have been instances where apparently well-designed sampling systems have failed to meet the 'homogeneity' criteria of Appendix A by several orders of magnitude(!). To determine the degree of homogeneity of the fluid at the sampling point, it is preferable to carry out a CFD study that takes account of the specific characteristics of the sampling system - for example, whether the flow is horizontal or vertical at the sampling point.

Of course, the sampling system itself is only part of the problem. Failure to return samples in their correct condition to the onshore laboratory for analysis results in the use of water content values determined in offshore laboratories, often in less-than-ideal conditions and often by personnel who are less well-qualified than their onshore counterparts. While it is unreasonable to expect 100% return rates, it does appear that sample collection and return is not always given the priority it deserves. The penalties for failing to return samples for analysis are often minimal, and current procedures may actively benefit operators who fail to return samples with high water contents. DECC strongly encourages pipeline operators to look at the level of incentivisation that exists in current transportation agreements, as this is an issue that may reasonably be expected to increase in significance as the North Sea province continues to mature.

**Commercial Contracts and Measurement Uncertainty**

As we have seen , today the North Sea is a mature province, the development of small sub-sea satellites over existing infrastructure is very much the norm.

The 'traditional' method of doing this is to allocate production to the satellite field(s) directly, perhaps by well test, more often (these days) by continuous measurement by multiphase meter or, more rarely, via dedicated separator(s). The 'host' field is allocated the out-turn from the platform, less the quantities allocated to the satellite field(s), adjusted via a process model to take account for changes in phase behaviour as the fluids pass through the plant.

The uncertainty associated with any 'by difference' measurement depends on the uncertainty of the directly-measured quantities, and the relative proportions of the sum of these to the 'by difference' amount. Ideally, the 'by difference' quantity should be a small proportion of the total. Given that it is the 'host' field that is normally allocated on a 'by difference' basis, and given that the host field will necessarily have been in production for longer than any of the satellites, this ideal scenario is not always the case. The quantities produced by the host field may instead be a small, and rapidly diminishing, fraction of the total.

This problem will inevitably be exacerbated whenever a further satellite is developed across the host facility; the uncertainty in the amount allocated to the host field will inevitably increase.

In the UK sector of the North Sea, where a host field has been in production since 1993 there is a high probability that it will pay tax at a higher rate than its newer satellites, so there is a direct fiscal dimension to this allocation process. DECC and its predecessors have generally been fairly relaxed when it comes to giving consent to such developments; while financial exposure is increased, the higher uncertainty in the allocation to Petroleum-Revenue-Tax-paying fields has generally been seen as a price worth paying in order to help ensure the development of the remaining reserves in the UK sector of the North Sea.

It has to be said that commercial operators have not always been so philosophical.

There have been a number of occasions on which the operators of the host facility have sought financial compensation, in advance, from the partners of prospective satellite fields. On more than one occasion the subsequent commercial wrangling has come very close to preventing the development of a satellite field from taking place. Such a practice can only arise from a misunderstanding of the nature of measurement uncertainty and its impact on financial exposure, and it is to be strongly discouraged.

Another possible scenario is where the Operator of the 'host' facility holds equity in both 'host' and 'satellite' field. In such cases the exposure of this Operator may be relatively small, since any under-allocation to one field will be compensated for by an over-allocation to the other. However, where other equity-holders have interests in only one of the fields, the financial exposures, and resultant willingness to invest in robust measurement and allocation systems, may not be aligned between all the interested parties. This too has the potential to cause commercial tensions.

DECC hopes that these and other scenarios will be addressed in the coming years, perhaps by means of a joint Operators' forum (perhaps under the auspices of UK Oil

& Gas); the issues involved have the potential to jeopardise the successful recovery of some of the remaining reserves in the UK Sector of the North Sea.

## REFERENCES

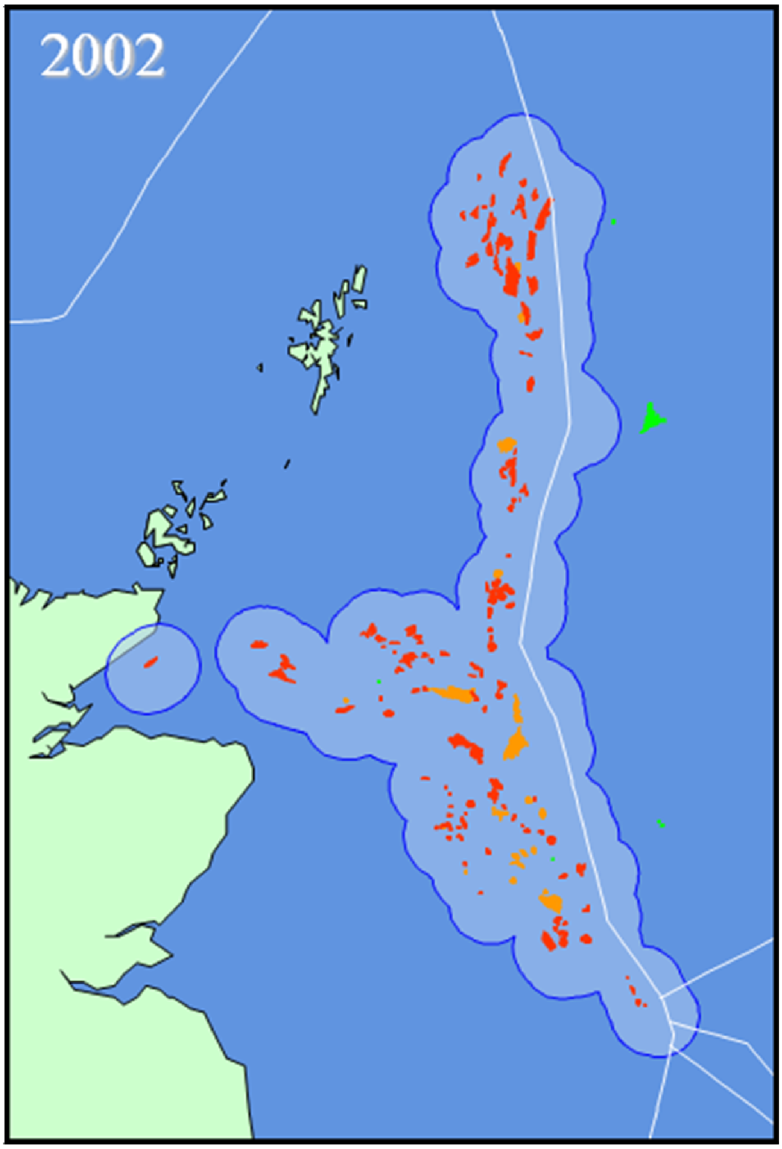
[1] **GLEN,N & GRIFFIN,D** Traceable Calibration of Liquid Densitometers. North Sea Flow Measurement Workshop, Gardermoen 2007

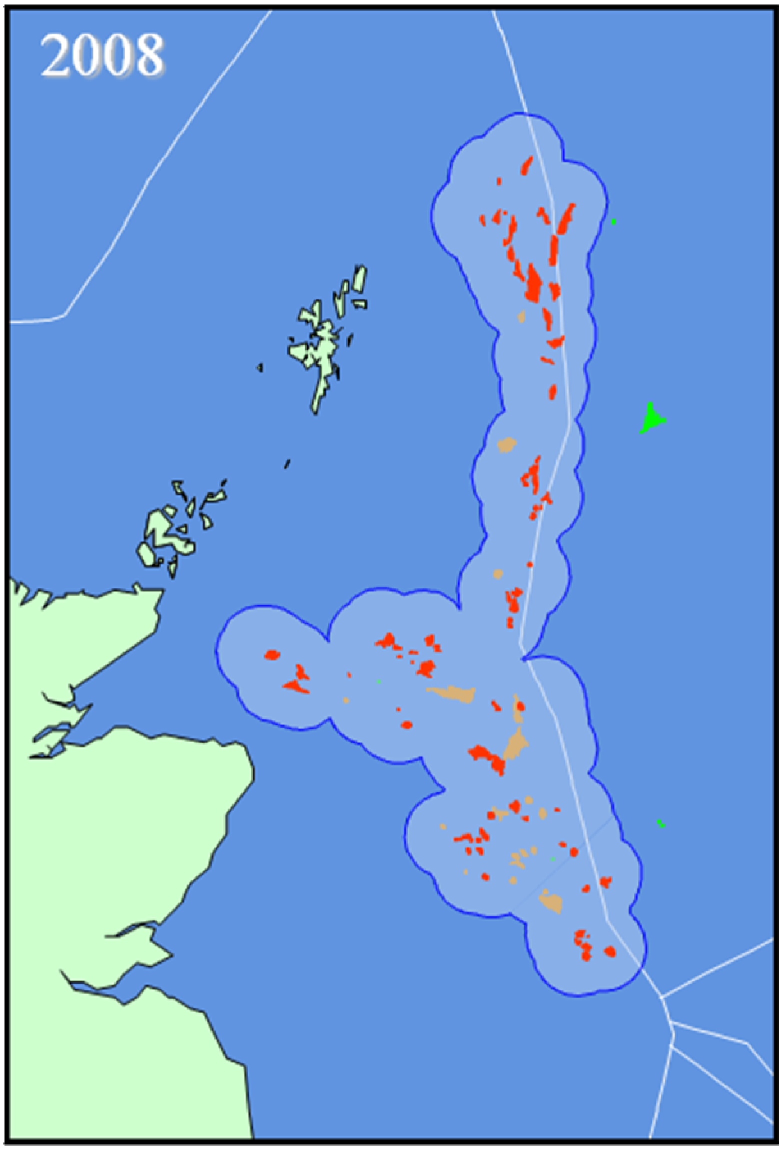
[2] **DE LEEUW, R** Liquid Correction of Venturi Meter Readings in Wet Gas Flow, North Sea Flow Measurement Workshop, Kristiansand 1997

[3] Project funded by the Department of Business and Innovation's Engineering & Flow Programme (http://www.nmo.bis.gov.uk/content.aspx?SC_ID=489).

**APPENDIX**

The red and orange areas charts are producing oil and condensate fields respectively. Around each field a tie-back 'bubble' of *c*.50km has been drawn. Projections for field life have been applied, allowing us to identify the diminishing extent of the areas of in which satellite tie-backs will have the potential to be developed.

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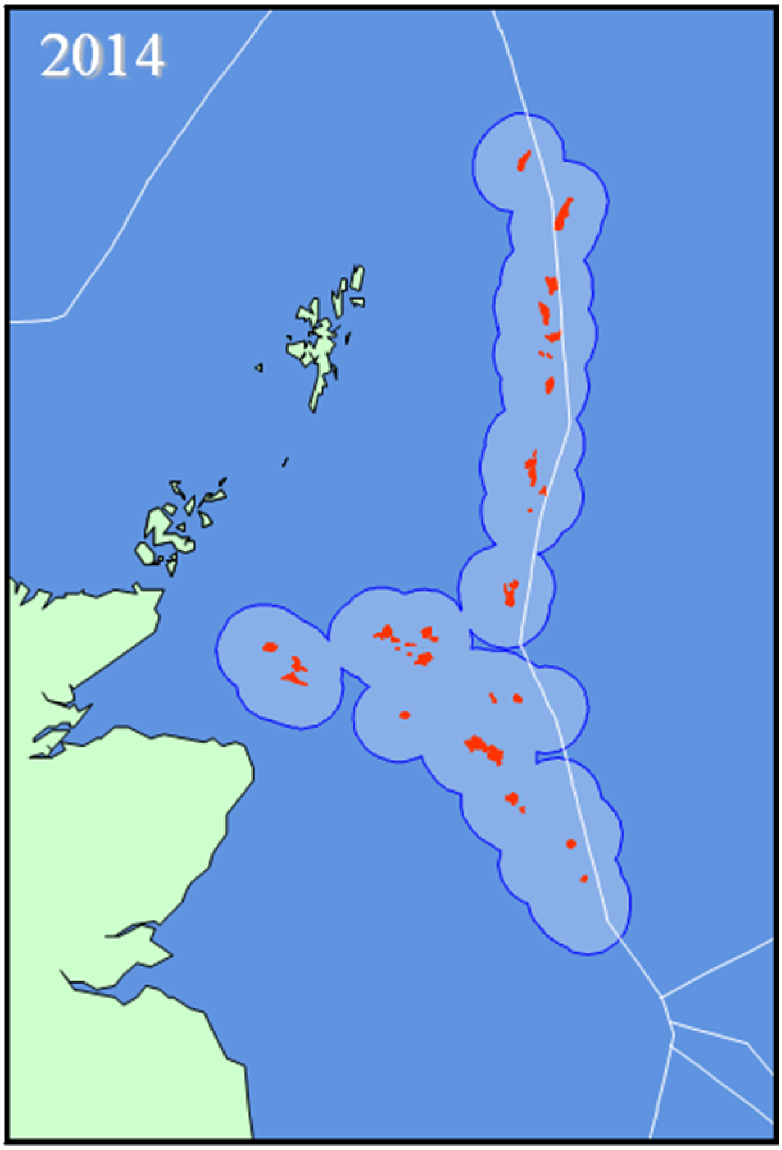
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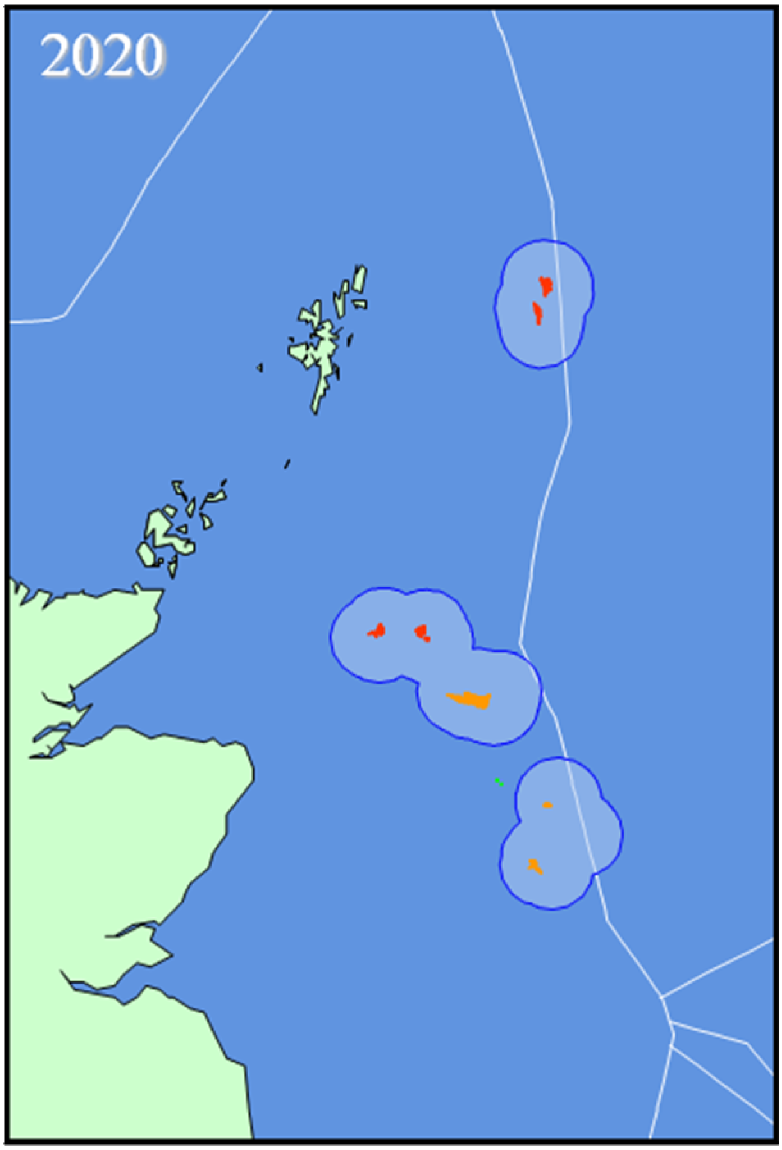
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