The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended)

Notice Pursuant to Regulation 10(2)

Siccar Point Energy E&P Limited
Cambo Field Development

Whereas the Secretary of State has been informed of additional information relating to the letter of application for consent submitted to the Oil and Gas Authority in respect of the above named project, which was supported by an Environmental Statement (D/4240/2019) submitted to the Department on 29th October 2019 and was subject to public notice on 8th November 2019.

1. Copies of the letter of application for consent, the Environmental Statement and the additional information may be requested by letter to Siccar Point Energy E&P Limited, c/o Pinsent Masons LLP, 1 Park Row, Leeds, LS1 5AB, by e-mail to info@siccarpointenergy.co.uk or by telephone +44 (0)1224 678 008. Documents can be provided by post or e-mail. Documents may also be accessed via the internet at http://www.siccarpointenergy.co.uk/news.

2. Representations relating to the letter of application for consent, the Environmental Statement and the additional information may be made to the Secretary of State by 25th July 2020, by letter or e-mail to:

   Business Support Team
   Department for Business, Energy and Industrial Strategy
   Offshore Petroleum Regulator for Environment & Decommissioning
   AB1 Building
   Crimon Place
   Aberdeen, AB10 1BJ
   Email: BST@beis.gov.uk

SICCAR POINT ENERGY

Cambo Environmental Statement (D-4240-2019)

Additional Information Requested by BEIS under Regulation 10(2) of the Offshore EIA Regulations

OPRED Ref:	**4**	**ES Section:**	**Section 2 – Various pages – Option Selection**
OPRED Comment: **(01/02/2020)**		While the rationale for rejection of the various aspects of the development are well presented and clear there is limited, or no discussion of the positives associated with each option. Without this information a balanced conclusion on the acceptability of the proposals cannot be drawn. Please review this section to ensure both positive aspects and limitations/rationale for rejection for each development aspect are described throughout this section.	
Additional Information Provided by SPE:		*Refer to Attachment 1, 'Option Selection Summary', for commentary on positive aspects of the options considered but ultimately rejected in each case. In some cases, it is judged that the ES section as presented provides positives associated with each of the options. These are identified within Attachment 1.*	

OPRED Ref:	**5**	**ES Section:**	**Section 2.2.3.3 – Page 2-15 – Produced Water Management - Minimisation of Produced Water**
OPRED Comment: **(01/02/2020)**		Please expand upon the technical reasons for the limited scope to manage water production at Cambo e.g. provide more detail on why water shut-off is unlikely to be suitable and the level of impact upon production that inflow control devices are expected to have.	
Additional Information Provided by SPE:		*The Cambo producers are high angle/horizontal wells targeting clean, relatively thin (low tens of metres thick) homogeneous sands. The reservoir sections will be completed with sand control. Without suitable thick non-reservoir (e.g. shale) intervals and/or blank pipe within the lower completion, the options to mechanically shut-off water are limited and are likely to be quickly bypassed. The reservoir sands being targeted by the wells are relatively flat, in a low dip structure, and displacing injection water will quickly move to the producing section. Given the deepwater environment at Cambo, the cost of any well intervention will be high, making it is expensive to acquire well data such as production logs to support a decision to attempt water shut-off, and making it more difficult to justify speculative interventions. Evaluation of inflow control devices such as Autonomous Inflow Control Devices (AICDs) have been undertaken by Siccar Point Energy and one vendor indicated negligible benefit in terms of oil production. AICDs are currently incompatible with the favoured choice of sand control of alternate path open-hole gravel packing. Whilst offering some benefits in terms of reducing water, again, as for water shut-off, it is expected that water would quickly bypass any individual AICDs which are restricting water inflow. AICDs and other inflow control devices introduce an additional pressure loss, which would lower production rates and give rise to a loss of economic value in addition to their cost, of hundreds of thousands of pounds per well.*	

OPRED Ref:	**6**	**ES Section:**	**Section 2.2.3.3 – Page 2-16 – Reservoir Souring**
OPRED Comment: **(01/02/2020)**		Reference is made to modelling indicating an increase in magnitude of H_2S when comparing combined Produced Water Reinjection (PWRI)/seawater injection vs seawater only injection. Please expand upon this position i.e. present evidence to support this statement including modelling undertaken and clarify the level of risk associated with PWRI/seawater injection vs seawater only injection i.e. demonstrate the difference in level and timing of reservoir souring for combined PWRI/seawater injection vs seawater only injection.	
Additional Information Provided by SPE:		*Reservoir souring studies were undertaken by the specialist consultancy OilPlus, considering injection of a combined mix of produced water/seawater and seawater alone, performing sensitivities to various key parameters such as nutrient levels, reservoir temperature, well spacing, etc. Injection of produced water led to predictions of many orders of magnitude higher levels of H_2S. For otherwise common assumptions, the base case predictions give a maximum concentration of H_2S in gas of 1366 ppm for a mix of PWRI and seawater versus 69 ppm for seawater injection alone. Significant H_2S of tens of ppm in gas occurs within the first few years of production for both PWRI and seawater injection.*	

OPRED Ref:	**7**	**ES Section:**	**Section 2.2.3.3 – Page 2-16 – Reservoir Souring**
OPRED Comment: **(01/02/2020)**			**(ii)** It is stated that the proposed development is restricted to a low gas export H_2S specification for entry into the West of Shetland Pipeline System (WOSPS) due to the lack of available capacity in onshore H_2S removal/gas sweetening (later confirmed as 2kg H_2S/day). It is further stated that this would require offshore gas sweetening, presumably only in the case of PWRI but this is not stated. Section 2.2.3.4 states that reservoir souring will occur through the introduction of sulphate in seawater but a sulphate removal package (SRU) is proposed to reduce the level of sulphate introduced. Please expand upon the justifications for the decision to reject the various reservoir souring techniques described in the case of PWRI i.e. explain why membrane filtration is considered the only feasible and proven option, describing the positives and negatives of the other discounted options.
Additional Information Provided by SPE:			*To clarify, offshore gas sweetening is proposed to cater for H_2S removal for the seawater injection only case. Refer to Attachment 2 'Reservoir Souring Management Techniques' for commentary on reservoir souring management assessment.*
OPRED Comment: **(01/02/2020)**			**(iii)** The use of a SRU for produced water treatment has been ruled out for weight, footprint, capital costs and operating costs. Please clarify why a SRU is proposed for seawater treatment but not for PWRI.
Additional Information Provided by SPE:			*Studies undertaken by the Cambo partners and specialist consultancy OilPlus concluded that reduction in sulphate concentration of injected seawater (from an untreated sulphate concentration of 2,770 mg/l) would be effective in reducing the extent of Cambo reservoir souring. A further key benefit of sulphate removal from injected seawater is reduction in barite scaling risk, and so on this basis an SRU for seawater treatment is proposed.* *The sulphate concentration of Cambo produced water is low in comparison to seawater at circa 15 mg/l. An OilPlus assessment observed only marginal reduction in souring tendency at sulphate concentrations in injection water from 100mg/l to 40mg, and so reduction below this low level in produced water was not considered to be of benefit.* *In addition, of the range of treatment techniques for the removal/reduction of sulphate (including Multi-Stage Flash (MSF) distillation, Reverse Osmosis (RO), Electrodialysis Reversal (EDR), Nanofiltration (NF), Ion Exchange, Precipitation and Freeze Distillation), only NF was considered feasible and proven in offshore applications. NF employs membrane technology which, at the scale required to treat Cambo produced water rates, will add significant capital cost and weight/space requirements. The membranes are susceptible to high turnover/operating cost in produced water applications as a result of fouling by residual oils, waxes, solids etc. in the produced water, and as such significant pre-treatment would be required upstream of the membranes, adding further complexity, weight/space requirement and cost.*
OPRED Comment: **(01/02/2020)**			**(iv)** Please clarify to what extent the decision to utilise a Sevan unit over a ship-shaped FPSO has influenced this decision i.e. would a ship-shaped FPSO allow for the additional weight and footprint of a SRU to treat produced water?

Additional Information Provided by SPE:	*The choice of hull type has not influenced decisions with respect to sulphate removal from produced water. Whilst a conventional ship-shaped FPSO may in principle offer greater footprint and weight-bearing capability, there are other very significant issues behind the selection of the Sevan hull concept for Cambo. Amongst the most significant is the technical feasibility risk and very high cost to provide a large ship-shaped FPSO turret mooring and riser system suitable for the deep water, harsh environmental conditions at Cambo West of Shetland.*

OPRED Ref:	8	ES Section:	Section 2.2.5.4 – Page 2-23 – Main Power Generation
OPRED Comment: (01/02/2020)		**(i)** Onshore power from renewable sources has been rejected as an option. Please clarify what opportunities for pursuing this option have been considered including opportunities for partnerships with other operators in the area, both existing and proposed developments and explain why they have been discounted.	
Additional Information Provided by SPE:		*SPE have engaged with SSE with regards to the potential for onshore power supply from the Shetland Islands to Cambo from the proposed Viking wind farm development, and/or onshore power supply via cable from the UK mainland via Shetland through the proposed new HVDC interconnector. In terms of opportunities for partnerships with other operators, SPE are aware of BP (as operator of the Clair field) and their consideration of power from shore for the Clair South project. Further, as partners with Operators Equinor in the Rosebank development, SPE are familiar with plans to investigate the power from shore option in concept select (including engagement with BP).* *Short studies concluded that, whilst technically feasible, uncertainty over approval and timing to completion of these projects (estimated no earlier than 2024, with subsequent connection to Cambo no earlier than 2025) would present a significant risk to the Cambo project. In addition, the estimated cable and ancillary equipment cost (including Cambo onshore HVDC rectifier, offshore HVDC inverter) would be prohibitive, whether from Shetland or another onshore location. Costs are estimated at circa £200m for a 40MW power supply to Cambo. Some local offshore generation capacity would also need to be retained to provide assurance of power supply reliability.* *The relative timings of Rosebank and Clair South projects which could provide an opportunity for collaboration/cost sharing are also not compatible with the Cambo development timing. FID for both projects is envisaged in 2022. There were no existing developments identified that utilised onshore power from renewable sources and offered scope for collaboration.*	
Further OPRED Comment on (i): (16/04/2020)		Within the initial ES and in relation to the opportunities for onshore renewable sources of power for Cambo, SPE stated both BP and Equinor are considering power from shore in relation to the Clair South and Rosebank projects respectively which could provide an opportunity for collaboration/cost sharing. It was however stated that the timing of these projects (estimated no earlier than 2024, with subsequent connection to Cambo no earlier than 2025) was not compatible with the Cambo project and would present a significant risk to the project. The Department is now aware that SPE have pushed back some aspects of the Cambo project development and as such SPE are requested to review the potential for collaboration/cost sharing with other operators with a view to utilising onshore renewable power as part of the Cambo project. Please also confirm the revised Cambo project schedule including key decision gates.	
Further Information Provided by SPE:		*SPE and partners Shell have indeed deferred the planned sanction date for the Cambo project from the original target date of 3Q of 2020 as a direct result of the unprecedented worldwide macroeconomic events resulting from COVID-19. The revised target date is now the second half of 2021, in line with the licence extension granted by the OGA and stabilisation in market conditions such that a robust path to project delivery can be re-established.* *SPE have reconsidered the potential for collaboration/cost sharing with other Operators in terms of utilising onshore renewable power as part of the development. However, SPE has established that BP and Equinor are similarly reassessing project activity and projected capital expenditure in 2020 and 2021, and the timelines of their respective projects (SPE also notes that the BP Clair South project is to be suspended in June 2020). As a*	

	consequence, SPE believes that the respective project timelines remain incompatible with SPE's plans for the Cambo development, despite the sanction date deferral. *In addition, SPE have undertaken further discussions with SSE (transmission infrastructure) to further understand the schedule associated with providing the requisite onshore infrastructure to effectively provide a secure supply connection to Cambo via SSE's proposed Kergord HVDC substation (scheduled for 2024/2025 assuming sanction by end 2020). The additional onshore infrastructure timeframe is split into two phases, (1) the application, consultation and approvals phase and (2) the Engineering, Procurement and Construction (EPC) execute phase. The initial phase, inclusive of pre-application, conceptual design, scoping, application, statutory and non-statutory consultations, planning consultation and approval, has a 36 months cycle time. Post approvals and final investment decision, land purchase, engineering, procurement, construction, commissioning phases are approximately 36-48 months duration to provide a commissioned connection. The initial application, consultation and approvals process would delay Cambo's FID into 2024, 2 years after the recently revised licence extension, with first power available to Cambo into 2027 at the earliest. The onshore power connection infrastructure timeframe is not aligned with Cambo's development programme schedule and there is no way of knowing whether, in fact, the infrastructure project will even be sanctioned.* *SPE are currently targeting Decision Gate 3 (Sanction-Execute) at the end of 1Q 2021, with FID in early 2H 2021. On this basis, first oil is forecast in 2H 2025 (with some scope for acceleration dependent on market conditions).*
OPRED Comment: **(01/02/2020)**	**(ii)** Please clarify whether any existing onshore non-renewable power supplies have been considered and where these have been ruled out please expand upon the positive and negative aspects considered compared with non-renewable offshore power generation as currently proposed.
Additional Information Provided by SPE:	*Onshore non-renewable power supply from the Shetland Islands was considered, but currently there is insufficient electrical power generation capacity on the Shetland Islands to provide the required 40MW of power to the Cambo facilities.*
Further OPRED Comment on (i): **(16/04/2020)**	SPE state that there is currently insufficient electrical power generation capacity on the Shetland Islands to provide the 40MW of power required for Cambo. Please confirm what efforts have been made to determine whether any alterations to existing onshore non-renewable power plant(s) could achieve cost-effective solutions to onshore power provision e.g. has a cost benefit analysis been carried out in this regard.
Further Information Provided by SPE:	*SPE has not identified any credible routes to establishing a source of onshore, non-renewable power for export to Cambo. The environmental benefits of sourcing onshore, non-renewable power for export to Cambo are unclear. Not only would there be the additional economic burden of paying for power, when the FPSO has gas available to generate power, but power from shore would more than likely result in additional environmental impacts both onshore and offshore with the impact of additional infrastructure that would be required. Surplus gas from the Cambo FPSO will be exported to WOSPS so that flaring and associated environmental impacts are minimised (there is little economic gain from exporting gas to WOSPS).* *Furthermore, the indicative CAPEX delta to provide power from shore (established through SPE's assessment of power import from onshore renewable sources), requirements for an alternative source of energy for process heating (circa 24MW in addition to the 40MW process load) and uncertainty and risk in terms of CAPEX, OPEX and timeline were considered to be compounded by this option (including onshore brownfield modification risk).*

OPRED Ref:	**9**	**ES Section:**	**Section 2.2.5.4 – Page 2-23 – Main Power Generation**
OPRED Comment: **(01/02/2020)**		This section concludes DLE ready turbines have been selected. This section clarifies that only the package skid and enclosures will be designed to accommodate DLE turbines. It is unclear how these design features constitute DLE ready turbines since the turbines themselves require to be changed out. Please clarify.	
Additional Information Provided by SPE:		*Following further evaluation and engagement with power generation package vendors, SPE now propose to procure dual fuel units that are gas fuel DLE/liquid fuel LDI (Lean Direct Injection).* *The key issues relating to DLE option cost, performance and reliability on fuel gas have been addressed sufficiently to give confidence in this approach. Further, LDI is an advancement in design to allow more operational flexibility in terms of liquid fuel quality for offshore applications (one of the key issues identified with the traditional dual fuel DLE approach) and is a lower risk adaptation of dual fuel DLE vendor product. With the facility to import gas on Cambo, it is envisaged that the frequency of operation on liquid fuel will be limited, and so increased emissions in comparison to traditional dual fuel DLE will be limited.*	

OPRED Ref:	**10**	**ES Section:**	**Section 2.2.5.4 – Page 2-25 – Main Power Generation**
OPRED Comment: **(01/02/2020)**		**(i)** It is concluded that industry experience indicates DLE turbines may present reliability, operability and mechanical failure issues. Please expand on this statement and provide evidence of such issues including when and where they occurred and advise whether technology has improved since these issues were experienced. Please note the Department is aware that DLE turbines are currently in use on recently commissioned oil and gas production activities.	
Additional Information Provided by SPE:		*Following further evaluation and engagement with power generation package vendors, SPE now propose to procure dual fuel units that are gas fuel DLE/liquid fuel LDI (Lean Direct Injection).*	
OPRED Comment: **(01/02/2020)**		**(ii)** It is further stated that the mechanical and emissions performance of DLE turbines is dependent upon load. Please clarify how this is relevant to the proposed combustion plant operation on the FPSO.	
Additional Information Provided by SPE:		*Cambo power demand and therefore turbine load will vary between circa 70-93% (normal and peak/offloading conditions, based on total load split between 3 x 50% units). Operational DLE range is load dependent and variable for different suppliers, and DLE systems can experience issues when plant load means the turbines are switching in and out of DLE control. Issues can include combustor oscillations and downstream damage to the turbine and exhaust systems.* *Assessment has concluded that at forecast loads for Cambo (and with advances in turbine control), DLE performance on fuel gas can be achieved.*	

OPRED Ref:	**11**	**ES Section:**	**Section 2.2.5.6 – Page 2-26 – Produced Water Treatment**
OPRED Comment: **(01/02/2020)**		**(i)** It is stated that the produced water treatment system has been designed to treat 100% of anticipated produced water to a target residual dispersed oil in water specification of 15mg/l or less (monthly average). Please clarify what data has been used to determine the highest level of produced water, clarify that the system has been designed to treat this level of produced water to the specified standard and explain how the system will be designed with capacity for future Cambo development phase(s).	
Additional Information Provided by SPE:		*Specifications and datasheets for the FPSO produced water treatment package have been prepared based on the Cambo produced water physical property data obtained from the 204/10a-5 well. These specifications and datasheets have been reviewed by the proposed suppliers who have confirmed that they can guarantee a residual dispersed oil in water specification of 15 mg/l. Whilst is it possible that actual performance will be better, the proposed vendors are unable to guarantee a residual dispersed oil in water specification below 15 mg/l without a tertiary treatment stage.* *The design capacity of the produced water treatment package has been set at 80,000 bwpd based on Cambo subsurface simulation and production profiles. Future development phase(s) will be managed within this capacity by optimising the well stock and where necessary shutting-in high water cut wells.*	
Further OPRED Comment on (i): **(16/04/2020)**		The design capacity of the produced water treatment package has been confirmed as 80,000 bwpd and SPE have stated that future development phase(s) will be managed within this capacity by optimising the well stock and where necessary shutting-in high water cut wells. a) Please confirm that a maximum monthly average oil in water concentration of 15mg/l will be achieved if this maximum level of throughout were to be realised. b) In addition, SPE made a commitment within the commitments register for produced water discharges to comply with the OSPAR 30mg/l dispersed oil standard [monthly average] but will design produced water treatment to achieve a lower dispersed oil content of 15mg/l. Given that the likely limit to be applied via an OPPC permit will be 15mg/l in relation to the dispersed oil discharge within produced water please confirm that SPE commit to achieving, rather than targeting this concentration.	
Further Information Provided by SPE:		*(a) SPE can confirm that the produced water treatment package has been designed to achieve the stated oil in water concentration on a monthly average basis at the design capacity of 80,000 bwpd.* *(b) SPE respectfully propose that the current commitments register wording with regard to target dispersed oil in water discharge concentration is retained. The logic behind the current wording and proposal of a target value of 15mg/l (monthly average) can be summarised as follows. Whilst SPE have absolutely committed to the design, procurement and operation of a produced water package and separation system configuration for the Cambo FPSO that can expect to deliver produced water for overboard discharge at a residual dispersed oil in water concentration significantly better than the OSPAR performance standard, some uncertainties to achievement of this performance in operation do remain. These include; the effect of the severe Cambo metocean conditions on separation vessel motion/performance (with Cambo being the first deep water harsh environment development in the UKCS); other inherent uncertainties/complexities with respect to key treatment package feed properties for fluids like Cambo with propensity to form stable emulsions and which will contain residual sand/fines; separation performance changes over time with developing water cut and changes in application of production chemicals. The margin between target and commitment/current regulatory limit values provides some headroom to manage these uncertainties given the necessary reliance on overboard disposal of produced water to manage reservoir souring risk and maintain production/injection performance.*	

	SPE's operating strategy, to be developed in conjunction with the Installation Operator, will be firmly focussed on produced water quality and package performance from the onset of water production (in line with implementing and sustaining the BAT principle throughout the project life cycle), with measures being taken (for example, process condition and production chemistry optimisation) where required to address the uncertainties and optimise package performance. With operational experience gathered, SPE would seek to be in a position to lower the 30mg/l commitment towards the lower dispersed oil in water target.
Further OPRED Comment on (i): **(02/06/2020)**	With regard to the dispersed oil in water average monthly concentration it is noted that SPE refer to the 'OSPAR performance standard' and 'current regulatory limit [30mg/l] values' providing headroom to manage various uncertainties associated with the yet to be confirmed operational performance of the proposed produced water treatment package. SPE further state that with operational experience they would seek to be in a position to lower the 30mg/l commitment towards the lower dispersed oil in water target [15mg/l]. SPE are reminded that the widely implemented UKCS 30mg/l dispersed oil in water monthly average concentration is typically relevant to older installations with older technology and, crucially, it is not a fixed regulatory value. Cambo is a new installation and needs to achieve an oil in water concentration as low as is achievable via the application of BAT. With that in mind the OPPC (oil discharge permit) limit will be based upon BAT as stated within the ES and any oil discharge permit issued is likely to permit a maximum of 15mg/l dispersed oil in produced water. Please confirm that SPE understand this position.
Further Information Provided by SPE:	*SPE confirms it's understanding of this position.*
OPRED Comment: **(01/02/2020)**	**(ii)** Please clarify how it will be ensured that the produced water treatment system will achieve the target oil in water specification described above e.g. laboratory trials based on actual Cambo fluids
Additional Information Provided by SPE:	*The produced water treatment package is specified with a maximum residual dispersed oil in water specification of 15 mg/l. The proposed produced water treatment package suppliers (Alderley, Cameron, NOV, Techouse) are all reputable vendors who have confirmed that the following configuration will meet this requirement when considering Cambo fluids:* • *Primary Treatment - Desanding and Deoiling Hydrocyclones* • *Secondary Treatment - Conventional or Compact Flotation Unit (vendor dependent)* *In order to maximise the performance of the Flotation Unit it is also planned to inject deoiler and/or flocculant chemicals upstream of the unit. This will aid the coalescing of the oil droplets in the unit and improve performance. The chemical selection will be subject to laboratory review and confirmation in the field.*
OPRED Comment: **(01/02/2020)**	**(iii)** Reference is made to sand/fines production. Please clarify what level of sand is expected to be produced and how this has been determined.
Additional Information Provided by SPE:	*The Cambo sands are weak and sand control is required in the wells in order to limit sand production into the wellbore and solids transport to the subsea pipelines and surface facilities or sand fill of the wellbore, restricting or preventing production. The type of sand control is yet to be selected but will comprise a compliant depth filter (i.e. Open Hole Gravel Pack or Baker Hughes' GeoFORM®). The particle size distribution (PSD) of the Cambo sand has been measured by both sieve and laser diffraction techniques. This PSD in conjunction with industry standard criteria has been used to select the most appropriate sand control method. Sand retention testing has also been carried out on the mesh of premium screens which*

	indicated unacceptable levels of plugging and use of standalone screens has been rejected. Retention testing is now being carried out on the GeoFORM® filter media as part of the ongoing evaluation. Whether Open Hole Gravel Pack or GeoFORM® is selected, both systems provide a filter layer which is compliant with the wellbore. Whilst the sand control should limit sand production, levels of sand production are still expected, which have been estimated based on a plastic radius calculated from the mechanical properties of the formation, the in-situ stress and drawdown, giving a sand rate of up to between 2 and 7 lbs per 1000 bbls. These levels of sand production are consistent with analogue fields.
Further OPRED Comment on (iii): **(16/04/2020)**	Should the proposed sand control measures fail please confirm that the topsides sand removal facilities will be capable of coping with SPE's worst case sand production estimates, treating the sand to the required standard prior to discharge or by another means.
Further Information Provided by SPE:	*The FPSO topsides sand removal and treatment facilities are designed to cater only for the levels of sand predicted to be produced through the proposed downhole sand control measures described previously (which, by design, limit rather than completely prevent sand production to the vessel). At these levels, SPE can confirm that sand removed can be treated to the required standard prior to discharge/disposal.* *In the event of sand control failure, it is expected that (dependent on the nature of the failure) sand production would be managed to within the capabilities of the topsides facilities by cutting back production or shut-in of the well in question pending intervention.*
OPRED Comment: **(01/02/2020)**	**(iv)** The ES states that production will be restricted or shut in if produced water is out of specification and there is insufficient capacity to store water for later treatment. Please clarify what is meant by oil in water specification not being met i.e. does this relate to the monthly average concentration or the instantaneous maximum concentration?
Additional Information Provided by SPE:	*This is in relation to the ability to stay within the monthly average concentration.*
OPRED Comment: **(01/02/2020)**	**(v)** Please clarify under what circumstances production would be restricted and under what circumstances it would be shut in.
Additional Information Provided by SPE:	*During production it is possible that there may be certain process upsets or outages (e.g. slugging, loss of deoiler chemical injection, reduced hydrocyclone efficiency caused by blockages etc.) where it is clear that the monthly average oil in water specification will be jeopardised if production continues. An assessment will be made on a case-by-case basis to either restrict or shut-in production depending on the ability to remain within the monthly average concentration based on the forecast excursion duration.*
OPRED Comment: **(01/02/2020)**	**(vi)** It is noted that some deck space and weight capacity will be reserved for the addition of future (produced water treatment) equipment, which may include tertiary equipment. Please clarify whether the compact floatation unit currently proposed is regarded as tertiary treatment and under what circumstances would additional equipment be required.

Additional Information Provided by SPE:	*The compact flotation unit currently proposed is not regarded as tertiary treatment. The Produced Water Treatment equipment is classified according to the following:* • *Primary Treatment - Desanding and Deoiling Hydrocyclones* • *Secondary Treatment - Conventional or Compact Flotation Unit (vendor dependent)* *The above configuration has been confirmed by vendors as being capable of achieving a monthly average oil in water concentration of 15 mg/l. Tertiary treatment is only envisaged to be required if in future a more stringent monthly average oil in water concentration limit is imposed.*

OPRED Ref:	13	ES Section:	Section 2.2.5.10 – Page 2-31 – Fate of Produced Gas
OPRED Comment: (01/02/2020)	Following the decline of Cambo production it is stated that the import of fuel gas is particularly important. Please clarify how the availability of import gas and compatibility of this gas with the Cambo FPSO gas systems/combustion plant has been proven i.e. how has it been determined that the import gas specification will be suitable.		
Additional Information Provided by SPE:	*The specifications and datasheets provided to vendors for relevant fuel gas users include composition data for the required range of design cases (including fuel import). Essentially, however, fuel gas imported will be WOSPS pipeline specification gas, and will be routed to Cambo FPSO gas treatment to ensure quality and conditions (level of contaminants, water/hydrocarbon dewpoint, degree of superheat etc.) are as required for all users.*		
Further OPRED Comment: (16/04/2020)	Thank you for confirming that the imported fuel gas specification has been taken into account for the relevant fuel gas users on the Cambo FPSO. Please also confirm how it has been determined that imported West Of Shetland Pipeline System (WOSPS) fuel gas will be available at Cambo for the life of the field i.e. security of supply for Cambo.		
Further Information Provided by SPE:	*Security of supply of import gas was one of the key decision criteria in selecting the WOSPS system as the gas export/import route for Cambo. Specific uncertainty was identified with respect to commercial arrangements for the continuation of sweetening facility operations due to the expiry of the Sullom Voe Terminal (SVT) agreements and the SVT Land Lease. However, it was noted that other long-life fields including the Clair Ridge and Quad204 developments are reliant upon WOSPS and the sweetening facility, and some are expected to continue to require a gas export route or import gas source beyond 2045. In addition, other prospective West of Shetland developments including Equinor Rosebank and Hurricane Lancaster have identified WOSPS as a prospective gas export route. As such there is confidence that the necessary agreements will be extended or replaced to enable continued service, and that fuel import for Cambo can be secured over field life.*		

OPRED Ref:	**15**	**ES Section:**	**Section 2.2.5.12 – Page 2-38 – Export Pipeline Protection**
OPRED Comment: **(01/02/2020)**		It is stated that the pipeline may be deployed using tracked jetting machines and that where the trenching may encounter harder soils and fails to meet the required trench depth some rock deposits will be required. From survey information available to date please clarify if jetting is considered a viable option and whether there are any indications that it may encounter some harder soils along the proposed route.	
Additional Information Provided by SPE:		*Available survey information available suggests that jetting may be a viable option for the majority of the route although some areas may not be suitable and therefore require rockdump remediation. At tender stage, the installation contractors will be required to carry out a full trenching assessment, specific to the machines they have available in house (or as a hire from third parties) and make an appropriate recommendation.*	

OPRED Ref:	**18**	**ES Section:**	**Section 3.5 – Page 3-6 – Drilling Operations**
OPRED Comment: **(01/02/2020)**	It is stated that further detailed assessment is required to determine if CAN-Ductors can be used. Please clarify what this assessment will entail and when it will be undertaken.		
Additional Information Provided by SPE:	*During 2019 site survey operations, geotechnical data was recorded at the drill centres to allow proper assessment of the CAN-Ductor installation environment. This data was supplied to Neodrill (owners of the CAN technology) who sub-contracted NGI to perform shallow soils analysis with an eye to validating and potentially optimising the CAN-Ductor design to make it Cambo field-specific. Results of NGI's study were fed back into the larger Neodrill design engineering and optimisation piece. Results of the study confirmed that seabed conditions at the 2018 5Y well (P2) are typical of the field and verified suitability of the CAN-Ductor technology.*		

OPRED Ref:	**23**	**ES Section:**	**Section 3.7.1 – Page 3-19 – FPSO concept**
OPRED Comment: **(01/02/2020)**		Please clarify if the FPSO will be equipped with self-sealing quick release riser mechanisms to limit the release of oil/chemical in the event that mooring is compromised for example in severe weather.	
Additional Information Provided by SPE:		*The mooring and riser systems are designed to withstand all anticipated environmental conditions for the life of field, including 1000-year wind and current events as per industry standards. No self-sealing, quick release mechanisms are required.*	
Further OPRED Comment: **(16/04/2020)**		Thank you for confirming there are no self-sealing, quick release mechanisms planned for the risers, with the subsea infrastructure being designed to withstand all anticipated environmental conditions for the life of the field. Please note, particularly in the absence of such quick release mechanisms, the Department considers any future Cambo adverse weather policy to be critical in mitigating the risk posed by adverse weather conditions.	
Further Information Provided by SPE:		*Noted with thanks.*	

OPRED Ref:	31	ES Section:	3.7.6 – Page 3-26 – Gas Processing – Gas Treatment
OPRED Comment: (01/02/2020)	**(i)** The first paragraph describes H_2S removal via absorption beds to meet the 2kg/day maximum H_2S WOSPS entry spec for Cambo. Please clarify the anticipated frequency of media change out in the absorption beds and demonstrate how this unit will be available at all times of production to ensure flaring of gas is avoided.		
Additional Information Provided by SPE:	*The solid adsorbent beds have been specified with a media change out frequency of once per year based on an H_2S loading of 20ppmv (1st Stage Separator vapour outlet). This represents a 100% design margin over the peak H_2S levels predicted by reservoir souring studies.* *The adsorption beds are specified in a lead-lag configuration. An H_2S analyser will be provided between the two beds which will detect when the lead bed media is spent. At this point the lead bed will be isolated and the media changed out. The lag bed will continue to operate during this period and will then be designated the lead bed. This alternation of lead-lag bed will continue and ensure that the facility can operate uninterrupted during media changeout without any flaring of gas or impact on export specification.*		
OPRED Comment: (01/02/2020)	**(ii)** What course of action will be taken in the event that the WOSPS H_2S criteria cannot be met?		
Additional Information Provided by SPE:	*The selection of solid adsorption bed technology will ensure that the WOSPS H_2S criteria can always be met since it operates with 100% efficiency. The use of the beds in a lead-lag configuration also provides a further guarantee that the specification will be met as the lag bed will continue to remove all H_2S, even as the lead bed approaches the end of its operating life.* *The more likely risk is that higher H_2S levels are encountered than expected and media changeout is more frequent. In the event that higher H_2S levels are encountered SPE intend to employ H_2S scavenging to ensure that the H_2S loading of the solid adsorbent bed remains at 20 ppmv. This will ensure the solid adsorbent beds continue to operate with the same changeout frequency and that they carry out the final H_2S removal to achieve the specification for entry to WOSPS.* *Whilst Cambo is targeting a gas export spec of sub 2.3 ppmv H_2S into WOSPS, it should be noted that the technical specification limit for H_2S in WOSPS is 1000ppmv. Cambo is close to finalising commercial agreements providing access to H_2S removal capacity at the onshore Sweetening Facilities located at Sullom Voe Terminal – these agreements will allow Cambo gas to be sweetened on a reasonable endeavours basis should the H_2S levels in Cambo's export gas stream exceed 2.3ppmv. Over recent years the Sweetening Facilities at Sullom Voe Terminal have tended to operate well below their capacity limitations so Cambo has confidence that Sweetening Capacity will be available if required.*		
Further OPRED Comment on (ii): (16/04/2020)	It is noted that SPE are close to finalising commercial agreements providing access to H2S removal capacity at the onshore sweetening facilities at Sullom Voe Terminal. Please confirm the current status of these commercial agreements and if agreements are not yet in place please confirm when they are anticipated to be concluded.		
Further Information Provided by SPE:	*Negotiations with SVT Sweetening Facility operator BP have progressed well with final Execution Versions of the agreements expected to be agreed within May. Signing of the agreements is expected to be completed in June.*		

OPRED Comment: **(01/02/2020)**	**(iii)** Please confirm the limitations of the absorption bed technology that would preclude them being considered suitable to reduce the H_2S concentration of produced gas in the event PWRI was used.
Additional Information Provided by SPE:	*Absorption bed technology, whilst 100% efficient, is only suitable for relatively low H_2S loadings as the volume of media required is directly proportional to the H_2S loading and the frequency of media changeout. At high H_2S loadings the volume of media required becomes impractical (space and weight) unless a very frequent media changeout is adopted. Solid adsorbent beds are therefore only typically used for polishing applications where the outlet specification is very low. As an example, the solid adsorbent beds proposed for Cambo are specified based on 60 MMscfd gas rate with 20ppm H_2S loading and a changeout frequency of 1 year. This results in the following vessel sizes and weights:* • *34m^3 bed volume* • *Bed dimension 2.8m (ID) x 6.8m (T/T)* • *Skid dimensions: 7.4m x 6m x 9.4m* • *Operating Weight per bed 137 tonne* *With re-injection of Produced Water the H_2S loadings are expected to increase to peak levels of up to 1366 ppm. This level of H_2S would make the solid bed size impractical unless a very frequent media changeout is adopted which is not considered acceptable from an Operations perspective.*

OPRED Ref:	**63**	**ES Section:**	**Section 8.7 – Page 8-8 – Mitigation Measures (atmospheric impacts)**
OPRED Comment: **(01/02/2020)**		It is stated that Cambo will not have routine flaring or venting of gas associated with production unless this is demonstrated to be impractical by a technical, environmental, safety and commercial evaluation. This statement introduces doubt over the earlier information presented within the ES that states there will be no routine gas flaring. If routine flaring of gas is a realistic possibility, then this must be assessed within the ES. Please clarify.	
Additional Information Provided by SPE:		*The Cambo FPSO is designed to have no routine flaring or venting of gas during normal steady state production. The Cargo tanks are blanketed with fuel gas which will be recovered to the process via the Vapour Recovery Blower. This unit will also be used to recover all off-gas associated with the various process packages (e.g. CFU flotation gas, compressor seal gas, TEG stripping gas).*	

OPRED Ref:	**64**	**ES Section:**	**Section 8.7 – Page 8-8 – Mitigation Measures (atmospheric impacts)**
OPRED Comment: **(01/02/2020)**		It is stated that Dry Low NOx technology will be considered for combustion plant. Section 2.2.5.4 states that DLE turbines have not been selected and DLE technology will be kept under review. Please clarify the implications of this for Cambo i.e. how will technology be kept under review and at what point(s) will re-assessment of DLE suitability be made. Please clarify whether the change out of turbines is likely to be economically viable.	
Additional Information Provided by SPE:		*Following further evaluation and engagement with power generation package vendors, SPE now propose to procure dual fuel units that are gas fuel DLE/liquid fuel LDI (Lean Direct Injection). Please refer also to the response to Comment 9.*	

OPRED Ref:	**67**	**ES Section:**	**Section 10.1 – Page 10-1 – Produced Water Discharge - Reservoir souring**
OPRED Comment: **(01/02/2020)**		The Department understands that reservoir souring is likely to occur through either produced water re-injection (PWRI) or seawater injection, albeit at a faster rate in the case of PWRI due to the presence of a high content of volatile fatty acids (VFA). Further to comment 7 please clarify this understanding is correct and provide detailed evidence to support this position e.g. explain why the low temperature of the reservoir was considered to make the reservoir susceptible to Sulphate Reducing Bacteria (SRB), the difference in timeframe for souring between PWRI/seawater and seawater only injection and any modelling undertaken. Please clarify how it was determined that there is a high level of VFA such that this would encourage the growth of SRB. Please clarify what control measures are available for VFA elimination/reduction and where relevant why SPE consider these measures are not suitable for Cambo.	
Additional Information Provided by SPE:		*There is a greater concentration of nutrients for the SRB with produced water re-injection, including VFAs and other carbon sources. SRB presence and activity is mainly controlled by temperature, diminishing with increasing temperatures and being virtually inactive above 85 degrees centigrade. The Cambo reservoir temperature is relatively cool, about 61 degrees centigrade. Also refer to the response to item 6 above. VFA levels were measured in formation water samples taken whilst logging well 204/10a-5 in 2018. There is variance in the measured VFA concentrations between the three samples analysed and a souring prediction sensitivity was also performed for a higher VFA concentrations. For seawater injection, the higher VFA increases the maximum level of H_2S from the base case of 69 ppm to 197 ppm in gas.* *Refer to Attachment 3 for clarification on VFA elimination/reduction considerations for Cambo.*	

OPRED Ref:	68	ES Section:	Section 10.1 – Page 10-1 – Produced Water Discharge - Reservoir injectivity
OPRED Comment: **(01/02/2020)**	**(i)** This section states it is 'preferred' that only filtered, treated seawater is injected to reduce the risk of near well bore fouling and poor operability of PWRI systems. Please clarify why produced water cannot be filtered and treated to the same or a similar standard as seawater.		
Additional Information Provided by SPE:	*It is technically possible to filter and treat produced water to remove residual produced solids and dispersed oil in order to mitigate against the risks identified. However, the additional treatment package weight and layout requirements plus higher capital and operating costs to achieve and maintain the same or a similar standard to treated seawater (in terms of residual oil, SRB nutrient introduction, low solids loading and particulate size) are significant. Layout is a particular challenge for the FPSO.* *Note that depending on treatment type selection, filtration and treatment to manage fouling and operability aspects may not necessarily address potential souring risk as a consequence of produced water reinjection.*		
OPRED Comment: **(01/02/2020)**	**(ii)** Please quantify the risk of impacting reservoir injectivity in the case of PWRI vs seawater injection.		
Additional Information Provided by SPE:	*The presence of solids and oil in injection water will have an adverse impact on well injectivity from plugging, as commonly observed in oil fields. This effect has been confirmed by core flooding tests performing on Cambo core material, injecting water with a solids loading of of 30 mg/l and a range of particle sizes (7.5 mg/l of each of 3, 5, 10 and 25 microns) and in some tests with the addition of 30 ppm oil droplets. In all cases there was a loss of injectivity. The planned sand control should contain larger sand particles but allow production of fines, in order to prevent plugging and loss of productivity. As seen in other fields, these finer particles are expected to carry through the separators and be re-injected with PWRI. Fine filtered sea water will be delivered to the wells with a much lower solids loadings of only very small particles of less than 5 microns. The coreflood tests indicated a loss of injectivity of 69 to 78% over short durations of hours for the above solids loading. This permeability impairment would be expected to increase further over time and the LR consultancy noted the likelihood of longer term impairment in excess of 95%. Coreflood tests with smaller particles of < 5 microns gave reduced impairment of only 23 to 46%.*		

OPRED Ref:	**75**	**ES Section:**	**Section 13.4.3 – Page 13-8 – Oil Spill Modelling**
OPRED Comment: **(01/02/2020)**		The uncontrolled well blow out modelling has been undertaken utilising flow data for a well P4 which is no longer included in the current well plan but is considered representative of the actual wells to be drilled. To support this position please clarify the flow rate of the highest flow well in the current well plan.	
Additional Information Provided by SPE:		*The flow rates of the highest flow well in the current well plan are:* • *Day 0 to 5: 5,239 m^3* • *Day 6 to 10: 3,806 m^3* • *Day 11 to 20: 3,356 m^3* • *Day 21 to 30: 3,117 m^3* *Oil Spill Modelling using these flow rates has been undertaken. Section 13 - Accidental Events of the Cambo ES has been updated accordingly (see attached updated ES Section 13).*	

OPRED Ref:	**77**	**ES Section:**	**Table 13.1 – Page 13-9 – Well Blow-out Modelling Parameters**
OPRED Comment: **(01/02/2020)**	Please clarify whether the current regime in the area has been taken into account for modelling purposes i.e. direction of water flow at various depths. If a vertical profile model of the release has been undertaken, please provide this.		
Additional Information Provided by SPE:	*Yes, SPE confirms that the OSCAR model takes account of different current speed and direction throughout the water column. A vertical profile model of the release was undertaken and has been attached for reference. The vertical plume modelling shows that the oil plume is expected to rise up through the water column to the sea surface in approximately 2.5 hours, whereas the gas plume does not reach the surface and is absorbed into the water column. As the small oil droplets encounter the thermocline at ~400 m below sea surface the rise speed slows and some of the smaller droplets are halted. Although not shown in the model, it is most likely that any potential sub-surface oil plume would get trapped at this depth. At this depth, any trapped oil is likely to be driven by the Faroe-Shetland slope current, that generally flows towards the northeast (towards Norway) all year around.*		

OPRED Ref:	80	ES Section:	Section 13.6.1 – Page 13-27 – Preventative Measures
OPRED Comment: (01/02/2020)		**(i)** This section states that bunkering from supply vessels and offtake of crude oil via shuttle tanker will only take place during hours of good visibility which implies daylight hours. Given the crude package sizes involved the offtake of crude is considered unlikely to occur only during daylight hours. Please clarify.	
Additional Information Provided by SPE:		*Bunkering from Supply vessels and offloading to shuttle tankers will also take place during the hours of darkness. Management of marine operations during periods of low visibility (including fog) including assessment of risk will be subject to the controls detailed in the Marine Operations manual which has yet to be developed for Cambo FPSO.* *Specifically, for offtake operations, initial connection operations for crude offtake would be limited to connection and planned disconnection during daylight hours with offloading within the prescribed weather limitation continuing throughout the night (plan is 24hour operation for full parcel offload from tanker approach to depart). As experience of the local conditions and equipment is gained this will be reviewed to more of a risked based approach.*	
OPRED Comment: (01/02/2020)		**(ii)** Please advise if SPE intend to utilise infrared camera(s) as a further mitigation measure to observe bunkering and/or offtake of crude and allow an early warning of oil on the sea surface. Please note that the Department is aware of this technology already being employed on the UKCS.	
Additional Information Provided by SPE:		*The use of Infrared cameras is not currently being considered by SPE for bunkering and/or offtake of crude. However, this does not preclude any decision that the operator may take based on ALARP rational of the risk reduction.*	
OPRED Comment: (01/02/2020)		**(iii)** This section states that all hoses used for bunkering/offloading will be visually inspected and their connections tested prior to every loading (and presumably offloading) operation. Please clarify how the connections will be tested and whether it will be possible to inspect the entire circumference of the hoses.	
Additional Information Provided by SPE:		*Normally, the hose is visually checked as it is spooled off the reel during connection to the Tanker for any obvious damage. This is normally part of the Deck Checklist and will be similar for Bunkering operations. There are different systems supplied by vendors with regard to leak testing. As Hose Vendor selection for Cambo has not yet been finalised, the hose leak detection system for Cambo has yet to be confirmed. A yearly pressure test is also usually completed by the Hose Vendor but that is part of Planned Maintenance routines rather than routine marine operations.*	
OPRED Comment: (01/02/2020)		**(iv)** Please clarify what if any leak detection methods will be employed and what the anticipated change-out frequency of the crude offtake hose will be.	
Additional Information Provided by SPE:		*The normal practice of following operational procedure and pump ramp up plus validation by difference will be employed for Cambo. No specific additional equipment is planned.*	

Attachment 1 – Option Selection Summary

Option				Rejected Sub-Option	Positive Aspects
2.2.1	**Field Development Concept**			Full field stand-alone development	Economy of scale - potential overall capital expenditure efficiency improvement over phased development.
				Hub development	Infrastructure enabler to unlock development of other discoveries and prospects.
				Full stream tie-back to existing host	Low capital expenditure and schedule opportunities. Inherent safe design. Efficient use of existing infrastructure; reduced environmental footprint.
				Long range tie-back to shallow water platform	Technical risk associated with floating system in harsh, deep water environment removed.
				Standalone early production system	Lowest cost exposure in event of poor reservoir outcome. Schedule opportunity through redeployment of existing assets with modest conversion scope.
2.2.2	**Drilling/Wells**				
	2.2.2.1	*MODU Type*		DP drillship	Favourable mobility, transit speed, deck load capacity.
	2.2.2.2	*Well Type (Production)*		Low angle	Low complexity, reduced drilling costs
				Multilateral	Production enabled from multiple reservoir sections within the same well; well count and drilling cost reduction opportunity.
		Well Type (Injection)		Low angle	Lower complexity, reduced drilling costs
				Commingled	Well count and drilling cost reduction opportunity.
	2.2.2.3	*Well Construction*		Sequential drilling	None identified.
	2.2.2.4	*Drill Fluids and Cutting Disposal*		Low toxicity oil-based mud (LTOBM) and skip and ship to shore or offshore clean-up/disposal to sea.	None identified.
2.2.3	**Reservoir Management**				
	2.2.3.1	*Depletion Strategy*		Natural depletion	None identified.
				Gas injection	Potentially lower capital expenditure. Reduced environmental impact if not exporting via new pipeline infrastructure.
				Polymer Waterflood-type EOR	Potential increase in oil recovery.
	2.2.3.2	*Artificial Lift Strategy*		Natural flow	Simple well design. Reduced facilities complexity and cost.
				Downhole pumps	Higher production rate potential per well.
				Seafloor multiphase pumps	Reduced backpressure on wells; improved production opportunity. Improved flow assurance potential. Capital expenditure reduction opportunity through simplified SURF scope.

Option			Rejected Sub-Option	Positive Aspects
			Seafloor processing/pumps	Reduced backpressure on wells; improved production opportunity. Improved flow assurance potential. Capital expenditure reduction opportunity through simplified Subsea Umbilical Riser and Flowline (SURF) scope.
	2.2.3.3	*Produced Water Management*	Substantial discussion of options and Strengths, Weakness, Opportunities and Threats (SWOT) considered to have been provided in ES as presented.	
	2.2.3.4	*Reservoir Souring Management*	Substantial discussion of options and SWOT considered to have been provided in ES as presented.	
2.2.4	**Host Facilities**		TLP	Potential dry-tree solution. Favourable motion characteristics in harsh environment.
			SPAR	Potential dry-tree solution. Favourable motion characteristics in harsh environment.
			Semi-submersible	Potential improvement in safety gradient - cargo inventory not stored on facility.
2.2.5	**Facilities Design**			
	2.2.5.1	*Subsea Infrastructure*	Individual well tie-backs	None identified.
			Subsea template manifolds	No hydrate and other flow assurance issues associated with well jumper management. Fewer leak paths and smaller subsea installation scope.
	2.2.5.2	*Riser Type Selection*	Steel catenary	None identified.
	2.2.5.3	*FPSO Hull Type*	Ship-shaped	Potentially greater equipment footprint and weight capacity. Potentially wider range of contractors capable of delivery of ship-shaped units.
	2.2.5.4	*Main Power Generation*		
		Primary Power Source	Power from shore	Reduced requirement for offshore combustion equipment.
			Offshore power import	Reduced requirement for offshore combustion equipment.
		Turbine Fuel Supply	Imported liquid fuel	None identified.
		Turbine Configuration	No installed spare	None identified.
		Turbine Emissions Control	DLE installed	Reduced NOx and CO emissions.
	2.2.5.5	*Main Driver Selection*	Gas turbine drives	None identified.
	2.2.5.6	*Produced Water Treatment*	Substantial discussion of options and SWOT considered to have been provided in ES as presented.	
	2.2.5.7	*Flaring and Venting*	Closed flare; full flare gas recovery	Allows use of alternatives to permanently lit pilot ignition/reduced emissions. Reduced/eliminated purge gas requirements/emissions if purging with produced gas.

Option			Rejected Sub-Option	Positive Aspects
	2.2.5.8	*Cargo Storage Tank Blanketing*	Inert gas generation	Lower complexity; inherently safe.
	2.2.5.9	*Oil Export*	Export pipeline to shore	Reduced environmental risk - no offshore transfer of product to shuttle tanker.
			Export pipeline to 3rd party offshore	Reduced environmental risk - no offshore transfer of product to shuttle tanker. Reduced environmental footprint compared to pipeline to shore option.
	2.2.5.10	*Fate of Produced Gas*	Offshore sale to 3rd party	Reduced capital expenditure opportunity.
			Gas to products	None identified.
			Gas to power	None identified.
			Gas reinjection	Reduced capital expenditure in comparison to export pipeline solution.
			Operational flaring	Lower complexity and cost.
	2.2.5.11	*Gas Export Route Selection*	Substantial discussion of options and SWOT considered to have been provided in ES as presented.	
	2.2.5.12	*Gas Export Pipeline Protection*	Mechanical trenching/backfilling	This method works very well in stiffer soils giving good depth of lowering and the backfill process usually results in very good depth of cover which is particularly useful if upheaval buckling is a concern. Good backfill can result in a much lower remedial rock dumping requirement where there is a need to mitigate the potential for upheaval buckling of the pipeline e.g. for HP/HT systems.
			Jetting and/or;	This method is well suited to softer soils, particularly where the on-bottom weight of the much heavier ploughs used in mechanical trenching, cannot be supported. Often (though not always) jetting is matched with natural backfill, saving a run down the pipeline with a separate tool. Jet trenching does not involve any contact with the product, so is particularly suited to un-armoured cables/umbilicals or fibre optic lines. The deployed systems are smaller than mechanical ploughs, requiring smaller handling systems and potentially increased operational sea-states for launch and recovery.
			Rock dumping.	Provides very reliable protection to seabed infrastructure which is largely independent of the soil conditions. Can be very accurately placed on the seabed using fall pipe techniques even in very deep water.

Attachment 2 – Reservoir Souring Management Techniques

OPRED Comment 7(ii) - Reservoir Souring Management Techniques - PWRI Case		
Management Technique	**Positives**	**Negatives**
Biocide Dosing into Injection Water	Common first treatment strategy for microbial control in injection water.	Not fully effective for PWRI due to the organic content of produced water - often consumed readily. Use generally limited to cleaner seawater injection systems.
Free Radical Generator (FRG) Dosing	Highly effective biocide - promising emerging technique.	Relatively novel and not fully proven/adopted by industry.
Nitrate Dosing into Injection Water	Established SRB activity can be controlled by the injection of nitrate. Some evidence of effectiveness of technique e.g. Schiehallion.	High carbon availability in the injection and formation water increases the degree of nitrate dosing required, with resulting impact on OPEX. Not expected to be effective at Cambo reservoir temperature of 61oC.
Injection Water Sulphate Removal	Low sulphate injection water reduces barite scaling risk.	Sulphate removal reduces the concentration of sulphate in the injection water but does not eliminate it completely - sulphate removal processes are still able to reduce low amounts of sulphate injected to generate some sulphide in the presence of nutrients. Cambo produced water already low in sulphate, and so would provide little benefit.
		Sulphate removal systems in upstream offshore oil and gas applications generally utilise membrane nanofiltration - required pre-treatment very challenging with produced water reinjection systems, requiring significant filtration with potential for high membrane turnover due to fouling.
Injection Water Nutrient Removal	Refer to response to Comment 67 below.	

Attachment 3 – Volatile Fatty Acid (VFA) Reduction/Elimination Measures

OPRED Comment 67 - Volatile Fatty Acid (VFA) Reduction/Elimination Measures		
The table below summarises considerations and options for treatment of Cambo produced water where the primary objective is to reduce or remove VFA, the main source of nutrients for SRB activity/reservoir souring through PWRI on Cambo. Other secondary nutrients (extra carbon sources, biodegraded crude oil, nitrogen and phosphorus) are explicitly considered, although the techniques may in some cases also remove these components.		
Produced water treatments with different primary objectives (e.g. deoiling for removal of free and dispersed oil, disinfection for removal of bacteria, demineralisation for removal of dissolved salts, scaling agents etc.) are not included.		
Management Technique	**Positives**	**Negatives**
Precipitation		Solid waste generated. No known applications in offshore produced water treatment.
Multi-stage Flash Distillation		High energy demand and capital costs. No known applications in offshore produced water treatment.
Membrane Separation	Common technique for water purification. Relatively compact technology for offshore applications where weight / space are constrained.	No evidence found of application or effectiveness of nanofiltration for removal of highly soluble, low MW VFA in upstream offshore environment. Not proven for complex high-volume flow waste water streams. Significant pre-treatment requirements to prevent fouling/high turnover of required nanofiltration membranes.
Reverse Osmosis (RO)	Common technique for water purification. Can remove almost all contaminants.	No evidence found of application or effectiveness of RO for removal of VFA from produced water in upstream offshore environment. High pressure/energy requirements. Only trace amounts of contaminants can foul RO membranes.
Electrodialysis		Difficult process to scale up. Energy intensive. Prone to fouling. No known applications in offshore produced water treatment.
Ion Exchange		High resin costs and energy demand for resin regeneration. Low adsorption capacity.
Adsorption	Well established technique for produced water treatment.	High retention time/low capacity, high adsorbent costs, energy demand for adsorbent regeneration.
Oxidation		High energy inputs for ozone system; oil may foul catalyst; may produce sludge and toxic residues; requires some pre-treatment of produced water stream.
Biological		Not suitable for offshore application - large, heavy process with long residence times.
Solvent Extraction		No known applications in offshore produced water treatment at scale required for Cambo.
Macro Porous Polymer Extraction (MPPE)	Effective technique for BTEX (Benzene, Toluene, Ethylbenzene and Xylene) and polycyclic aromatics (PAHs etc.).	Not effective for organic acids/VFA separation.

SICCAR POINT ENERGY

Cambo Environmental Statement (D/4240/2019)

Section 13 - Accidental Events

13 ACCIDENTAL EVENTS

As well as assessing operational processes, the Environmental Impact Assessment (EIA) process also examines potential accidental events that may result in impacts upon the environment and for which mitigation measures may be implemented. The following issues and concerns were raised during the Environmental Issues Identification (ENVID) workshop and informal consultation and are considered in this section on the potential impacts from accidental events that could occur during operations at the proposed Cambo Field Development.

- Impacts on marine environment, the coastal environment and other users of the sea by a large spill of hydrocarbons to sea;
- Impacts on seabed communities as a result of the loss of the Floating Production, Storage and Offloading Vessel (FPSO), installation vessels, support vessels, the Mobile Operated Drilling Unit (MODU) or a helicopter.

The remainder of this Section describes the potential impacts of hydrocarbon spills (Sections 13.1 to 113.6) and from the loss of the FPSO, installations vessels, support vessels, the MODU or a helicopter (Section 13.7).

13.1 Sources of Hydrocarbon Spill

The risk of an accidental hydrocarbon spillage to sea is often one of the main environmental concerns associated with oil-industry activities. Spilled oil at sea can have a number of environmental and economic impacts, the most conspicuous of which are on seabirds and coastal areas. The actual impacts depend on many factors, including the volume and type of hydrocarbon spilled, the sea and weather conditions at the time of the spill, and the oil spill response.

The following events associated with the proposed Development have been identified as having the potential to cause an oil spill:

- Uncontrolled well blow-out;
- Loss of the FPSO inventory;
- A fuel oil spillage from an installation vessel, support and supply vessel or the MODU;
- An oil spillage when carrying out offloading operations to shuttle tanker;
- Loss of inventory of an infield flowline or riser.

The Cambo Field will produce crude oil with a density 902 kg/m^3 to 916 kg/m^3. A crude oil spill from either a well blow-out or a catastrophic failure of the FPSO storage tanks have been identified as the two worst-case oil spill scenarios, that could potentially result in a Major Environmental Incident (MEI).

13.1.1 Potential Crude Oil Spillages

Uncontrolled Well Blow-out

During drilling operations, a well blow-out would represent the largest potential source of a large hydrocarbon spill. For a blow-out to occur, the primary well control element, the hydrostatic pressure exerted by the drilling mud, would have to be overcome by the inflowing hydrocarbons. The secondary well control measure, the blow-out preventer (BOP), would also have to fail in closing off the well. The actual flow rate and duration of any such event, and hence the severity of the incident, are dependent upon the pressure and geology of the well, which vary with each well.

The flow rate encountered during an uncontrolled blow-out event may be very different from that expected during production, as there may be no equipment or other measures in place to restrict the flow. To model the potential worst-case blow-out scenario, it was assumed that there would be no physical restriction to the flow inside the well, such as drill string or tubing obstructing the wellbore, chemical build-up coating in the wellbore, a disconnected riser, or damaged wellhead and well control equipment on top of the well.

13.1.2 Potential Diesel (Fuel Oil) Spillages

Diesel will be the main fuel used for power generation during the proposed drilling operations and will be the largest volume of hydrocarbons stored on the MODU during the drilling operations. Similarly, the FPSO will have diesel storage capacity to run its diesel consumers. The diesel will be split between multiple fuel oil bunker tanks. The worst-case diesel spill scenario is considered to be the complete loss of the diesel inventory from all of the fuel tanks.

Smaller diesel spills can result from equipment failures, such as the rupture of pipes or open valves. As explained in Section 13.2.1, small spills most frequently occur during bunkering operations and are generally caused by hose failures. Diesel will be supplied from a supply vessel to the FPSO/MODU on regular intervals, via a flexible hose. As the hose is suspended between the two vessels, there is the potential for a direct diesel release to sea, if the hose or any of its connections are damaged during the bunkering operations.

13.1.3 Other Potential Sources of Oil

Lubricating and hydraulic oils are stored separately in tanks or sealed drums. Storage tanks for lubricating oil range in size, but each will normally contain a maximum of 15 m^3, while hydraulic oils are stored in much smaller 1 m^3 tanks. Additional oils may be transported and stored in sealed 0.025 m^3 or 0.21 m^3 drums or 1 m^3 tote tanks, all of which will be stored in dedicated, bunded storage areas, with oil spill kits located nearby. Up to approximately 12 m^3 of aviation fuel, contained in 2.7 m^3 or 4.0 m^3 helifuel tanks, will be held in a bunded area.

Waste oil will be generated on the FPSO and the MODU from a variety of sources, including waste engine, gear and hydraulic oil. These waste oils will be held in designated storage tanks and their volumes kept to minimum before being transferred to shore on regular intervals. Therefore, the possibility of a spillage from any of these sources is very small.

The amounts of lubricating, hydraulic and waste oil stored onboard the FPSO and the MODU will be very small in comparison to the main fuel supply. The probability of any spillages from any of these sources is considered to be minimal, as the containers are relatively small, sealed and stored in bunded areas. Therefore, the risk to the environment from these oils is regarded as negligible and is not considered further within this section.

13.2 Likelihood of a Hydrocarbon Spill from the MODU

Historical data, covering the period between January 1990 and April 2019, indicate that the possibility of a large hydrocarbon spill from a MODU operating on the UKCS is very low. As shown in Figure 13.1, most spillages from MODUs are caused by other/unknown (316) and hydraulic/lube (313). However, these are typically quite small spillages. Looking at the overall volume of hydrocarbons spilled over this period, it can be seen that OBM spillages make up nearly 46% of the overall volume spilled. OBMs will not be used during the proposed Cambo wells, removing the risk of this type of spill.

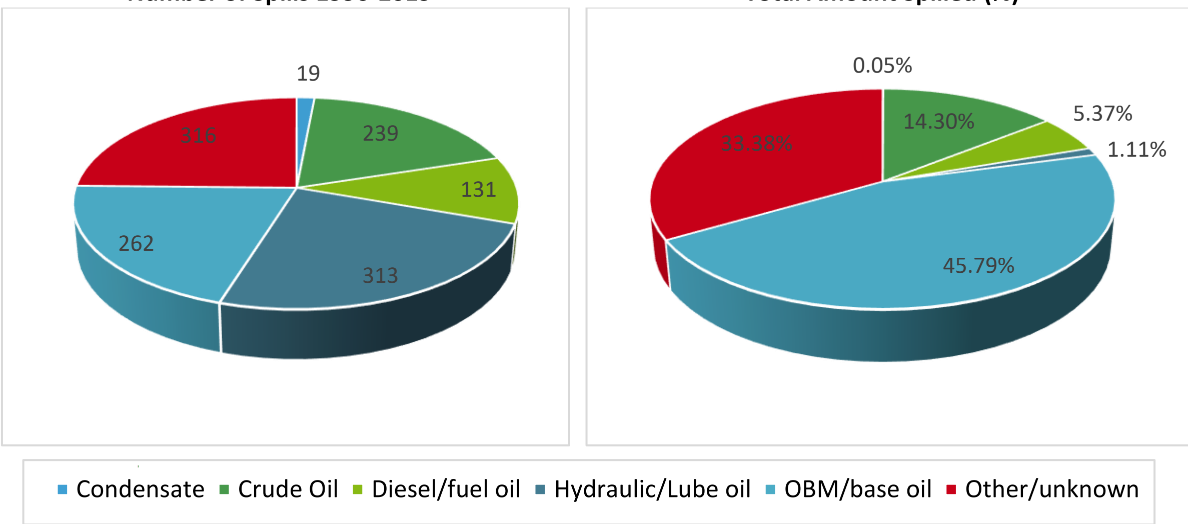

Figure 13.1: Oil Spills on the UKCS from MODUs Between 1990 and 2019

Source: Fugro, 2019.

Using data presented in HSE (2007), it can be calculated that on average, the probability of an oil spill from a MODU is 0.0015 spills per rig day, or one spill every 647 rig days. Extrapolating these statistics to the proposed Cambo wells, which are estimated to take between 37 and 61.6 days to drill and complete each, suggests a 5.6% to 9.2% chance of a spill per well.

Next to frequency, the size of a potential hydrocarbon spill is also very important in spill response planning. Figure 13.2 illustrates the proportion of oil spills from MODUs which fall into each of three size categories. The dataset shows that the majority of spills (82.9%) are smaller than 1 tonne (Fugro, 2019). It is expected that the response to a spill of this size could be undertaken and fully managed by the MODU itself, requiring only monitoring while the slick evaporates and disperses naturally.

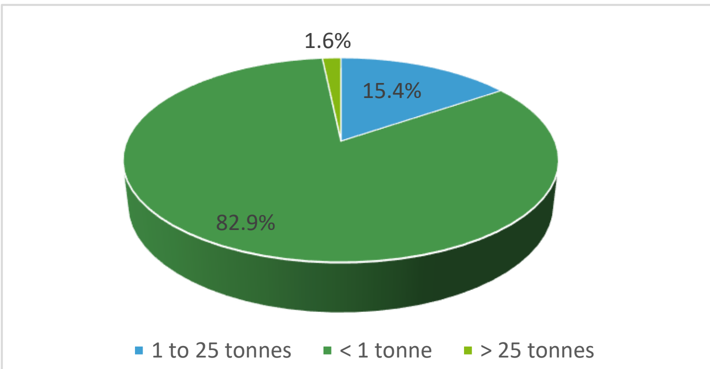

Figure 13.2: Percentage of Hydrocarbon Spills from MODUs, by Size, Between 1990 and 2019

Source: Fugro, 2019.

Uncontrolled Well Blow-out

The probability of an uncontrolled well blow-out event occurring is very low. Well blow-outs resulting in the uncontrolled release of hydrocarbons have happened too infrequently on the United Kingdom Continental Shelf (UKCS) for a meaningful analysis of the historic frequency to be carried out. However, the following paragraphs give a brief overview on historic well control events on the UKCS.

Prior to 1990, only two significant uncontrolled blow-outs occurred in the North Sea. These events occurred during drilling operations on the West Vanguard semi-submersible on the Norwegian continental shelf and on the Ocean Odyssey semi-submersible on the UKCS, during 1985 and 1988 respectively (DTI, 2007). Both blow-outs involved gas and did not result in hydrocarbon spills to sea. Moreover, lessons learnt from these events resulted in major legislative and operational changes for offshore drilling on the UKCS to prevent such events from happening again.

Between 1990 and 2007, a total of 343 well incidents were recorded from MODUs (both drilling and production). These incidents included several issues of varying severity, but only 17 resulted in loss of well control. This translates to 0.00004 incidents per rig day, or one incident every 26,827.5 rig days. Furthermore, none of the 17 recorded incidents resulted in an uncontrolled well blow-out with a crude oil spill of any size (OGUK, 2009).

The most recent well control incident in the North Sea involved a gas and condensate blow-out from Well 22/30c-G4, located close to the Elgin Platform, in March 2012. This incident resulted in the temporary cessation of production from the Elgin/Franklin area. SPE will review the lessons learnt from this incident, with consideration to the proposed drilling operations at Cambo.

13.2.1 Diesel Spills

Diesel spills from mobile drilling units account for 5.37% of oil spilled on the UKCS from MODUs (Figure 12.1). Diesel will be the main fuel used for power generation during the proposed drilling operations and, therefore, will be the largest volume of hydrocarbons stored on the MODU. Historical oil spill data indicate that the probability of a diesel spill is 0.0002 spills per day, or one spill in every 4,719 days. When extrapolating this probability to the Cambo wells, this equates to a probability of between 0.78% and 1.3% of a diesel spill occurring (Fugro, 2019; HSE, 2007).

Spill records indicate that most diesel spills tend to occur during bunkering operations and that they are mostly caused by hose failures. Therefore, the volumes of diesel spilled tend to be relatively small. For example, of the 132 recorded diesel spills, 119 (90.2%) were less than 1 tonne (Fugro, 2019). If a diesel spill of this size were to occur, it is likely that only onsite response personnel and equipment would be required to control the incident, due to the tendency of diesel to evaporate and disperse relatively quickly from the sea surface (see Section 13.4). Only three of the recorded diesel spills were greater than 5 tonnes, and each of these also occurred during bunkering operations.

The worst-case scenario, complete loss of the diesel inventory, will only occur as a result of a major accident, such as a catastrophic collision with another vessel. The probability of such an event occurring is very low, particularly with the low vessel traffic in this area (see Section 4.6.4).

13.3 Likelihood of a Hydrocarbon Spill from the FPSO

Historical data, covering the period between January 1990 and April 2019, indicate that the possibility of a large hydrocarbon spill from an FPSO operating on the UKCS is very low. In contrast to spillages from MODUs, the largest number of spills from FPSO are from crude oil (Figure 13.3). Looking at the overall volume of hydrocarbons spilled over this period, it can be seen that crude oil spillages make up just over 47% of the overall volume spilled. However, individual spills are typically quite small spillages, with 616 (89.4 %) out of 689 recorded spills being less than 1 tonne (Figure 13.4).

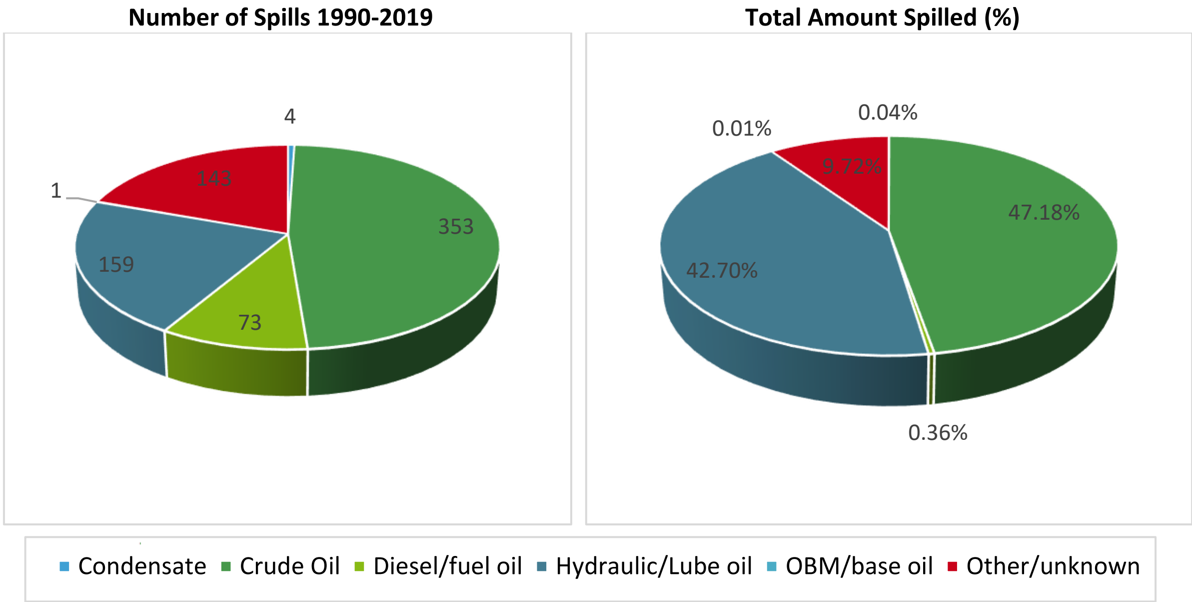

Figure 13.3: Oil Spills on the UKCS from FPSOs Between 1990 and 2019

Source: Fugro, 2019.

Using data presented in HSE (2007) and Fugro (2019), it can be calculated that on average, the probability of an oil spill from a FPSO is 0.017 spills per day, or one spill every 60.5 days. It should be noted that the vast majority (89.4%) of FPSO spills are small. It is expected that the response to a spill of this size could be undertaken and fully managed by the FPSO, itself, requiring only monitoring while the slick evaporates and disperses naturally.

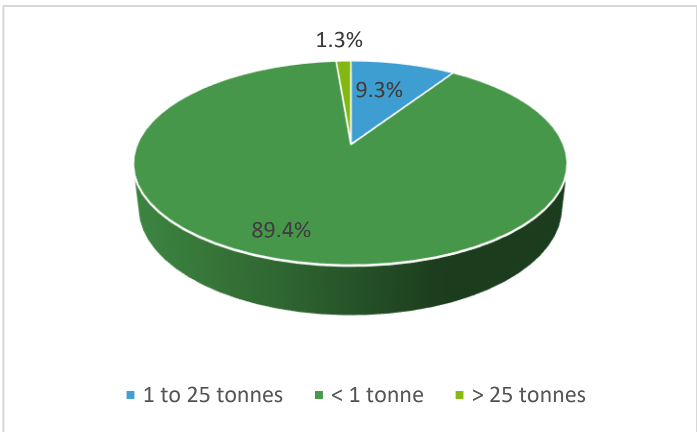

Figure 13.4: Percentage of Hydrocarbon Spills from FPSOs, by Size, Between 1990 and 2019

Source: Fugro, 2019.

13.4 The Fate and Behaviour of a Hydrocarbon Spill at Sea

Oil characteristics, spill location and the wave, wind and current conditions all govern the fate of spilled hydrocarbons. The behaviour of hydrocarbons when released from the sea surface and from the seabed are described in the following section. During the proposed drilling operations, it is expected that the most likely release point for a release of reservoir hydrocarbons (crude oil and gas) would be at the seabed. Meanwhile, the most likely release point for a spill of crude from the FPSO storage tanks would be from the sea surface.

The fate of hydrocarbons spilled at sea is relatively well understood. As soon as oil is released, the weathering process begins and the oil begins to move across the sea surface. Oil characteristics, spill location and wave and wind conditions govern the fate of the spilled oil. These processes are described below.

13.4.1 Oil Spill Movement

Spreading

Due to the influence of gravity, oil starts to spread out over the sea surface as soon as it is spilled. Oil slicks can spread very quickly to cover extensive areas of the sea surface, the speed of which depends mainly on the viscosity of the oil. Lighter oils spread out more quickly than heavier crudes. Although a spill will spread quickly in the first few days, the processes of evaporation and dispersion quickly remove the lighter, more volatile and water soluble, fractions of a slick from the sea surface. Then, as only the heavier, more viscous fractions are left, slick spreading will slow down.

Initially an oil spill will spread out as a single slick, covering an increasingly larger area while the slick becomes correspondingly thinner. However, as the slick spreads further, it will start to break up into smaller breakaway slicks due to the wind and water movement. Wind and wave conditions West of Shetland can be regarded as very dynamic, due to a combination of the relatively high wind speeds and increased water movement, created by a combination of the wind speed and the large fetch across the Atlantic Ocean. As such, it is expected that a large oil slick in this area would tend to break up very quickly into smaller patches.

Direction of Movement

Wind and surface current speed and direction are the main parameters influencing the movement of an oil slick. Any oil slick will travel roughly at the same speed and direction as the surface water current, while the prevailing wind drives a slick downwind at 3% to 4% of the wind speed.

The ocean current regime in the Faroe-Shetland Channel is complex (Section 4.2.1), due to the bathymetry of the area and the interaction of a number of different water masses. On a broad scale, cold, dense bottom water from the Arctic Basin flows southwest along the channel floor, whilst warmer Atlantic water flows over the top of it to the northeast. This suggests that any slick occurring in the surface waters of the Faroe-Shetland Channel would move with the dominant current to the northeast.

Although offshore winds West of Shetland may blow from any direction, they most frequently originate from the southwest (Section 4.2.2). This also suggests that a slick occurring on the sea surface would generally be directed to the northeast by the wind.

13.4.2 The Weathering Process

When oil is released into the marine environment it undergoes a number of physico-chemical changes, some of which assist in the degradation of the spill, while others may cause it to persist. These changes are dependent upon the type and volume of oil spilled, and the prevailing weather and sea conditions. An overview of the main processes influencing the fate and behaviour of spilled oil at sea is given in Figure 13.5. Evaporation and dispersion are the two main mechanisms that act to remove oil from the sea surface.

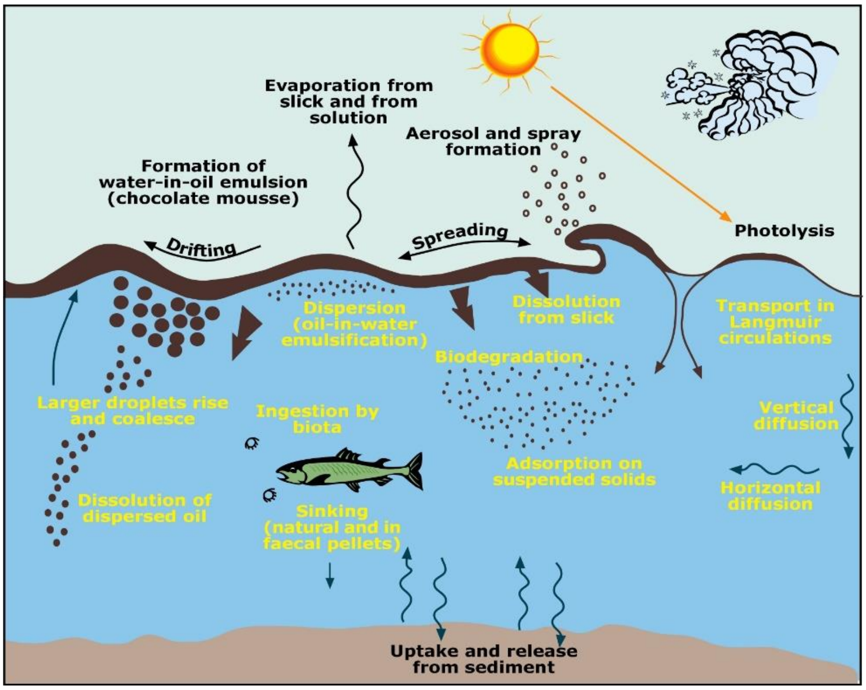

Figure 13.5: Fate and Behaviour of Spilled Oil at Sea

Evaporation

Following a hydrocarbon spill, evaporation is the initial predominant mechanism of reducing the mass of oil, as the light fractions (including aromatic compounds such benzene and toluene) evaporate quickly. Evaporation can cause considerable changes in the density, viscosity and volume of the spill. If the spilled oil contains a high percentage of light hydrocarbon fractions, a large part of it will evaporate relatively quickly in comparison to heavier oil.

Diesel displays very high evaporative losses upon exposure to air. Under ideal environmental conditions, i.e. a warm, sunny day with only moderate wind, a large proportion of the spill volume may be lost by evaporation in the first few hours after release. The evaporation process will be enhanced by warm temperatures and moderate winds.

Dispersion

After the light fractions have evaporated from the slick, natural dispersion becomes the dominant mechanism in reducing slick volume. The speed at which oil disperses is largely dependent upon the nature of the oil and the sea state. Lighter and less viscous oils tend to have more water soluble components, allowing them to mix and remain suspended within the water column.

The process of dispersion is dependent upon waves and turbulence at the sea surface, which can cause a slick to break up into fragments and droplets of varying sizes. This turbulence mixes these droplets into the upper levels of the water column, where some of the smaller droplets will remain suspended, while the larger ones will tend to rise back to the surface. Therefore, rough seas will break up a slick and disperse the oil at a faster rate than calm seas. There have been incidences of large oil spills being broken up and dispersed into the water column during large storm events, with little visible effect on the surrounding environment. As oil droplets are dispersed into the water column, the oil has a greater surface area which encourages the natural processes of dissolution, biodegradation and sedimentation.

Water movement at the sea surface is affected by wind speed. The West of Shetland area is a very active environment, with relatively high average wind speeds. Although wind speeds are generally reduced during the summer months, the sea state still reaches a Beaufort Force 5, a fresh breeze generating moderate waves, or greater for around 39% of the time. Water movement and wave size is also related to fetch, the distance over which the wind can blow without being interrupted. As the prevailing south-westerly winds blow uninterrupted across the Northeast Atlantic to the proposed Cambo Field Development, the waves this wind generates have the potential to become very large in size.

Emulsification

The immiscible components of an oil spill may either emulsify and disperse as small droplets in the water column (an oil-water emulsion) or aggregate into tight water-in-oil emulsions, often referred to as 'chocolate mousse'. The rate at which this happens, and the type of emulsion formed, is dependent upon the oil type, sea state and the thickness of the oil slick. Large, thick oil slicks tend to form water-in-oil emulsions, while smaller thinner slicks tend to form oil-in-water emulsions that usually disappear by natural dispersion. In practice, usually only one of the two processes will dominate.

When a water-in-oil emulsion (chocolate mousse) is formed, the overall volume of the slick increases significantly, as it may contain up to 70 or 80% water. This chocolate mousse will form a thick layer on the sea surface reducing slick spreading and inhibiting natural dispersion. The formation of this thick layer causes the surface area available to weathering and degradation processes to diminish, which can make 'chocolate mousses' difficult to break up using dispersants. In their emulsified form, and with their drastically increased volume, they can also cause difficulties for mechanical recovery devices. A water-in-oil emulsion is therefore very unlikely to occur in diesel spills, for example.

13.4.3 Oil Spill Modelling

The amount of time a hydrocarbon spill remains on the sea surface before becoming insignificant, and the extent to which it spreads from the point of release, may dictate the severity of any impacts on the marine life, particularly seabirds. Whether it reaches the shore is also a major consideration, due to the sensitivity of the nearest coastlines at Shetland and Orkney, and the additional clean up resources required. Both deterministic and stochastic oil spill modelling has been conducted to provide information on whether a spill might beach, and if so, how much time this would take. In view of this, the end points for the oil spill risk assessment are considered to be:

- Probability of oil reaching a shoreline, or crossing a median line to reach international waters;
- Minimum time taken for oil to reach a shoreline or crossing a median line to reach international waters.

Stochastic oil spill modelling has been conducted to assess these two criteria. Stochastic oil spill modelling is based on actual statistical wind speed and direction frequency data and provides a probability range of sea surface oil and beaching, representative of the prevailing conditions.

All modelling has been undertaken using SINTEF's Oil Spill Contingency and Response (OSCAR) model (Version 9.0.1). As discussed in Section 13.1, the two scenarios which may result in a large release of hydrocarbons to sea are an uncontrolled well blow-out, or a catastrophic failure of the FPSO storage tanks. Both scenarios would result in the release of a large crude oil spill. Modelling has therefore been undertaken for both of these scenarios.

Oil spill modelling for both scenarios has been carried out for all four seasons i.e. winter, spring, summer and autumn. This provides a range of risk profiles throughout the year in the event of a delay to operations.

Uncontrolled Well Blow-out

The parameters used in the modelling on an uncontrolled well blow-out are detailed in Table 13.1. The results of the well blow-out modelling scenario are provided in Table 13.2.

Minimum arrival time of surface oiling is shown in Figure 13.6 and the probability of surface oiling in Figure 13.7. It should be noted that surface oiling is shown with a thickness threshold of 0.3 micro-metre (µm) (equal to 0.0003 mm), in accordance with OPRED's oil spill modelling requirements. Potential impacts relating to the modelling results are described in Section 13.5.

Table 13.1: Well Blow-out Modelling Parameters

<table>
<tr><th colspan="9">Well Blow-out Parameters</th></tr>
<tr><td colspan="2">Loss from Well/FPSO/Rig/Other</td><td colspan="3">Well</td><td colspan="2">Instantaneous Loss?</td><td colspan="2">No</td></tr>
<tr><td colspan="2">Worst Case [m³]</td><td colspan="3">109,948 m³ / 30 days</td><td colspan="2" rowspan="2">Will the Well Self-Kill?</td><td colspan="2" rowspan="2">No</td></tr>
<tr><td colspan="2">Flow Rate [m³/day]</td><td colspan="3">Day 0 to 5: 5,239 m³
Day 6 to 10: 3,806 m³
Day 11 to 20: 3,356 m³
Day 21 to 30: 3,117 m³</td></tr>
<tr><td colspan="2">Justification for Predicted Worst Case Volume</td><td colspan="7">It would be expected to take 30 days to install the well capping device</td></tr>
<tr><th colspan="9">Location</th></tr>
<tr><td colspan="2">Spill Source Point</td><td colspan="7">60° 48' 34.453" N, 4° 10' 31.998" W</td></tr>
<tr><td colspan="2">Installation/Facility Name</td><td colspan="3">Well P3</td><td colspan="2">Quad/Block</td><td colspan="2">204/10a</td></tr>
<tr><th colspan="9">Hydrocarbon Properties</th></tr>
<tr><td colspan="2">Hydrocarbon Name</td><td colspan="7">Cambo</td></tr>
<tr><td colspan="2">Assay Available</td><td colspan="3">Yes</td><td colspan="2">Was An Analogue Used For Spill Modelling?</td><td colspan="2">Yes</td></tr>
<tr><td></td><td>Name</td><td>ITOPF Category</td><td>Specific Gravity</td><td>API Gravity</td><td>Viscosity [cP]</td><td>Pour Point [°C]</td><td>Wax Content [%]</td><td>Asphaltene Content [%]</td></tr>
<tr><td>Hydrocarbon</td><td>Cambo crude</td><td>3</td><td>0.918</td><td>25.4</td><td>600</td><td>-36</td><td>8.4</td><td>0.35</td></tr>
<tr><td>Analogue</td><td>Schiehallion</td><td>3</td><td>0.899</td><td>25.9</td><td>180</td><td>3</td><td>7.0</td><td>0.36</td></tr>
<tr><th colspan="9">Metocean Parameters</th></tr>
<tr><td colspan="2">Air Temperature (°C)</td><td colspan="3">2°C to 15°C</td><td colspan="2">Sea Temperature (°C)</td><td colspan="2">7°C to 15°C</td></tr>
<tr><td colspan="2">Wind Data</td><td colspan="7">2 years' (2012 to 2013) Oil & Gas UK Data from the European Centre for Medium-Range Weather Forecasts (ECMWF) Wind Data</td></tr>
<tr><td colspan="2">Current Data</td><td colspan="7">2 years' (2011 to 2013) Oil & Gas UK Data: Shelf daily currents</td></tr>
<tr><th colspan="9">Modelled Release Parameters</th></tr>
<tr><td colspan="2">Surface or Subsurface</td><td colspan="3">Subsurface</td><td colspan="2">Depth [m]</td><td colspan="2">1,082 m</td></tr>
<tr><td colspan="2">Release Duration [days]</td><td colspan="3">30 days</td><td colspan="2">Instantaneous?</td><td colspan="2">No</td></tr>
<tr><td colspan="2">Persistence Duration [days]</td><td colspan="3">45 days</td><td colspan="2">Release Rate [m³/hour]</td><td colspan="2">Day 0 to 5: 218 m³
Day 6 to 10: 159 m³
Day 11 to 20: 140 m³
Day 21 to 30: 130 m³</td></tr>
<tr><td colspan="2">Total Simulation Time [days]</td><td colspan="3">45 days</td><td colspan="2">Total Release [m³]</td><td colspan="2">109,948 m³</td></tr>
<tr><th colspan="9">Oil Spill Modelling Software</th></tr>
<tr><td colspan="2">Name of Software</td><td colspan="3">MEMW-OSCAR</td><td colspan="2">Version</td><td colspan="2">11.0.1</td></tr>
</table>

Source: OSRL, 2020a.

Table 13.2: Well Blow-out Modelling Results

Well Blow-out Modelling Summary				
Spill Scenario/Descriptor	Cambo P3 well blow-out			
Median Crossing				
Identified Median Line	**Highest Probability and Shortest Time to Reach**			
	Dec to Feb	Mar to May	Jun to Aug	Sep to Nov
Faroe Islands	100%	100%	100%	100%
	0 days, 3 hrs	0 days, 3 hrs	0 days, 3 hrs	0 days, 3 hrs
Iceland	10%	N/A	N/A	N/A
	29 days, 12 hrs	N/A	N/A	N/A
Norway	99%	59%	90%	100%
	6 days, 6 hrs	7 days, 15 hrs	9 days, 15 hrs	5 days, 15 hrs
Landfall				
Predicted Locations	**Highest Probability and Shortest Time to Reach**			
	Dec to Feb	Mar to May	Jun to Aug	Sep to Nov
The Faroe Islands	23%	72%	54%	5%
	8 days, 19 hrs	6 days, 11 hrs	8 days, 21 hrs	11 days, 15 hrs
Norway	64%	2%	8%	49%
	22 days, 5 hrs	35 days, 3 hrs	33 days, 10 hrs	17 days, 11 hrs
The Shetland Islands (United Kingdom)	89%	63%	56%	56%
	6 days, 23 hrs	7 days, 2 hrs	7 days, 6 hrs	5 days, 0 hrs
The Orkney Islands (United Kingdom)	1%	10%	19%	N/A
	40 days, 6 hrs	14 days, 21 hrs	11 days, 9 hrs	N/A
Highland (United Kingdom)	N/A	10%	8%	N/A
	N/A	13 days, 14 hrs	27 days, 18 hrs	N/A
Eilean Siar (United Kingdom)	N/A	3%	N/A	N/A
	N/A	19 days, 12 hrs	N/A	N/A
Shoreline Impact				
Mass of oil onshore	333 MT	2,494 MT	3,382 MT	386 MT
Volume of oil onshore	370 m^3	2,774 m^3	3,762 m^3	429 m^3
Water content	73%	73%	73%	73%
Volume of emulsion onshore	1,372 m^3	10,275 m^3	13,933 m^3	1,590 m^3
Key Sensitivities At Risk				
Discussed in Section 13.5.4				

Source: OSRL, 2020a.

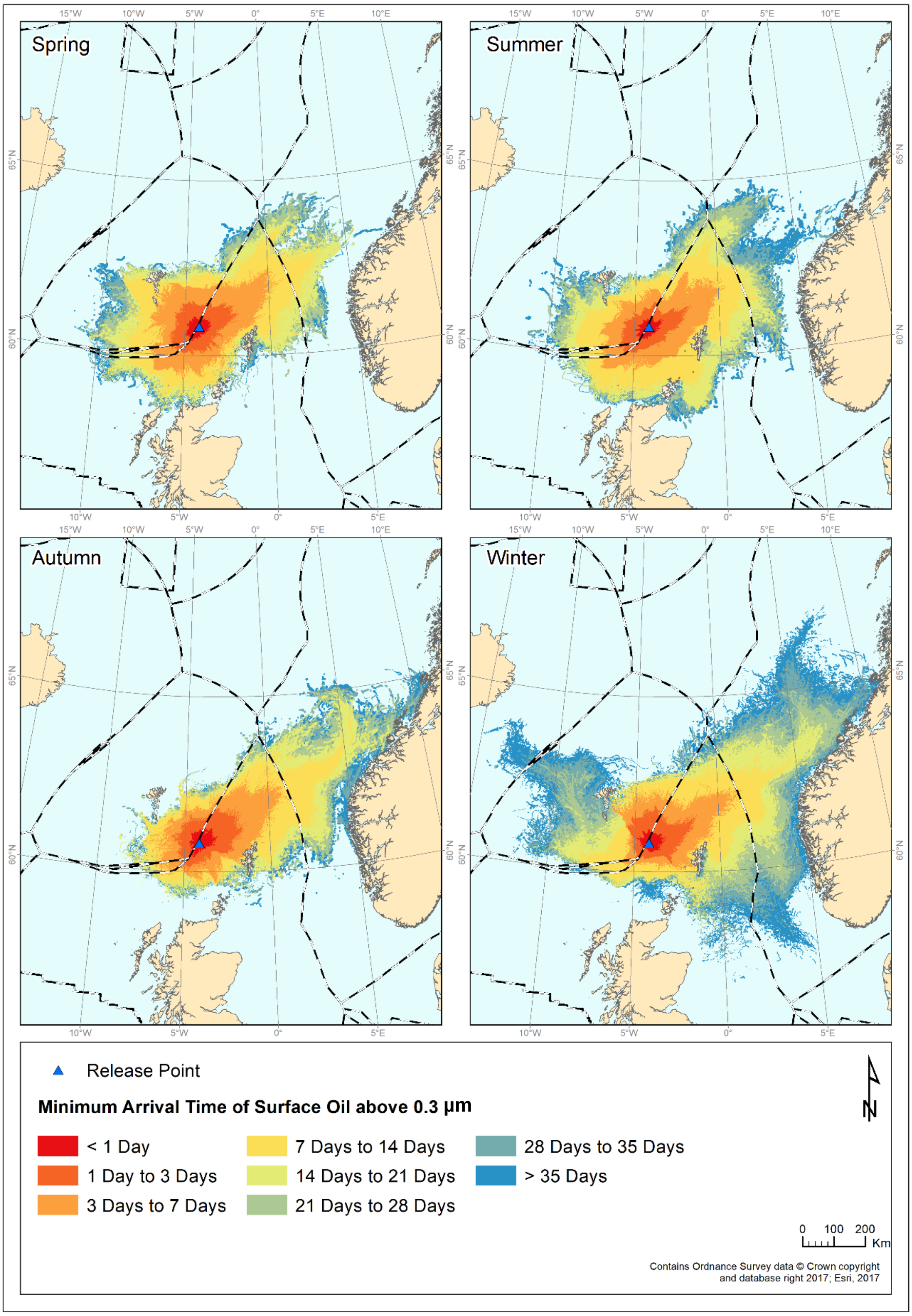

Figure 13.6: Well Blow-out Modelling: Arrival Time Plot

Source: OSRL, 2020a.

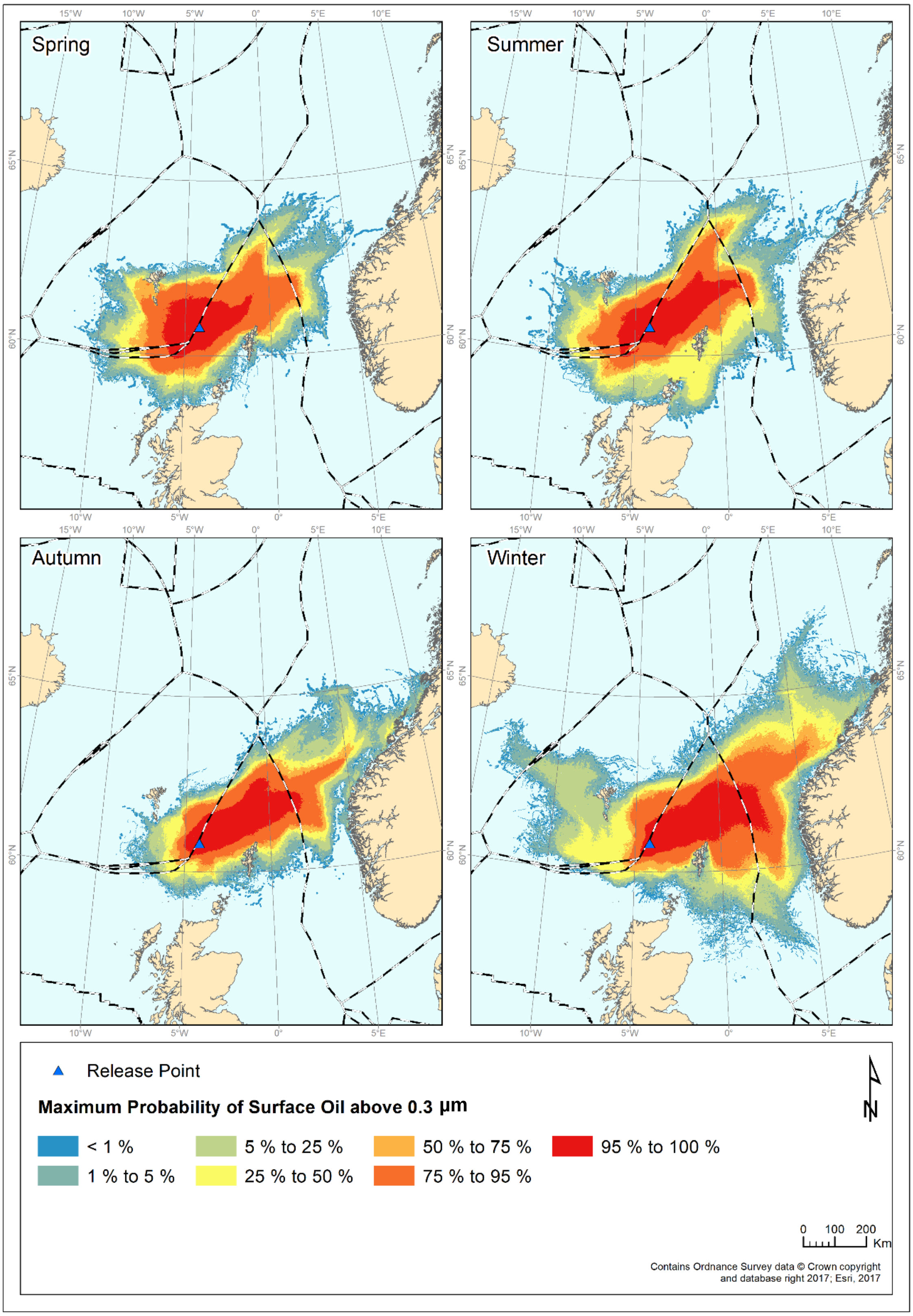

Figure 13.7: Well Blow-out Modelling: Probability of Surface Oil

Source: OSRL, 2020a.

Vertical Profile Modelling

In addition to the stochastic modelling detailed above, a vertical trajectory modelling run was undertaken, to provide a predication of the behaviour of crude oil in the water column in the event of a subsea blow-out release. The parameters used matched those used in the stochastic modelling, as detailed in Table 13.1.

The vertical profile shows the oil plume rising to the sea surface from the release depth of 1,082 m in approximately 2½ hours (Figure 13.8). The associated gas plume does not reach the sea surface, and is absorbed into the water column. As the small oil droplets encounter the thermocline at approximately 400 m below the sea surface, the speed of plume rising slows and some of the smaller droplets are halted. A sub-surface oil plume could potentially be trapped at this level, although the model does not show this outcome. Once the plume has risen to the surface, the plume model shows that it is likely to be driven by the Faroe-Shetland slope current that generally flows towards the north-east (towards Norway) all year around.

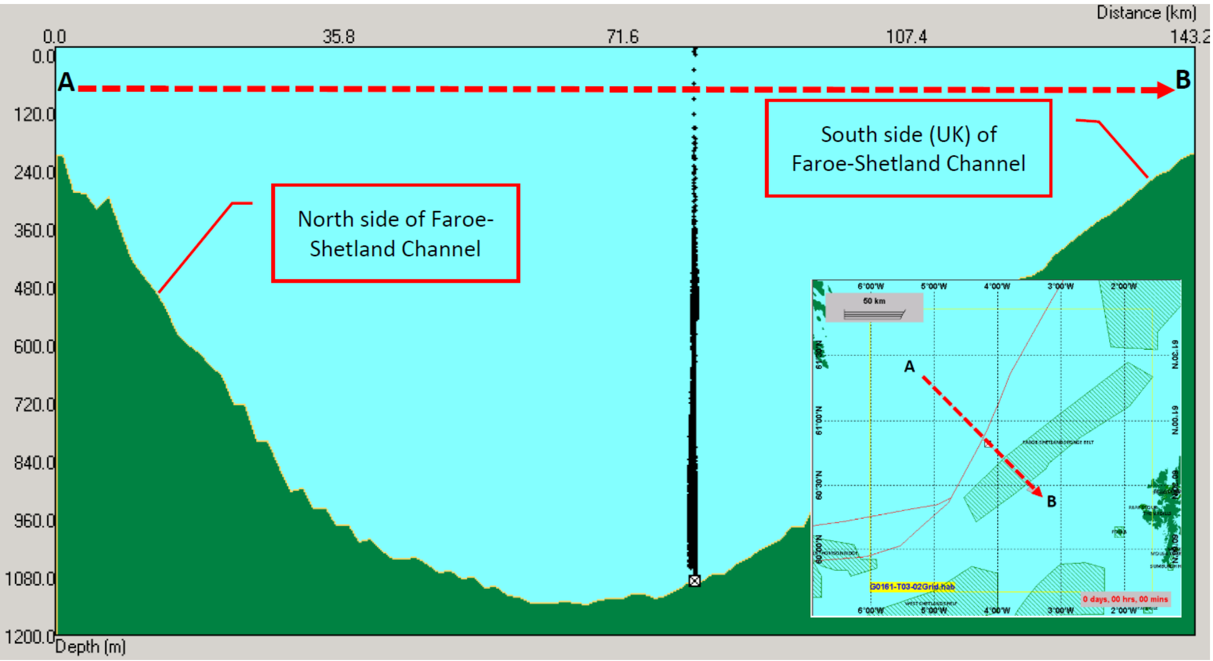

Figure 13.8: Vertical Movement of Cambo Crude Oil Plume

Source: OSRL, 2018a.

Complete Loss of FPSO Inventory

Guidance detailing oil spill modelling requirements states that the maximum possible inventory of crude oil onboard the FPSO (i.e. 103,342 m3) should be modelled as an 'instantaneous release' (BEIS, 2019). However, when attempting to model the maximum FPSO crude oil inventory as an instantaneous release (i.e. all oil is released in 1 second), this can result in unreliable modelling outputs in OSCAR. To avoid this, a more realistic worst-case maximum release rate of just over 1,000 m3/hr has been applied, with the release duration extended appropriately. This scenario represents an instantaneous release as closely as possible, without compromising the reliability of the modelling results.

Table 13.3: Complete Loss of FPSO Inventory Spill Modelling Parameters

FPSO Inventory Spill Parameters								
Loss from Well/FPSO/Rig/Other		FPSO		Instantaneous Loss?		No		
Worst Case [m^3]		103,342 m^3		Will the Well Self-Kill?		N/A		
Flow Rate [m^3/day]		1,003 m^3						
Justification for Predicted Worst Case Volume		Maximum FPSO Storage Inventory						
Location								
Spill Source Point		60° 48' 32.606" N, 004° 07' 15.914" W						
Installation / Facility Name		FPSO		Quad/Block		204/5		
Hydrocarbon Properties								
Hydrocarbon Name		Cambo						
Assay Available		No		Was An Analogue Used For Spill Modelling?		Yes		
	Name	ITOPF Category	Specific Gravity	API	Viscosity [cP]	Pour Point [°C]	Wax Content [%]	Asphaltene Content
Hydrocarbon	Cambo crude	3	0.918	25.4	600 cP	-36 °C	8.4 %	0.35 %
Analogue	Schiehallion	3	0.899	25.9	180 cP	3.0 °C	7.0 %	0.36 %
Metocean Parameters								
Air Temperature (°C)		2°C – 15°C		Sea Temperature (°C)		7°C – 15°C		
Wind Data		2 years' (2012 to 2013) Oil & Gas UK Data from the European Centre for Medium-Range Weather Forecasts (ECMWF) Wind Data						
Current Data		2 years' (2011 to 2013) Oil & Gas UK Data: Shelf daily currents						
Modelled Release Parameters								
Surface or Subsurface		Surface		Depth [m]		0 m (Surface)		
Release Duration [days]		103 hours		Instantaneous?		No*		
Persistence Duration [days]		20 days		Release Rate [m^3/hour]		1,003 m^3/hour		
Total Simulation Time [days]		20 days		Total Release [m^3]		103,342 m^3		
Oil Spill Modelling Software								
Name of Software		MEMW-OSCAR		Version		11.0.1		

Source: OSRL, 2020b.

**Although the guidance notes state that an instantaneous release rate should be modelled, in the case of such a large volume release, a longer release duration was used as it provides a more realistic approach and prevents possible errors within the model.*

The results of the FPSO inventory loss oil spill modelling scenario are provided in Table 13.4. Minimum arrival time of surface oiling is shown in Figure 13.9 and the probability of surface oiling in Figure 13.10. It should be noted that surface oiling is shown with a thickness threshold of 0.3 µm, in accordance with OPRED's oil spill modelling requirements.

Table 13.4: Complete Loss of FPSO Inventory Spill Modelling Results

Complete Loss of FPSO Inventory Modelling Summary				
Spill Scenario/Descriptor	FPSO Release			
Median Crossing				
Identified Median Line	**Highest Probability and Shortest Time to Reach**			
	Dec to Feb	Mar to May	Jun to Aug	Sep to Nov
Faroe Islands	85 %	94 %	82 %	74 %
	0 days, 3 hrs	< 1 hr	0 days, 3 hrs	0 days, 3 hrs
Norway	76 %	34 %	62 %	86 %
	6 days, 9 hrs	9 days, 9 hrs	7 days, 12 hrs	6 days, 21 hrs
Landfall				
Predicted Locations	**Highest Probability and Shortest Time to Reach**			
	Dec to Feb	**Mar to May**	**Jun to Aug**	**Sep to Nov**
UK (The Shetland Islands)	49 %	29 %	50 %	41 %
	5 days, 3 hrs	5 days, 13 hrs	5 days, 2 hrs	5 days, 3 hrs
Norway	N/A	N/A	N/A	3 %
	N/A	N/A	N/A	17 days, 14 hrs
Faroe Islands	N/A	23 %	11 %	4 %
	N/A	7 days, 2 hrs	7 days, 24 hr	9 days, 8 hrs
Shoreline Impact				
Mass of oil onshore	466 MT	808 MT	5,061 MT	1,184 MT
Volume of oil onshore	518 m^3	899 m^3	5,630 m^3	1,317 m^3
Water content	73 %	73 %	73 %	73 %
Volume of emulsion onshore	1,920 m^3	3,329 m^3	20,850 m^3	4,878 m^3
Key Sensitivities at Risk				
Sensitivities/Sites of Concern	**Highest Probability and Shortest Time to Reach**			
Faroe-Shetland Sponge Belt MPA	100 %	91 %	100 %	100 %
	0 days, 6 hrs	0 days, 6 hrs	0 days, 9 hrs	0 days, 6 hrs
North-East Faroe-Shetland Channel MPA	96 %	67 %	95 %	97 %
	2 days, 21 hrs	3 days, 15 hrs	3 days, 6 hrs	2 days, 15 hrs
West Shetland Shelf MPA	5 %	25 %	15 %	4 %
	11 days, 9 hrs	4 days, 12 hrs	5 days, 12 hrs	5 days, 15 hrs
North West Orkney MPA	10 %	27%	9 %	16 %
	6 days, 18 hrs	4 days,18 hrs	8 days, 21 hrs	6 days, 0 hrs
Pobie Bank Reef SAC	43 %	14 %	41 %	36 %
	7 days, 6 hrs	9 days, 15 hrs	7 days, 21 hrs	8 days, 6 hrs
Wyville Thompson Ridge SAC	9%	47%	19%	7%
	11 days, 6 hrs	2 days, 15 hrs	3 days, 18 hrs	10 days, 3 hrs
Darwin Mounds SAC	N/A	10%	8%	N/A
	N/A	7 days, 3 hrs	6 days, 15 hrs	N/A
Solan Bank Reef SAC	N/A	4%	N/A	N/A
	N/A	13 days, 9 hrs	N/A	N/A
Seas off Foula proposed SPA	5%	4%	5%	9%
	8 days, 12 hrs	12 days, 6 hrs	8 days, 0 hrs	5 days, 12 hrs
Hermaness, Saxa Vord and Valla Field SPA	44%	25%	49%	41%
	5 days, 3 hrs	5 days, 21 hrs	5 days, 3 hrs	6 days, 9 hrs
Fetlar SPA	22%	16%	25%	20%
	9 days, 3 hrs	8 days, 12 hrs	8 days, 0 hrs	9 days, 15 hrs
Fetlar to Haroldswick MPA	26%	16%	28%	22%
	9 days, 0 hrs	7 days, 15 hrs	8 days, 0 hrs	8 days, 18 hrs
Foula SPA	5%	4%	5%	9%
	8 days, 12 hrs	12 days, 6 hrs	8 days, 0 hrs	5 days, 12 hrs

Source: OSRL, 2020b.

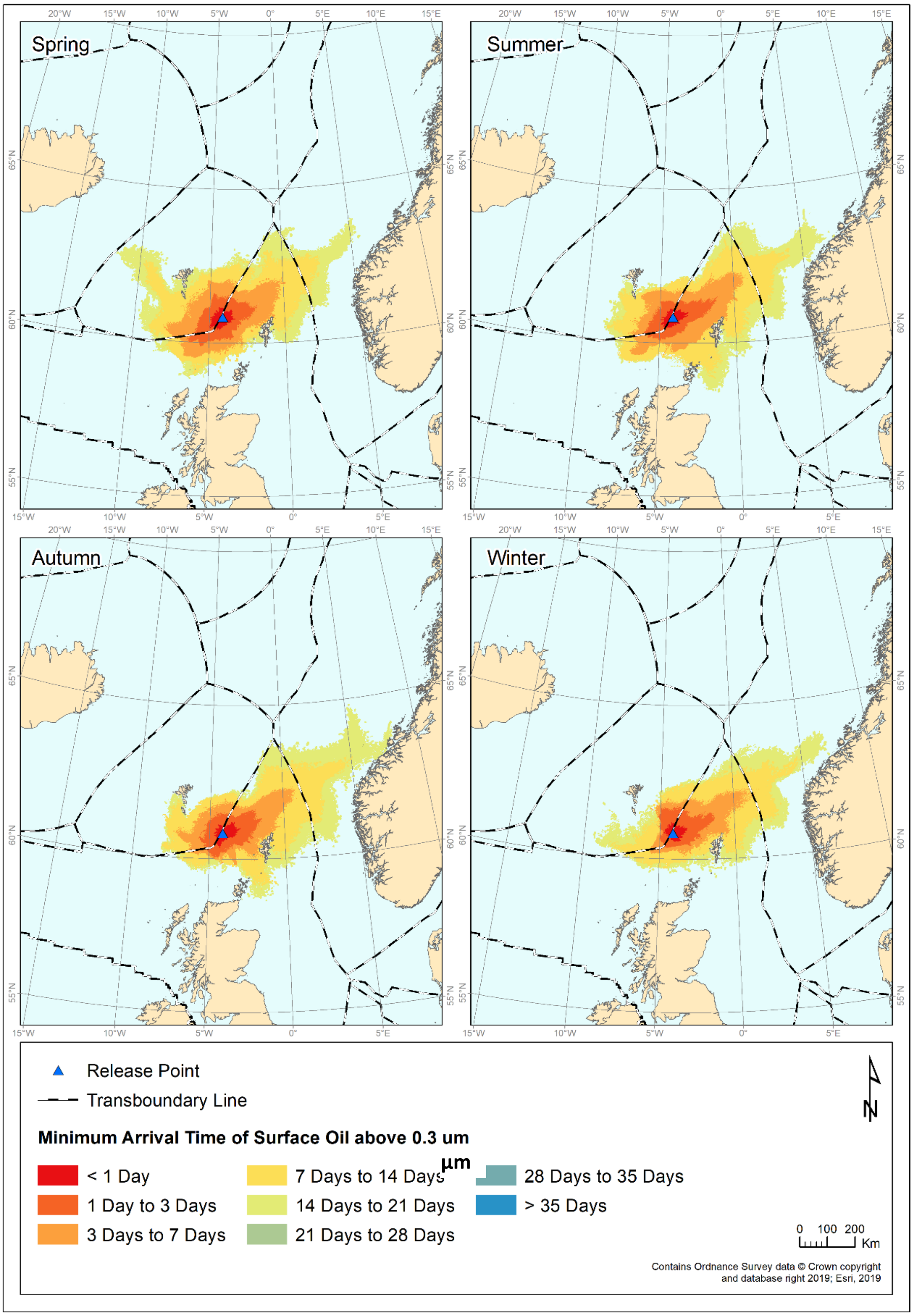

Figure 13.9: Complete Loss of FPSO Inventory Spill Modelling: Arrival Time Plot

Source: OSRL, 2020b.

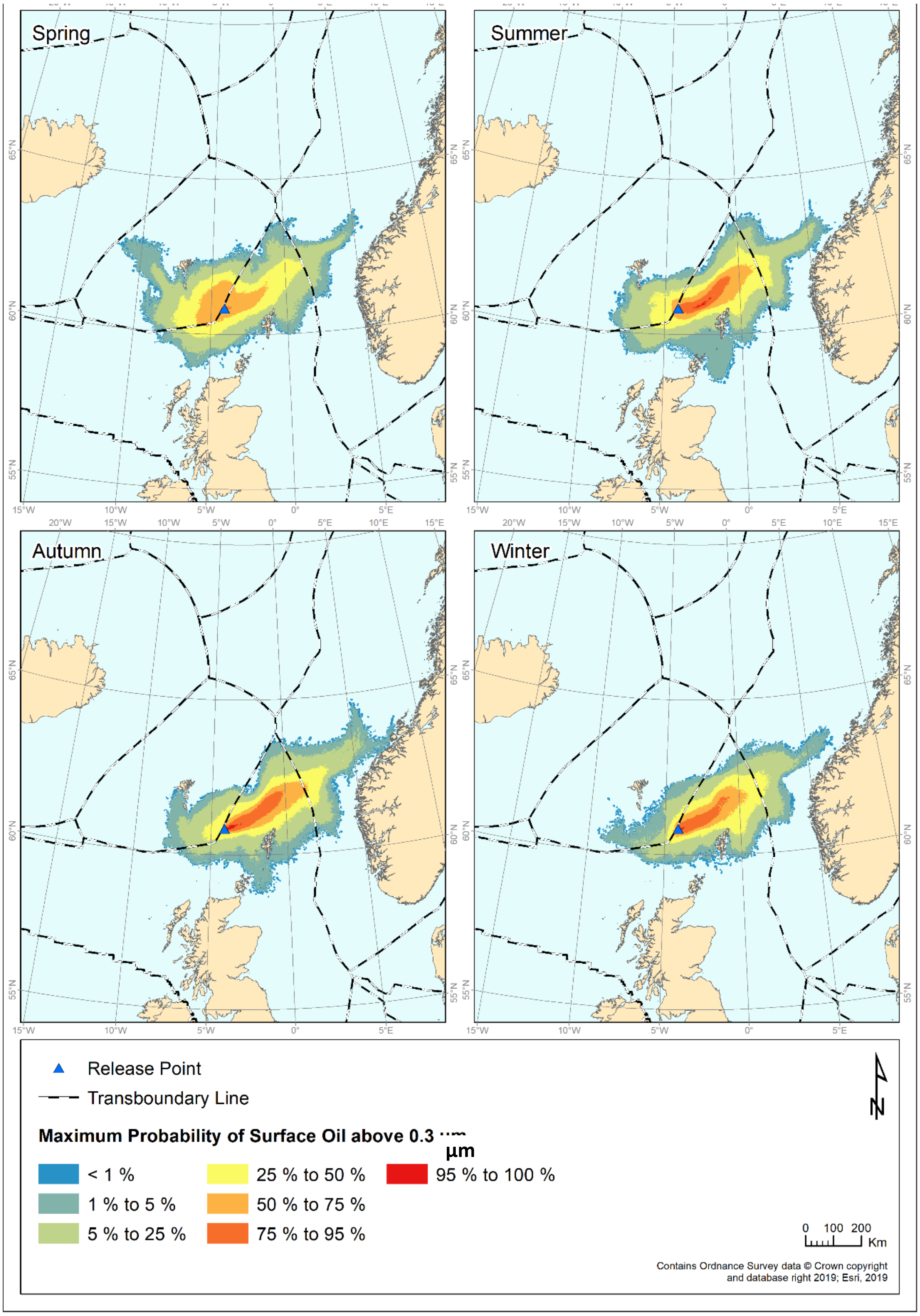

Figure 13.10: Complete Loss of FPSO Inventory Spill Modelling: Probability of Surface Oil

Source: OSRL, 2020b.

13.5 Potential Environmental Impacts

13.5.1 Impacts on Marine Life

The risk of accidental hydrocarbon spillage to the marine environment is one of the main environmental concerns associated with oil-industry activities. Although the effects of oil spills are well understood, the effects of each individual spill are unique and some assumptions have been made regarding predicting the effects of a large crude oil spill at the proposed Cambo Field Development.

Plankton

Oil, particularly diesel, is toxic to a wide range of planktonic organisms. Those living near the sea surface are particularly at risk, as water-soluble components leach from floating oil. Although oil spills may kill individuals, the effects on whole plankton communities generally appear to be short-term. Following an oil spill incident, plankton biomass may fall dramatically, due either to animal deaths or avoidance of the area. However, after only a few weeks, populations would be expected to return to previous levels through a combination of high reproductive rates and immigration from outside the affected area.

Benthos

Shallow Coastal Communities

It is generally assumed those animals associated with the seabed will remain unaffected by a surface slick as the floating oil moves above them. However, a fraction of the water soluble components of a slick may dissolve into the water column, assisted by rough seas or agitation of the sea surface, where these could potentially be harmful to benthic organisms. In deeper offshore areas, these impacts will be very limited. However, if the spilled oil drifts inshore, the benthic communities of the shallow coastal areas may be affected. Parameters such as local bathymetry and sediments types would significantly influence the distribution of oil contamination at the seabed.

It should be noted that any oil that reaches these shallow areas will have travelled a considerable distance through the water column and across the sea surface, and will therefore have been affected by the range of degradation processes described in Section 13.4. These mechanisms will have contributed to remove the various toxic components of the oil and the primary impact of the oil deposition on benthic communities is anticipated to be related to smothering. As the oil will also have become widely dispersed by this point, the physical effects of smothering are expected to be limited.

The shoreline itself is particularly susceptible to oil beaching. The potential impacts arising from beached oil in coastal habitats are discussed separately in Section 13.5.2.

Deepwater Communities

As described above, the buoyancy of the produced oil (and associated gas) will carry all hydrocarbons straight up to the sea surface in the event of a subsea spill. Therefore, it is expected to be very unlikely for the crude oil to reach the surrounding benthic communities.

The habitats and associated benthic communities of the Faroe-Shetland Channel vary in relation to water depth, with a series of broad zones recorded (Section 4.3.1). The upper to mid continental slope is characterised by the presence of iceberg ploughmarks which, through infilling over time, create a complex mosaic of seabed habitats alternating between areas of cobbles and boulders, and fine sediment. These areas of boulders and cobbles can be extensive and support diverse epifaunal communities. Beyond this zone, few distinct features are supported and sediments become finer with increasing depth. As sediments become finer, the characteristic benthic species present change from largely suspension feeding to deposit feeding types.

Suspension feeders gather their food directly from the seawater and would, therefore, take in any oil present within the surrounding water leaving them more vulnerable to the toxic effects of oil dispersed in the water column. Deposit feeders are supported by the fine organic matter trapped between the fine sediments and these animals would only be affected if the dispersed oil settled on the seabed.

Any subsea release of crude oil would be pushed directly up in a plume to the sea surface, rather than towards the surrounding benthic communities. It would then be carried away from the spill location by the local current systems, with the majority of the oil moving to the northeast (Figure 13.7). Due to the time it would take to reach these areas and the large surface area available for microbial attack, it is expected that most of the toxic constituents would have been lost from the plume. It therefore seems unlikely that the released oil would significantly affect either suspension feeding or the more prevalent deposit feeding species comprising deep-water benthic communities.

No seabed features of conservation value have been recorded in the immediate area surrounding the proposed Cambo Field Development. The nearest area of conservation importance is Faroe-Shetland Sponge Belt Nature Conservation Marine Protected Areas (NCMPA), which lies 35 km southeast of the Development Footprint. Potential impacts of non-synthetic compound contamination (e.g. hydrocarbons) have been assessed using the Feature Activity Sensitivity Tool (FEAST) Tool. However, as stated above, it is expected that all spilled oil would be transported to the sea surface, and so benthic communities in the Faroe-Shetland Sponge Belt NCMPA would not be impacted in the event of a seabed spill.

Fish

Offshore fish populations remain relatively unaffected by oil pollution, as oil concentrations below the surface slick are generally low (Clark, 2001). There is also evidence that fish are able to detect and avoid oil-contaminated waters. This avoidance may, however, cause disruption to migration or spawning patterns.

Comparatively little is known about the distribution and abundance of deepwater fish species in the Faroe-Shetland Channel. Many of these species have slow growth rates, late onset of sexual maturity and low fecundity, leaving them vulnerable to the effects of disturbance.

Rather than impacting the fish directly, heavily contaminated sediments may have an adverse effect on local populations of demersal fish species, due to the impact it has lower down the food chain. However, as described in the benthos section above, heavy contamination of the sediments is not expected.

Fish eggs and larvae are more vulnerable to oil pollution than adult fish. In many fish species, these stages float to the surface where contact with spilt oil is more likely. A number of commercial species have spawning grounds in the Faroe-Shetland region (see Figure 4.18 in Section 4.3.3). However, as these species have extensive spawning grounds and produce large numbers of pelagic young, there is unlikely to be any long-lasting effect on numbers in the adult populations. Certain fish stocks may be more affected than others, particularly if the spill is very large, coincides with spawning periods, or enters the grounds of species with restricted spawning areas.

Shellfish

If oil reaches the seabed, shellfish species that cannot swim away from oiled sediments are susceptible to its effects. Mortalities may occur if shellfish become smothered by settling oil. Only low levels of oil in seawater may cause tainting in shellfish, which may be commercially damaging to shellfish fisheries. This is more common in filter feeding shellfish, principally bivalves, as they would take up fine oil droplets from the water column. In the deepwater of the Faroe-Shetland Chanel, commercially important shellfish are only found in very small quantities. Moreover, as explained above, it is extremely unlikely that any hydrocarbons released from a subsea blow-out would remain near the seabed. The inshore waters around Shetland do, however, support commercially important shellfish fisheries, which may be at risk if a spill reaches these waters.

Marine Mammals

Whales, dolphins, porpoises and seals are generally able to avoid a spill and are rarely affected significantly. However, if they do come into contact with a spill, possibly by surfacing in a slick to breathe, they may suffer from irritation of the eyes, mouth, nasal passages and skin. Volatile hydrocarbon fractions may also cause respiratory problems.

A thick layer of blubber protects cetaceans and adult seals from the cold and these animals are less vulnerable to the physical impacts of oil lowering their resistance to the cold. Seal pups and otters are, however, at risk from hypothermia if their fur becomes oiled and loses its thermal properties, as they do not have sufficient blubber underneath their fur to keep them warm. Both grey and common seals are known to breed on the Shetland and Orkney Islands (Section 4.3.4). The Shetland and Orkney Islands also support important otter populations. These marine mammals may be at risk if a slick reaches coastal areas.

Seabirds

Seabirds are particularly vulnerable to oil pollution at the sea surface which can cause a range of physical and physiological effects. Following contact with oil, seabirds risk loss of buoyancy and thermal insulation as the water-repellent properties of their plumage is lost. In an attempt to clean their plumage of the contaminating oil seabirds can also ingest the oil when preening, which may lead to an array of physiological effects. In addition to the direct mortality of adult birds only small quantities of ingested oil can have an indirect effect on reproduction, with depressed egg production and reduced hatching success.

The aerial habits of the fulmar and gulls, together with their large populations and widespread distribution, reduce vulnerability of these species. Gannets, skuas and auk species are considered to be most vulnerable to oil pollution due to a combination of heavy reliance on the marine environment, low breeding output with a long period of immaturity before breeding, and the regional presence of a large percentage of the biogeographical population (DTI, 2003).

The vulnerability of bird species to oil pollution is dependent on several factors and varies considerably throughout the year. The JNCC has produced a Seabird Oil Sensitivity Index (SOSI) which identifies areas at sea where seabirds are likely to be most sensitive to oil pollution. The SOSI uses seabird survey data collected between 1995 and 2015, in addition to individual species sensitivity index values, combined at each location to create a single measure of seabird sensitivity to oil pollution (JNCC, 2017c).

Monthly vulnerability for seabirds in the area around the proposed Cambo Field Development is presented in Table 13.5 and Figure 13.11. With increasing distance from shore, seabird abundance decreases, and their distribution becomes increasingly patchy. These patterns are generally governed by the availability and distribution of prey, and also oceanographic features such as water depth and sea temperature. As a result, in the deepwater of the Faroe-Shetland Channel, and well over 100 km from either the Shetland or Faroe Islands, seabird abundance in the area of the proposed development remains relatively low throughout the year.

The vulnerability of birds in the vicinity of the proposed Cambo Field Development is low to medium during the breeding season, generally between March and June, when large numbers of birds congregate in coastal breeding colonies (RSPB, 2018; Table 13.5; Figure 13.11). Seabird vulnerability in the area is generally, high to extremely high in September and November, possibly in association with the movement away from colonies after breeding. The vulnerability is increased by the numbers of auks, primarily guillemots, but also puffins, found at sea during this time (BODC, 1998; DTI 2001). Congregating into large groups referred to as 'rafts', these birds undergo a full moult at sea, rendering them flightless and leaving them highly susceptible to surface pollution (RSPB, 2018).

Table 13.5: Seabird Vulnerability to Surface Pollution in the Vicinity of the Proposed Development (JNCC, 2018)

UKCS Block	January	February	March	April	May	June	July	August	September	October	November	December
212/30	5	5*	5*	5	5	3	4	5	1	5	5*	5
213/26	5	5*	3	4	5	5	4	5	2	2*	5	5
204/4	5	5*	5*	5	5	5	5*	5	1	5	5*	5
204/5	5	5*	5*	5	4	4	5	5	1	5	5*	5
204/8	5	5*	5	4	4	5	5*	5	5	5	5	5
204/9	5	5	5	4	5	5	5*	5	2	5	2	5
204/10	5	5	4	4	5	4	5	5	1	5	5*	5
204/13	4	4	5	4	4	5	5*	5	5	5	5	5
204/14	5	4	5	4	4	5	5	5	5	5	3	5
204/15	5	5	5	4	5	4	5	5	5	5	2	5
205/1	5	5*	4*	4	3	5	5	5	3	5	5	5
205/6	5	5*	5	4	4	5	5	5	3	5	5	5
205/11	5	5	5	4	4	4	5	5	5	5	3	5

1	Extremely High	2	Very High	3	High	4	Medium	5	Low
ND	No data	*	Indicates blocks for which no data was available, and therefore score has been calculated using that of an adjacent month or Block						

Seabird vulnerability in the inshore waters around Orkney and Shetland are classified as high to very high throughout the year due to breeding seabirds foraging. The Shetland, Orkney and Faroe Islands are of international importance for the seabird breeding colonies they support, with many coastal sites and their surrounding inshore waters designated as Special Protection Areas (SPAs) under the European Birds Directive. These colonies may be at risk from a large surface slick.

Overall, the average for Blocks 204/4, 204/5, 204/9 and 204/10 shows a medium vulnerability to oil and surface pollutants, with a peak in vulnerability occurring in September (JNCC, 2018).

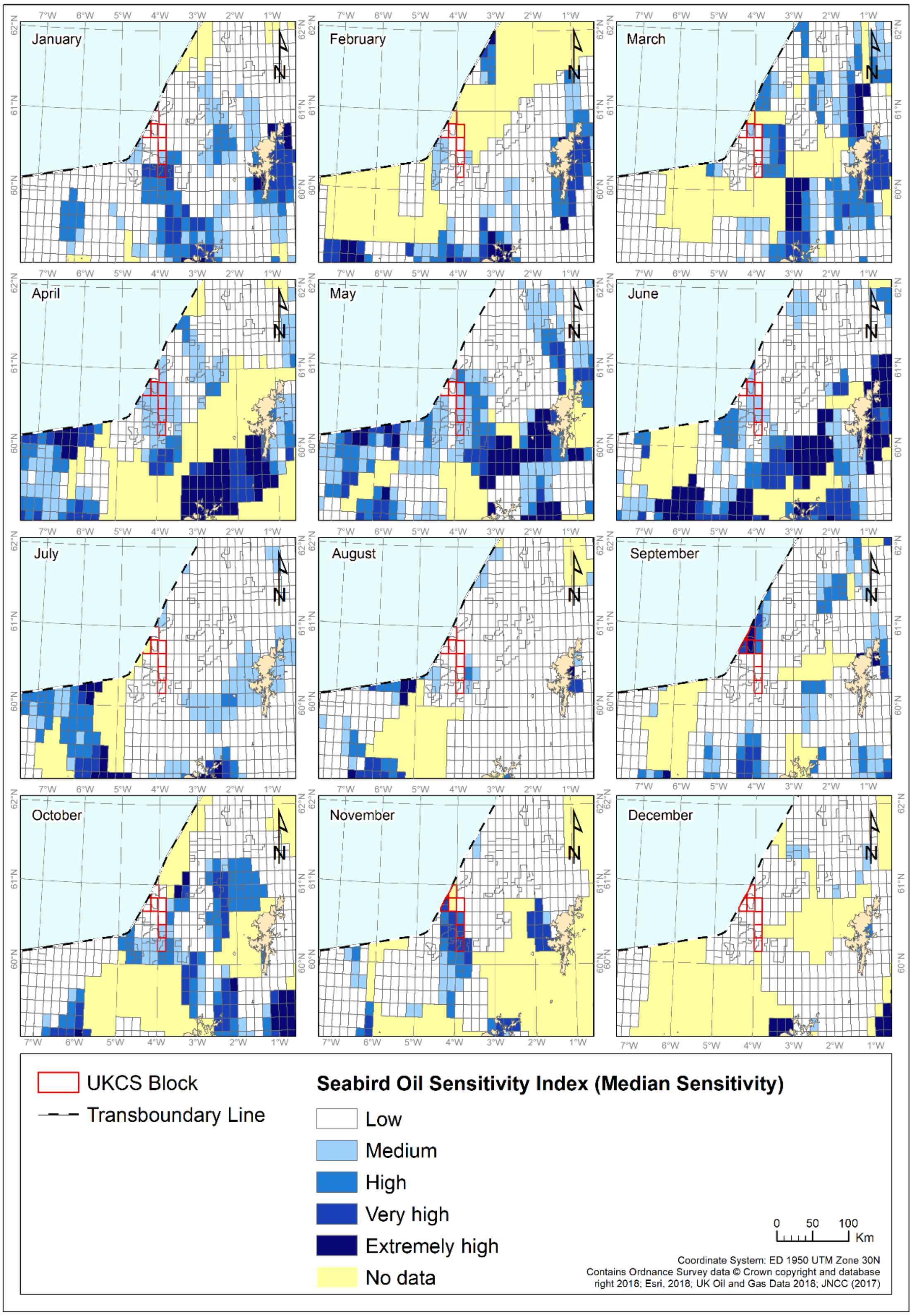

Figure 13.11: Seabird Vulnerability to Surface Pollution in the Vicinity of the Proposed Cambo Field Development

Source: JNCC, 2017c.

13.5.2 Impacts on Coastal and Inshore Habitats

The coastlines of the Shetland, Orkney and Faroe Islands support a range of different habitat types. These coastlines are important for nature conservation, with numerous sites along the coastline designated under national and international legislation (Section 4.5.1). In the unlikely event of a large spill, these coastlines are potentially at risk. Although the probability of a spill reaching shore, and the amount of crude oil that would do so, is very low.

Rocky Shores

Rocky shores can be very varied in structure, ranging from exposed vertical walls to flat bedrock, or stable boulder fields to aggregations of cobbles. These shores can support a variety of sessile animal and plant communities which live attached to the rock surface, as well as a range of associated mobile invertebrates and fish. More exposed rocky shores are generally dominated by sessile animals and smaller more robust seaweeds, while the more sheltered shores are characterised by the large brown kelps.

Rocky shores are generally high energy beaches and, while oil may have an impact on the animals and plants which live on them, stranded oil is often quickly removed by wave action and water movement. The vulnerability of rocky shore habitats to oiling is dependent on the type of rocky shore and its exposure. The action of the waves may start to remove the oil from an exposed vertical wall almost immediately but the oil may remain for longer in more sheltered, kelp dominated areas.

Many of the animals and small seaweeds found on rocky shores would be killed by exposure to fresh and light oils, but much of the crude oil potentially reaching the shore from a large spill from a spill at the proposed Development location would have been at sea for several days (3 to 7 days) and would have lost most of its toxic constituents. Various shoreline species have been observed to survive shoreline oiling and continue feeding in oiled areas, suggesting that the toxic impacts would be minimal (Clark, 2001). However, even if the beached oil is relatively non-toxic, heavily weathered oil may still cause damage due to its physical properties. Large amounts of stranded oil may impact upon shoreline animals by smothering them. Those animal species that are large enough to protrude above the oil or can move away quickly may survive, but smaller species would be killed by inhibition of their feeding and respiration mechanisms. Many of the larger brown seaweeds which dominate the more sheltered rocky shores secrete mucus which would prevent oil adhering to them. However, if oil does adhere to the seaweed fronds, instead of killing the seaweeds directly, the oil will increase their overall weight causing them to be pulled from the rocks by the wave action.

The rate of recovery and the form it takes will depend upon the type of rocky shore and the animals and plants that live on it. The general experience of oil spills on rocky shores is that substantial recovery can be achieved within two years, but biological factors may intervene and cause a prolonged change. Rocky shores are high energy, highly productive environments, where the physical and biological factors exerted upon them lead to intense competition between the species which live there. The physical factors, such as desiccation, extremes of temperature, and changes in salinity, can cause mortalities in rocky shore communities, while the severe winter storms can pull many animals and plants from the shore each year (Little and Kitching, 1996). As a result, these communities, particularly those on the coastlines surrounding the highly dynamic west of Shetland area, have the capability to regenerate quickly in order to take advantage of the newly available space.

Oil spill modelling indicates that, under the majority of meteorological circumstances, a large oil slick will drift northeast of the Cambo Field Development, leaving the coasts of Shetland and Norway under the greatest threat (Section 13.4.3). The coastlines of the Orkney and Faroe Islands may also be affected. During spring and summer time the northern coasts of the Isle of Lewis and the Scottish mainland may also be at risk. These shores are all dominated by steep sea cliffs and high energy rocky shores (Section 3.3). It could therefore be assumed that these northerly rocky shores could recover relatively quickly from a beaching oil spill.

Sedimentary Shores

The fate of oil stranded on sediment shores depends on the nature of the substratum (IPIECA, 2008). Due to the increased sediment movement and relatively large gaps between the particles, beached heavy oil can penetrate further into the more mobile shingle or coarse sand shores. These coarse sediment shores tend to be less productive than sheltered mudflats, where waterlogged sediments, rich in organic matter, can accommodate huge numbers of invertebrates. Gaps between the shingle or sand grains allow the water to drain away quickly between the tides and the movement of the sediment itself is very abrasive, meaning few animals can survive in it. If the beaching of an oil spill becomes inevitable, sandy beaches have in the past been considered as sacrificial areas. A spill may be directed towards a sandy beach in order to protect other, more sensitive, shorelines. Soft sediment areas are rare on the Shetland Islands, with sandy beaches making up less than 5% of the total coastline (Section 4.4.1).

In contrast, oil does not readily penetrate the sediments in areas of firm waterlogged mud or fine sand and tends to be carried away with the next tide (Clark, 2001). However, there is a concern over oil beaching on sheltered mudflats or associated sensitive areas of saltmarsh and these are often priority areas for protection following oil spills. These are generally highly productive areas, with high numbers of invertebrates living within the sediments which may provide a valuable food source for juvenile fish and birds (Little, 2000). Recovery times tend to be longer in these sheltered areas, due to the reduced bacterial degradation and persistence of the oil, particularly if it penetrates into the sediment (IPIECA, 2008). The process of cleaning the sediments and vegetation can be very difficult in these areas and could potentially exacerbate any damage to the habitat. In the most sheltered of intertidal areas, where very fine sediments accumulate, saltmarshes may be found. Small patches of saltmarsh are found at the heads of voes and in other very sheltered areas on the Shetland Islands, but these make up only 0.2% of the available coastline (Section 4.4.1).

13.5.3 Impacts on Other Users of the Sea

Commercial Fisheries

The effects of oil spills on commercial fish and shellfish, and the indirect impacts on their habitats, are described above. Fish and shellfish exposed to oil may become tainted which could prevent an entire catch from being sold (Clark, 2001). There is evidence that fish are able to detect and avoid oil-contaminated waters, therefore tainting is more a concern for immobile shellfish which cannot swim away. This is more common in filter feeding shellfish, such as scallops, as they could take up fine oil droplets from the water column. Very small quantities of crab are the only shellfish taken from the area around the proposed Cambo Field Development, and significant shellfish landings are confined to areas much further inshore (Section 4.6.1).

If fishing in the area of an oil spill, nets may become fouled with floating oil. This not only causes damage to the nets themselves but contact with fouled fishing gear may also contaminate subsequent catches. Fishing activity in the area immediately around the proposed Cambo Field Development is very low when compared with the shallower slope and shelf waters (Section 4.6.1; Marine Scotland, 2017).

The mixed demersal fisheries take the greatest proportion of fish landed from the continental shelf and shelf break, to the east of Cambo. These trawl fisheries operate year round and nets could potentially become tainted in the unlikely event of a large oil spill occurring. Major spills may also result in loss of fishing opportunities with boats unable or unwilling to fish due to the risk of fouling causing a temporary financial loss to commercial fishermen. Herring fisheries operate in more inshore locations around the Shetland and Orkney Islands.

Aquaculture

Numerous fish and shellfish farms are distributed across the Shetland and Faroe Islands (Section 4.6.2) and, therefore, aquaculture is an important contributor to the economies of these island groups. Tainting is of concern for all caged fish and shellfish farms as the animals are unable to swim away. If a large surface spill is allowed to reach these islands the many mariculture farms which cultivate fish and shellfish may be at risk from tainting and fouling, potentially leaving their stock unmarketable.

Although all oils can cause taint, lighter oils are generally more potent (Clark, 2001). Any large oil spill from the proposed Cambo Field Development would have undergone the weathering processes described above (Section 13.4.2) and, therefore, will have lost many of its lighter fractions by the time it reached the shore. Although this would not completely prevent the environmental impact of the oil with regard to tainting, it may limit the severity.

13.5.4 Potential for a Major Environmental Incident

The Offshore Safety Directive (2013/30/EU) came into force, via UK Regulations, on 19 July 2015. These Regulations require that a Safety Case defining Major Accident Hazards (MAH) with the potential to cause Major Accidents (MA) must be in place to cover all relevant offshore operations. The potential for MAs to cause a Major Environmental Incident (MEI) must also be defined in the Safety Case. For the proposed Development, two scenarios with the potential to cause a MEI have been identified (Section 13.1):

- Spillage of hydrocarbons in the event of an uncontrolled well blow-out;
- Rupture of crude oil storage tanks.

Therefore, these two scenarios have been used as the basis for the MEI Assessment.

MEI Assessment Methodology

The Offshore Safety Directive defines a MEI as an incident which results, or is likely to result, in significant adverse effects on the environment (Article 2[37]). Environmental vulnerability to oil spills is dependent on both the size of the spill and also the sensitivity of receptors. There is no standard quantitative method of determining the environmental impact likely to be associated with an oil spill, and so a qualitative approach based on the "Impact Scales and Gradation of Oil Spill Ecological Hazards and Consequences in the Marine Environments" classification guide by Patin (2004) has been used for this MEI assessment.

Table 13.6 shows the consequence assessment methodology defined by Patin (2004). These criteria have been used to consider the potential impact of a worst-case scenario oil spill from the proposed Development on UK protected sites, including Special Protection Areas (SPA), Special Areas of Conservation (SAC) and Nature Conservation Marine Protected Areas (NCMPA), which have been designated for the protection of habitats and species. Whilst the MEI Assessment is solely required to consider the impact to UK sites, it is acknowledged that the oil spill modelling results show potential for oil reaching the waters of the Faroe Islands, Iceland and Norway, and potential for oil beaching in Norway or the Faroe Islands. In the event of an incident that could impact the waters of an adjacent State, SPE would liaise with the relevant national authorities to assess the scale of any potential impacts.

Table 13.6: Consequence Assessment Methodology based on Patin (2004)

A. Spatial Scale (Area)	
Spatial Scale	**Area Under Impact**
Point	Less than 100 m^2
Local	Range from 100 m^2 to 1 km^2
Confined	Range from 1 km^2 to 100 km^2
Sub-regional	More than 100 km^2
Regional	Spread over shelf area

B. Temporal Scale	
Temporal Scale	Longevity
Short term	Several minutes to several days
Temporary	Several days to one season
Long-term	One season to 1 year
Chronic	More than 1 year

C. Reversibility of Changes	
Reversibility of Changes	Longevity of Disturbance
Reversible (acute stress)	Acute disturbances in the state of environment and stresses in biota that can be eliminated either naturally or artificially within a short time span (several days to one season)
Slightly reversible	Disturbances in the state of environment and stresses in biota that can be eliminated either naturally or artificially within a relatively short time span (one season to 3 years)
Irreversible (chronic stress)	Prolonged disturbances in the state of environment and stresses in biota that exist longer than 3 years

D. Consequence Assessment – General Assessment	
General Assessment	Disruption
Insignificant	Minimal changes that are either absent or not discernible.
Slight	Slight disturbances to the environment and short-term stresses in biota are discernible (below minimum reaction threshold 0.1% of natural population reaction).
Moderate	Moderate disturbances to the environment and stresses in biota are observed (changes up to 1% of natural population reaction are feasible).
Severe	Severe disturbances to the environment and stresses in biota are observed (up to 10% of natural population).
Catastrophic	Catastrophic disturbances to the environment and stresses in biota are observed (up to 50% of natural population). Changes are irreversible and stable structural and functional degradation of a system is evident.

Figure 13.12 details the maximum extent of surface and shoreline oiling. The oil spill modelling results show that the majority of crude oil would be expected to move to the northeast and east, with the coastlines of Shetland and Norway most likely to be affected, followed by the coastlines of the Orkney and Faroe Islands (Section 13.4.3). During spring and summer, in the case of the well blow out scenario, there is also a small probability of an oil slick reaching the north coasts of Scottish mainland or the Island of Lewis. Figure 13.12 shows the maximum extent of the area that may become oiled

over all four seasons which were modelled. Protected sites which overlap with the maximum potential extent of oiling are also shown in Figure ***13.12***.

Table 13.7 lists the protected sites that have been shown by the modelling to have the potential to be affected by a large oil spill from the proposed Cambo Field Development. As shown by the vertical plume modelling (Section 13.4.3; Figure 13.8), oil released from the seabed in the event of an uncontrolled well blow-out would be expected to quickly rise to the sea surface. Therefore, marine protected sites designated for the protection of deep-water benthic habitats (such as the North-East Faroe-Shetland Channel MPA and the Faroe-Shetland Channel Sponge Belt MPA) are not expected to be affected in the event of a spill from the proposed Development, and have not been included in Table 13.7 or in Figure 13.12.

The potential impact of surface or shoreline oiling on the habitats and species of the protected sites listed in Table 13.7 has been assessed. As an initial step in the assessment, thresholds have been applied in terms of the minimum arrival time and maximum probability of oiling to screen these protected sites in or out of the MEI assessment.

The modelling results provide a worst-case scenario with the assumption that there would be no intervention in the slick. In practice, oil spill response resources would be mobilised immediately if a spill occurred, and oil spill response efforts would prioritise the protection of sensitive habitats and species. Therefore, it is assumed that sites at which oil would be expected to take more than three weeks to reach, or with a probability of less than 5% for any oiling to occur, would be very unlikely to be subject to significant adverse effects and consequently can be screened out of the assessment. Therefore, these sites (Copinsay SPA; Noss Head NCMPA; North Caithness Cliffs SPA, East Caithness Cliffs NCMPA, SAC and SPA, Cape Wrath SPA, Hoy SPA and the Inner Hebrides and the Minches NCMPA) have not been considered further in this assessment. The remaining protected sites have been assessed according to the consequence assessment methodology detailed above.

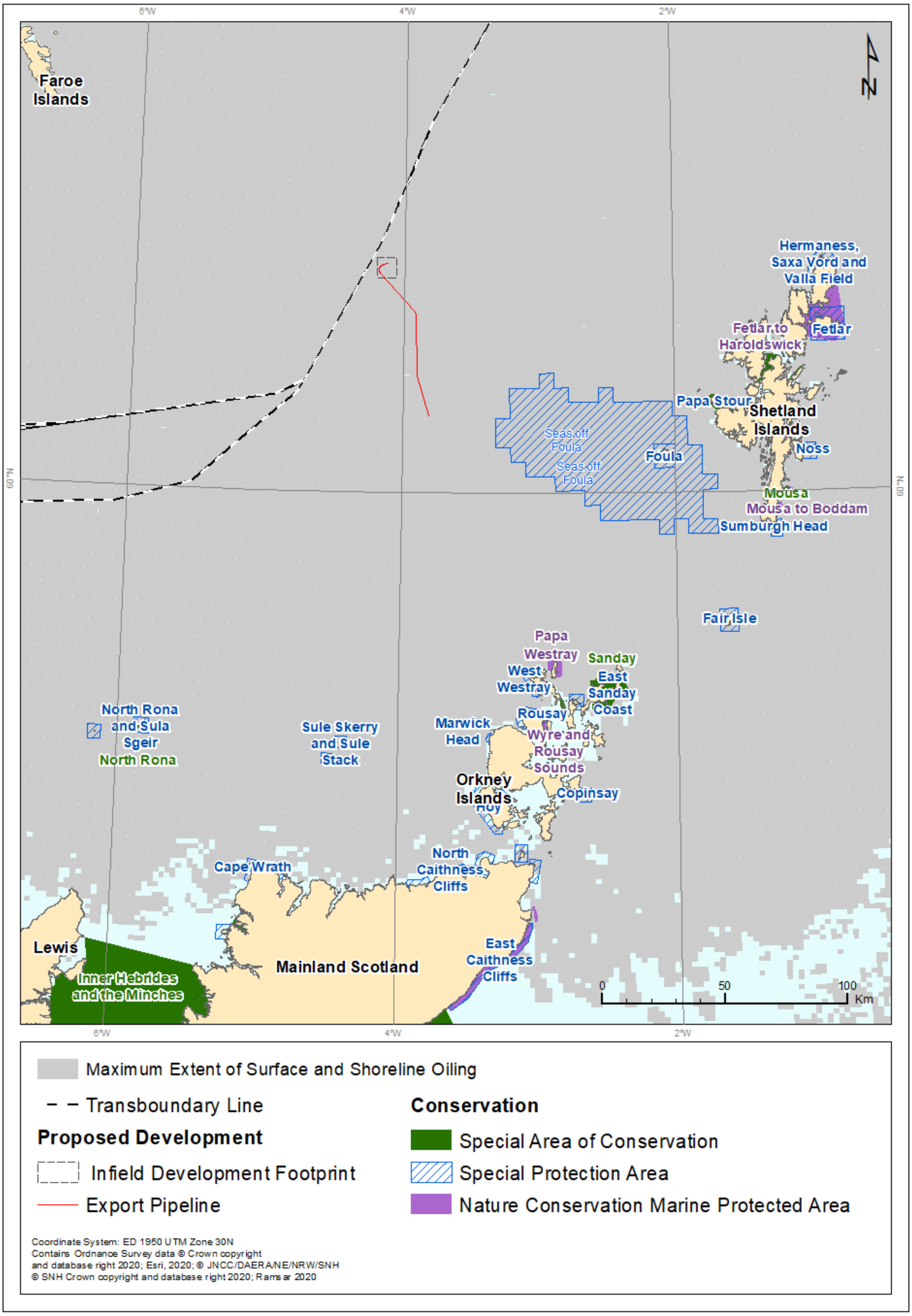

Figure 13.12: Maximum Potential Surface or Shoreline Oiling from an Uncontrolled Well Blow-out (a) or Crude Oil Storage Tank Rupture (b) overlain with Protected Sites

Source: OSRL, 2020a; OSRL, 2020b; SNH, 2020; JNCC, 2020.

Table 13.7: Protected Sites which may be Impacted by a Large Oil Spill from the Proposed Cambo Field Development

Name	Designation	Location	Well Blow Out		Complete loss of FPSO inventory		Qualifying Features (SAC: Only coastal habitats are listed; SPA: percentage bird populations listed refer to relevant biogeographic area for each species; MPA: Geodiversity Features not listed)
			Maximum Probability	Minimum Arrival Time	Maximum Probability	Minimum Arrival Time	
Hermaness, Saxa Vord and Valla Field	SPA	Coastal, Shetland	89.0%	7 Days 18 Hrs	49.0%	5 Days 3 Hrs	Breeding seabird assemblage and individual species of international importance (including at least 3% of red-throated diver, 4.6% of gannet, 4.6% of great skua and 2.8% of puffin)
Seas off Foula	pSPA	Offshore Shetland	80.5%	2 Days 12 Hrs	25%	3 Days 18 Hrs	Breeding seabird assemblage and individual species of international importance (including at least 5% of Great Skua), as well as migratory seabird assemblage during non-breeding season.
Fetlar to Haroldswick	NCMPA	Inshore, Shetland	60.0%	11 Days 0 Hrs	28.0%	8 Days 0 Hrs	Biodiversity: black guillemot; circalittoral sand and coarse sediment communities; horse mussel beds; kelp and seaweed communities on sublittoral sediment; maerl beds; shallow tide-swept coarse sands with burrowing bivalves
Fetlar	SPA	Coastal, Shetland	53.0%	11 Days 0 Hrs	25.0%	8 Days 0 Hrs	Breeding seabird assemblage and individual species of international importance (including at least 1.2% of Arctic tern, 75% of UK of red-necked phalarope, 0.8% of dunlin, 3.8% of great skua and <0.1% of whimbrel)
Foula	SPA	Coastal Shetland with marine component	42.0%	5 Days 0 Hrs	9.0%	5 Days 12 hrs	Breeding seabird assemblage and individual species of international importance (including at least 2.5 % of Arctic tern, 0.1% of Leach's storm petrel, 1.2% of red-throated diver, 16% of world population of Great Skua, 1.1% of guillemot, 5.3% of puffin and 1.9% of shag)
North Rona and Sula Sgeir	SPA	Coastal, off mainland Scotland	32.0%	9 Days 21 Hrs	5.0%	12 Days 9 Hrs	Breeding seabird assemblage and individual species of international importance (including at least 5.0% of Leach's storm petrel, 1.2% of

Name	Designation	Location	Well Blow Out		Complete loss of FPSO inventory		Qualifying Features (SAC: Only coastal habitats are listed; SPA: percentage bird populations listed refer to relevant biogeographic area for each species; MPA: Geodiversity Features not listed)
			Maximum Probability	Minimum Arrival Time	Maximum Probability	Minimum Arrival Time	
							storm petrel, 3.4% of gannet and 1.3% of guillemot)
Sumburgh Head	SPA	Coastal, Shetland	29.0%	13 Days 15 Hrs	3.0%	12 Days 15 Hrs	Breeding seabird assemblage and individual species of international importance
Noss	SPA	Coastal, Shetland	26.0%	18 Days 12 Hrs	4.0%	14 Days 6 Hrs	Breeding seabird assemblage and individual species of international importance (including at least 2.8% of gannet, 3.0% of great skua and 1.4% of guillemot)
Fair Isle	SAC	Coastal, Fair Isle	25.0%	11 Days 12 Hrs	5.0%	10 Days15 Hrs	Annex I Habitats: Vegetated sea cliffs of the Atlantic and Baltic coasts
Fair Isle	SPA	Coastal, Fair Isle	25.0%	11 Days 12 Hrs	5.0%	10 Day s15 Hrs	Breeding seabird assemblage of international importance and breeding species of European importance (including at least 2.5% of Arctic tern, 100% of Fair Isle wren and 1.1% of guillemot)
Papa Stour	SAC	Coastal, Shetland	22.0%	8 Days 3 Hrs	6.0%	7 Days 15 Hrs	Annex I habitats: reefs; submerged or partially submerged sea caves
Papa Stour	SPA	Coastal, Shetland	22.0%	8 Days 3 Hrs	6.0%	7 Days 15 Hrs	Individual species of international importance (including at least 2.3% of Arctic tern)
Sule Skerry and Sule Stack	SPA	Coastal, off Orkney	21.0%	12 Days 21 Hrs	1.0 < %	13 Days 9 Hrs	Breeding seabird assemblage and individual species of international importance (including at least 0.0% of Leach's storm petrel, 1.2% of storm petrel, 1.9% of gannet and 4.8% of puffin)
Mousa	SAC	Coastal, Shetland	18.0%	16 Days 12 Hrs	2.0%	16 Days 6 Hrs	Annex II species: common seal
North Rona	SAC	Coastal, off mainland Scotland	18.0%	10 Days 6 Hrs	2.0%	17 Days 18 Hrs	Annex II species: grey seal

Name	Designation	Location	Well Blow Out		Complete loss of FPSO inventory		Qualifying Features (SAC: Only coastal habitats are listed; SPA: percentage bird populations listed refer to relevant biogeographic area for each species; MPA: Geodiversity Features not listed)
			Maximum Probability	Minimum Arrival Time	Maximum Probability	Minimum Arrival Time	
Papa Westray	NCMPA	Coastal, Orkney	18.0%	10 Days 15 Hrs	3.0%	10 Days 15 Hrs	Black guillemot
Sanday	SAC	Coastal, Orkney	18.0%	11 Days 6 Hrs	3.0%	11 Days 12 Hrs	Annex I habitats: reefs. Annex II species: common seal
Calf of Eday	SPA	Coastal, Orkney	16.0%	12 Days 0 Hrs	3.0%	11 Days 3 Hrs	Breeding seabird assemblage of international importance
West Westray	SPA	Coastal with marine component, Orkney	14.0%	11 Days 12 Hrs	3.0%	12 Days 0 Hrs	Breeding seabird assemblage and individual species of international importance
North Caithness Cliffs	SPA	Coastal, mainland Scotland	12.0%	22 Days 18 Hrs	N/A	N/A	Breeding seabird assemblage and individual species of international importance (including at least 0.5% of peregrine falcon and 1.2% of guillemot)
Marwick Head	SPA	Coastal, Orkney	11.8%	14 Days	N/A	N/A	Breeding seabird assemblage and individual species of international importance (including at least 1.1% of world population of Great Skua)
Copinsay	SPA	Onshore, Orkney	11.0%	24 Days 6 Hrs	N/A	N/A	Breeding seabird assemblage of international importance
East Sanday Coast	SPA	Coastal, Orkney	8.0%	12 Days 6 Hrs	3.0%	11 Days 15 Hrs	Overwintering species of European importance
Rousay	SPA	Coastal, Orkney	8.0%	15 Days 12 Hrs	1.0 < %	14 Days 18 Hrs	Individual species of international importance (including at least 2.3% of Arctic tern)
Cape Wrath	SAC	Coastal, mainland Scotland	4.0%	15 Days 18 Hrs	N/A	N/A	Annex I Habitats: Vegetated sea cliffs of the Atlantic and Baltic coasts
Cape Wrath	SPA	Coastal, mainland Scotland	4.0%	15 Days 9 Hrs	N/A	N/A	Breeding seabird assemblage of international importance
Hoy	SAC	Coastal, Orkney	3.0%	19 Days 18 Hrs	N/A	N/A	Annex I Habitats: vegetated sea cliffs of the Atlantic and Baltic coasts

Name	Designation	Location	Well Blow Out		Complete loss of FPSO inventory		Qualifying Features (SAC: Only coastal habitats are listed; SPA: percentage bird populations listed refer to relevant biogeographic area for each species; MPA: Geodiversity Features not listed)
			Maximum Probability	Minimum Arrival Time	Maximum Probability	Minimum Arrival Time	
Hoy	SPA	Coastal, Orkney	3.0%	19 Days 18 Hrs	N/A	N/A	Breeding seabird assemblage and individual species of international importance (including at least 0.5% of peregrine falcon, 6.0% of red-throated diver and 14.0% of great skua)
Noss Head	NCMPA	Coastal, mainland Scotland	2.1%	32 Days 12 Hrs	N/A	N/A	Biodiversity: horse mussel beds
East Caithness Cliffs	SAC	Coastal, mainland Scotland	0.7%	33 Days 0 Hrs	N/A	N/A	Annex I Habitats: vegetated sea cliffs of the Atlantic and Baltic coasts
East Caithness Cliffs	SPA	Coastal, mainland Scotland	0.7%	33 Days 0 Hrs	N/A	N/A	Breeding seabird assemblage and individual species of international importance (including at least 0.5% of peregrine falcon, 3.2% of guillemot, 1% of herring gull and kittiwake, 1.6% of razorbill and 1.9% of shag)
East Caithness Cliffs	NCMPA	Coastal, mainland Scotland	0.7%	33 Days 0 Hrs	N/A	N/A	Biodiversity: Black guillemot
Inner Hebrides and the Minches	SAC	Marine, off mainland Scotland	0.7%	22 Days 18 Hrs	N/A	N/A	Annex II species: harbour porpoise

Source: OSRL, 2020a; OSRL 2020b; SNH, 2020; JNCC, 2020.

Sea Surface Oiling

Section 13.5.1 describes the sensitivities of birds on the sea surface to oiling, and Figure 13.11 demonstrates that at certain times of year there is potential for high densities of birds to be present on the sea surface in the wider vicinity of the proposed Development. Seventeen of the protected sites listed in Table 13.7 are SPAs designated for the protection of birds listed under Annex I of the Birds Directive, whilst one (Seas Off Foula) is a proposed SPA currently under consultation. Two NCMPAs are also designated for the black guillemot. The majority of these sites are designated for the assemblage of birds that they support, and some are additionally designated for supporting a significant proportion of the population of certain species. It would be very unlikely for a spill to affect all of these sites, and so it would be expected that in the event of an oil spill affecting one of the sites, population recruitment would occur from other neighbouring sites by the following breeding season. The Fair Isle SPA supports 100% of the breeding population of Fair Isle wren, and so this species would not be able to recruit from neighbouring populations. However, this species forages inland and would therefore not be expected to be impacted by an oil spill.

Marine mammals may also be sensitive to sea surface oiling, as discussed in Section 13.5.1. The Sanday and Mousa SACs, listed in Table 13.7, are both designated for the protection of common seals, whilst the North Rona SAC is designated for grey seals. However, marine mammals are known to be able to avoid surface oiling. Therefore, given the temporary nature of an oil spill to surface, it would not be expected that marine mammals would suffer a significant adverse effect.

Using the environmental consequence assessment

Table **13.6** (Patin, 2004), the assessment of this scenario is summarised in Table 13.8.

Table 13.8: Environmental Consequence Assessment for Sea Surface Oiling

Scale	Assessment	Justification
Spatial	Sub-regional	Maximum extent of spill as shown in Figure 13.12
Temporal	Long-term	Expected recovery by the following breeding season, in around one year
Reversibility	Reversible	The disturbance to the environment would be removed within one year
General	Moderate	Change expected in no more than 1% of the population

In summary, although potential for recovery would be good, surface oil contamination has the potential to cause a measurable significant adverse effect to protected bird species. Therefore, there is the potential for a MEI to occur as a result of sea surface oiling at the following protected sites:

- SPAs: Sumburgh Head; West Westray; Fetlar; Foula; Hermaness, Saxa Vord and Valla Field; Sule Skerry and Sule Stack; Marwick Head; Noss; North Rona and Sula Sgeir; Calf of Eday; Fair Isle; Papa Stour; Rousay; and East Sanday Coast.
- pSPA: Seas off Foula.
- NCMPAs: Fetlar to Haroldswick; and Papa Westray.

Shoreline Oiling

A number of the SACs listed in Table 13.7 have been designated for the protection of coastal or shallow water habitats. These habitats include reefs (Sanday and Papa Stour), submerged or partially submerged sea caves (Papa Stour) and vegetated sea cliffs of the Atlantic and Baltic coasts (Cape Wrath, Fair Isle and Hoy). Additionally, the Fetlar to Haroldswick NCMPA has been designated for circalittoral sand and coarse sediment communities; horse mussel beds; kelp and seaweed communities on sublittoral sediment; maerl beds; and shallow tide-swept coarse sands with burrowing bivalves. These habitats have varying vulnerability to oiling.

As previously discussed, deeper water benthic habitats are not expected to be affected by oiling. Therefore, reefs, submerged sea cliffs, horse mussel and maerl beds would not be expected to be subject to significant adverse effect.

As discussed in Section 13.5.1, rocky shores are high energy environments which generally have the ability to recover quickly in the event of oiling. Partially submerged sea caves would therefore not be expected to be a vulnerable habitat. Exposure to the sea is a key determinant for which vegetated sea cliff habitats are designated, and this habitat is found in the spray zone of high energy cliffs. However, this small amount of exposure to sea water means that the potential for oil to cause significant adverse effect to this habitat is minimal.

Circalittoral sand and coarse sediment communities; kelp and seaweed communities on sublittoral sediment; and shallow tide-swept coarse sands with burrowing bivalves are all comprised of softer sediments in the tidal zone, which tend to be more vulnerable to the effects of oil spills (Section 13.5.1). This lower energy environment is also likely to take a longer time to recover in the event of significant adverse effect.

The SPAs (and NCMPAS designated for black guillemot) listed in Table 13.7 are considered less vulnerable to shoreline oiling. Breeding and overwintering sites used by birds tend to be on the upper stretches of cliffs or on grassy slopes beyond the high water mark, and so shoreline oiling is likely to have less of an impact on birds than that on the sea surface.

Using the environmental consequence assessment

Table **13.6** (Patin, 2004), the assessment of this scenario is summarised in Table 13.9.

Table 13.9: Environmental Consequence Assessment for Shoreline Oiling

Scale	Assessment	Justification
Spatial	Sub-regional	Maximum extent of spill as shown in Figure 13.12
Temporal	Chronic	Expected recovery to soft sediment habitats to take more than one year
Reversibility	Slightly reversible	The disturbance to the environment would take longer than one year to be removed from soft sediment environments
General	Moderate	Change expected in no more than 1% of the population.

In summary, shoreline oil contamination has the potential to cause a measurable significant adverse effect to protected sedimentary shores. Therefore, there is the potential for a MEI to occur as a result of shoreline oiling at the Fetlar to Haroldswick NCMPA.

Conclusion

The MEI assessment shows that a large oil spill from either an uncontrolled well blow out or the complete loss of the maximum FPSO inventory at the Cambo Field Development will have the potential to cause a significant adverse effect to up to 17 SPAs, 1 pSPA and 3 NCMPAs due to oil on the sea surface, and to 1 NCMPA as a result of shoreline oiling. It should be noted however, that this assessment is based on stochastic modelling results. Stochastic modelling results are not representative of the effects of a single spill event, but illustrate the potential total geographic range of any oil spill event, based on hundreds of individual spill scenarios using a wide variety of metocean conditions. In the event of an actual oil spill, the affected area(s) will be much more localised, and will depend on the volume of oil spilled and local metocean conditions at the time.

13.6 Mitigation Measures

13.6.1 Preventative Measures

In order to prevent an oil spill occurring, stringent safety and operational procedures will be followed at all times.

Training, Experience and Suitability of Equipment

SPE, the Installation Operator for the FPSO and the Well Operator will be aware of the risk of a hydrocarbon spill at the proposed Cambo Field Development. Before offshore operations commence, the Installation/Well Operator will fully assess the competence and experience of all contractors, and the suitability of all equipment to operate in the West of Shetland area. All offshore personnel will be appropriately trained, experienced and certified to carry out their specific duties. The crew of the FPSO and the MODU will also undergo environmental awareness and safety training.

Well Design

The Cambo wells have been designed to minimise the potential for well control problems.

A thorough and formal peer-review approach will be used to review all critical elements of the well designs and the execution of drilling and abandoning the well. In addition, the well designs will be independently reviewed by a Well Examiner, as is required for all wells in the UK. The Well Examiner will also monitor the actual construction and any modifications to the wells.

Any change or deviation to the drilling programme, the subsurface parameters for the well design, or the well construction itself, will be subject to a formal management of change process. The purpose of this process is to identify, assess and document any changes prior to them being made. Each change requires management approval.

Well Control

Well control procedures will be in place, to prevent uncontrolled well flow to the surface and a full risk assessment will be performed as part of the planning phase of each well. Data on well pressure will be monitored throughout the drilling operations, to allow suitable mud composition and mud weights to be used.

A blow-out preventer (BOP) will be put in place once the 17½" section has been drilled and 20" × 13⅜" casing run in order to prevent the uncontrolled release of hydrocarbons from the well. The BOP stack and associated well control equipment on the MODU will be all rated to at least 15,000 psi working pressure. The BOP will be fully redundant, which means it can be operated independently from two physically separated locations onboard the MODU. In addition to the standard control systems, the BOP typically has several other backup emergency control systems, namely:

- Emergency Disconnect System (EDS). A single activation button closes the shear rams (large valves) on the BOP, followed by Choke and Kill line fail safe valves. The control system then automatically unlatches the top section of the BOP, i.e. the Lower Marine Riser Package (LMRP), from the main BOP;
- Autoshear System. In the event of an unplanned unlatch of the LMRP from the BOP, a pre-selected series of BOP rams shut and will close off the well;
- Acoustic Control System. Remote activation of the BOP via acoustic transponders can be used to operate a number of the BOP functions to make the well safe;
- Remotely Operated Vehicle (ROV) Intervention Panel. Numerous functions on the BOP can be operated by an ROV either by manual valve operation or stabbing into the BOP and using a pump on the ROV;
- Automatic Mode Function (AMF). On total loss of electric controls and hydraulic supplies, the BOP shear rams close automatically by means of a dedicated accumulator supply.

The BOP will be independently inspected and verified periodically. Regular testing of the BOP and its back up systems takes place onboard the MODU, typically at 7 and 21 day intervals.

Diesel/Fuel Oil Bunkering and Crude Oil Tanker Offloading Procedures

The highest risk of spillages occurs during bunkering operations between the FPSO/MODU and supply vessels and during transferring crude oil from the FPSO to the shuttle tanker. Vessel audits will be performed to confirm sea worthiness of supply vessels and shuttle tankers, and only DP vessels will be used, thus reducing likelihood of collision and potential tank rupturing. Bunkering and offloading operations will only take place during hours of good visibility, in suitable weather conditions, and with a dedicated and continuous watch posted at both ends of the fuel/offloading hose. All hoses used during bunkering/offloading will be segmented with pressure valves that will close automatically in the event of a drop in pressure, such as might be caused by a broken connection or a leaking hose. In addition, the bunkering/offloading hoses will be stored on reels, to prevent wear and damage. These hoses will be visually inspected and their connections tested prior to every loading operation. Bunkering/offloading procedures will be followed throughout all bunkering/offloading operations.

FPSO Design

The loss of crude oil from one or all of the cargo storage tanks onboard the FPSO is extremely unlikely and would only be expected to occur during a major collision with another vessel or as a result of a natural disaster or similar event, whereby the integrity of the FPSO itself would be compromised. The FPSO will be designed with double bottom/doubled-sided hull. In addition, the cargo tanks will be configured with ballast tanks on the outside, offering protection from cargo tanks and reduced probability of loss. Section 13.8, on the potential impacts in case of catastrophic loss of the FPSO, describes further mitigation measures in place to prevent a serious collision event from happening.

Other Safety Measures

All equipment used on the FPSO and the MODU will have safety measures built in to minimise the risks of any hydrocarbon spillage. For example, the FPSO and the MODU will have open and closed drain systems in place that will route any operational spills onboard the FPSO or MODU to the slop tanks where they can be contained and recovered. There are also a number of spill kits available to deal with (smaller) spillages. All supply vessels will operate via DP, in order to reduce likelihood of collision and therefore potential tank rupturing.

13.6.2 Action to Stop a Subsea Spill During Drilling with the MODU

Initial Actions

The initial response to a subsea spill will be to use the ROV to identify the source of the leak. However, if at any time the safety of the MODU becomes compromised, the first priority will be to close the BOP, disconnect the MODU from the well, and move off location. While the BOP is designed as fail safe closed, ROV and acoustic overrides are available should this not work correctly. This will allow the BOP to be closed within 24 hours, even if the MODU has to move off location first. Once at a safe distance from the well location, the ROV can be deployed to verify the BOP is properly closed, and no more oil is being spilled.

In a situation where the MODU is not disconnected from the well, and depending on when in the programme of operations a blow-out occurs, there may be various other methods available to control the flow of hydrocarbons to the surface. These include varying the pump rate and the use of various chemicals, such as weighting material (barite or calcium carbonate) and cement. Therefore, a contingency stock of cement and barite will be kept onboard the MODU. Although the time required to kill the well will be dependent on the how and why it has failed, a standard well kill operation takes between 12 and 48 hours. Once control of the well has been regained, the well can be fully abandoned with cement plugs.

Capping the Well

In the event of a subsea blow-out, whereby the BOP has failed and oil is freely flowing into the sea, the possibility of fitting a temporary capping device to the well will be considered. Once installed, this type of cap will completely seal off the well and stop oil from spilling into the sea whilst a relief well is drilled, and the original well is killed. This is currently regarded as the most likely successful approach to containing an uncontrolled subsea blow-out.

SPE is a member of Oil Spill Response Ltd (OSRL), which allows SPE access to the OSPRAG (the Oil Spill Prevention and Response Advisory Group) Capping Device. The OSPRAG well capping device is of a modular design which will allow installation at various points of the subsea wellhead or the blow-out preventer (BOP). SPE has reviewed the technical specifications of the cap and has confirmed that it is compatible with the subsea equipment proposed for use at Cambo. The Cambo wells all fall within the maximum technical specifications for well flow rate, pressure and temperature, confirming that this device is suitable for use. This capping device would be SPE's primary option for sealing the well, if required.

At approximately 40 tonnes, the capping device is suitable for installation by a light intervention vessel. In the event that it is required, the device would be transported from Aberdeen to the Cambo Field, for deployment from a light well intervention vessel. Although no contract is in place for such a vessel, the type of vessel required to install the cap is relatively easy to procure and deploy. SPE is confident that a suitable vessel would be able to be procured at very short notice.

In the event of an uncontrolled well blow-out, it is anticipated that it would take a total of 30 days until the capping device could be deployed and the well contained. This timeframe would include sourcing of an appropriate vessel, mobilisation of the capping device to the Cambo Field, site preparation and clearance at the well location, deployment of the capping device and well containment. A full timetable for this procedure will be provided in the Well Operator's Temporary Operations Oil Pollution Emergency Plan (TOOPEP) covering the drilling operations at Cambo operations.

Drilling a Relief Well

In the extremely unlikely event where a blow-out situation occurred and all options to kill the well failed, the only remaining option to bring the well back under control to stop the spill may be to drill a relief well. This would also apply as the required operation to permanently close the well once the well capping device (described above) was fitted. In this situation, SPE and the Well Operator will comply with the Oil and Gas UK "Guidelines on Relief Well Planning – Subsea Wells" (currently Issue 2, January 2013) which has been prepared by the OGUK Well Life Cycle Practices Forum.

Securing Required Equipment

As a worst-case scenario, it is assumed that an additional suitable MODU, would be required to conduct the relief well operations. The harsh conditions in the West of Shetland environment, and the deep-water at the proposed well locations, limits the number of MODUs which are technically capable of drilling in this geographic area. Therefore, an assessment of the suitability of available MODUs will be undertaken and the availability of these rigs will continue to be monitored throughout the drilling operations at Cambo. It has been estimated that it would take between four and six weeks to source an alternative suitable drilling unit, for the current operations to be suspended, and to move the unit onto the well location.

In addition to the drilling unit, all of the required drilling equipment will also have to be sourced and mobilised. In order to minimise the time involved, equipment would be sourced from off the shelf supplies and borrowed from other operators. Throughout this planning and preparation process, it is assumed that other license holders, drilling rig contractors and the government agencies would co-operate where necessary.

Planning for the relief well will include a review of the original well design and the reasons for the uncontrolled well blow-out, allowing any required changes to well design, equipment and operating procedures to be implemented. Preparation of equipment, procedures and consent applications will all be conducted in parallel with the activities required to gain access to a suitable replacement drilling unit.

Drilling the Relief Well

Several alternative relief well locations around the Cambo Field will be identified in the Relief Well Plan. All of these locations will be covered by digital site survey lines, enabling shallow gas and drilling hazard studies to be carried out within 5 days of the best relief well site being selected. A well path will be created to ensure that the suggested well surface locations are suitable and can be quickly tailored to the actual relief well programme if required in a blow-out situation. In order to optimise the relief well design, planning at the time of an incident will include a review of the current location and directional plans, along with the reasons for well failure and the resultant uncontrolled blow-out. This will allow any required changes to be made to relief well design and equipment, and additional operating procedures to be implemented if required.

Once a suitable MODU has been sourced and mobilised to location (expected to take four to six weeks, as stated above), and a relief well design selected, is anticipated that it would then take approximately 50 days to drill a relief well and kill the original well. Once the relief well reaches the original well, well kill operations would be carried out to permanently abandon it.

13.6.3 Oil Spill Response

If a large well control incident were to occur, it would be a priority to avoid spilled hydrocarbons impacting the coastline and, therefore, all available and suitable oil spill response techniques would be employed in the event of a spillage moving towards the shore.

Oil Pollution Emergency Plan

The FPSO's Installation Operator and the MODU's Well Operator will have an OPEP/TOOPEP in place, respectively. The OPEP/TOOPEP will conform to the Merchant Shipping (Oil Pollution, Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 and the Offshore Installations (Emergency Pollution Control) Regulations 2002. The OPEP/TOOPEP will fully consider the specific oil spill response requirements for Cambo, taking into account the location, the prevailing meteorological conditions and the environmental sensitivities of the area. The plans will be designed to assist the decision-making process during a hydrocarbon spill, indicate what resources are required to combat the spill, minimise any further discharges and mitigate its effects.

Training, Exercises and Experience

Offshore Personnel

Specific members of the FPSO/MODU and standby vessel crew will have undertaken Oil Pollution Emergency Plan (OPEP) level oil spill response training. The Offshore Installation Manager (OIM) and the Installation/Well Operator offshore representatives will have undertaken the OPRED course for On-Scene Commander (OPEP Level 1).

As a minimum, the OPEP/TOOPEP will be distributed to personnel with designated duties in the event that an oil spill response is required, and to the regulatory authorities and statutory consultees. On receipt of the OPEP/TOOPEP, personnel will undergo awareness training in oil spill response prior to the commencement of drilling operations. The aim of this training is to familiarise offshore personnel with the Well Operator's oil spill procedures, levels of response effort, equipment orientation and use, and communication and reporting during an oil spill of any size.

The FPSO and MODU will regularly undertake training exercises, including vessel-based oil spill response exercises for the crew and an Offshore TOOPEP Exercise while on site, to ensure that offshore personnel are familiar with the TOOPEP and their responsibilities during a response. Similar offshore exercises will be held periodically for the FPSO's OPEP, once it is in operation.

Onshore Personnel

External oil spill response training will be organised for key onshore personnel, in line with the OPRED requirements and the internal requirements of environmental training and continual improvement in the Well Operator's Management Systems. Relevant SPE and Installation/Well Operator Duty Managers will, as a minimum, have undertaken the OPRED course, Corporate Management oil spill response awareness (OPEP Level 2). SPE is a member of Oil Spill Response Ltd (OSRL), with activation rights being provided to the Installation/Well Operator. A response advisor with OPEP Level 4 training would also be provided by OSRL.

Desktop exercises will be undertaken prior to commencement of operations to test the effectiveness of the oil pollution emergency plan. The Installation/Well Operator will conduct these oil spill response exercises to ensure that all personnel are aware of their roles in an actual oil spill incident. The exercises will also familiarise personnel with the lines of communication between the FPSO/MODU, offshore, the Installation/Well Operator onshore and SPE. The exercises will also include familiarisation of the roles and responsibilities of the various interested parties, and the chosen response strategies. If necessary, the OPEP/TOOPEP will be updated to reflect any changes required as a result of these exercises.

13.6.4 Oil Spill Response Strategies

The most appropriate response to a hydrocarbon spill from the planned drilling operations will be determined by oil type, logistics and prevailing physical conditions. A precise response strategy, which may employ one or more of the response options described below, can only be decided at the time of the spill. Oil spill response personnel must be prepared to adapt their actions as the spill develops as changes in both the prevailing conditions and the oil properties dictate.

In general, there are several response strategies which could be deployed in the event of an oil spill:

- Natural dispersion and monitoring;
- Application of chemical dispersants;
- Containment and recovery (surface and subsea);
- Shoreline protection and clean-up.

Natural Dispersion and Monitoring

Small to medium crude spill and diesel spills of all sizes are often best monitored but otherwise left to naturally degrade, if spilled offshore far away from any coastline. The natural evaporation and dispersion processes described in Section 13.4.2 will often be enough to successfully disperse the crude or diesel. These processes can be enhanced, where practicable, by physical agitation of the slick by the standby vessel and other vessels on site.

It is proposed that, in the event of a crude or diesel spill incident, the principal response strategy will be the monitoring and surveillance of the slick, where evaporation and natural dispersion will be the principle mechanisms for removal of oil from the sea surface.

On-site and Aerial Surveillance

A standby vessel will be on site at all times during drilling and production operations through the life of the proposed Development. In the early stages of an incident, the slick may be monitored by this onsite standby vessel, provided it can still meet its safety function. For larger, ongoing spills, aircraft may be mobilised to undertake aerial surveillance. However, in the short term, aerial surveillance may be undertaken by the helicopter contractor.

A contract with OSRL will be put in place, allowing the rapid deployment of a dedicated aerial surveillance aircraft. The use of aerial surveillance in the monitoring of oil spills, as opposed to sea level vessels, allows for a more accurate picture of spill size and movement to be formed, especially in the monitoring of larger, more mobile spills. This would enable the development of various response options, including the decision to monitor the spill as it disperses naturally.

Oil Spill Modelling

Tracking and monitoring of the spilled oil would commence as soon as possible after the incident has occurred and continue for the duration of the response. This will be used to evaluate the extent of the slick, monitor its movement and dispersal, and decide on the appropriate response.

Initially, manual predictions can be used to estimate the movement of the oil on the sea surface as a function of the wind and current speed and direction. Oil spill modelling would also be employed to gain a more accurate indication of oil spill movement, using real time parameters to assist the predictions.

Chemical Dispersants

To aid natural dispersion of a large oil spill, or when sensitive receptors such as flocks of seabirds are at risk, SPE will consider applying chemical dispersants. As a member of ORSL, SPE will have access to the UK Dispersant Stockpile. The use of chemical dispersants has been found to be effective when sprayed onto fresh oil in moderate sea states, which are often present in the Cambo area. However, chemicals dispersants are ineffective on emulsified or weathered oils spills. Before use, the effectiveness of the available dispersant must always be tested on an actual sample of the spilled oil before using dispersants on the slick itself.

The use of chemical dispersants may therefore be considered for oil spills which are observed to not disperse naturally, in order to protect vulnerable concentrations of seabirds at sea or to prevent the oil slick from reaching a sensitive coastline. Dispersants can be sprayed directly onto floating oil as a fine mist, either from aircraft or boats. Large slicks can be treated quickly, deterring the formation of emulsions and accelerating the biodegradation of oil in the water column.

The natural processes of evaporation and dispersion will usually remove the lighter fractions from the spilled oil rapidly, without the need for chemical treatment. Dispersants are generally less effective on light oils, such as diesel, as the dispersants sink through the oil, reducing the contact time between the oil and water interface. As a result, chemical dispersants should generally not be used on these spilled light oils.

The use of chemical dispersants will result in increased concentrations of toxic components within the upper water column. Many spawning species have pelagic eggs and larvae which are vulnerable to oil which is chemically dispersed into the water column. These eggs and larvae may become exposed to higher concentrations of oil if dispersants were used, than if the oil had been allowed to evaporate and disperse naturally.

Therefore, the decision to use chemical dispersants will always need to consider its positive benefits against any resulting impacts in the water column.

Containment and Recovery

Booms may be used to contain a large slick on the sea surface, concentrating the oil for recovery by skimmers. The effectiveness of both booms and skimmers depends on the sea and weather conditions, with the most efficient containment and recovery of oil only achieved under calm conditions. In order to create a barrier with which to prevent the oil escaping, booms must move with the surface water. However, with the increasing flexibility required to achieve this in rougher seas, comes reduced boom rigidity and a corresponding reduction in its ability to contain oil. As skimmers float on the sea surface, they also experience many of the operational difficulties that apply to booms. The increased wind and water movement experienced in the West of Shetland offshore environment suggests that surface containment and recovery equipment are unlikely to be effective on a spill at the proposed Development.

Recovery equipment requires the spilled oil to be of sufficient thickness to allow it to be lifted and sucked from the surface while disturbing the underlying water as little as possible. If the slick is too thin large quantities of water will be taken up by the process not only reducing the effectiveness of oil collection, but also causing additional issues for containment and disposal of the oily water. As the slick becomes increasingly spread out and broken up, the effectiveness of this response option decreases.

Shoreline Protection and Clean-up

Shoreline Protection

Where possible, the first priority should be to prevent spilled hydrocarbons from reaching coastal areas. As described above, a number of different response options are available to contain the spilled oil offshore or to limit the movement of the slick across the sea surface. However, there remains the potential for a large slick to threaten the shoreline communities.

The initial response to any spill will be onsite and aerial surveillance to track its movement, supplemented by modelling to predict which shorelines the spilled oil may threaten. With a better understanding of the shorelines at risk from the spill, information will be gathered on the coastal habitats present in these areas and their associated communities. Any coastal sensitivities, including vulnerable shoreline types, coastal and inshore protected areas (including those designated under the European Habitats and Birds Directives), areas of inshore fisheries or aquaculture, coastal tourist or recreational areas, and other coastal industries, will be identified. Throughout the well planning process, basic information has been gathered on the surrounding coastal sensitivities and this will be included within the TOOPEP during drilling and subsequent OPEP during the production phase to assist in any required oil spill response. This will be supplemented by the OSRL Geographical Information System (GIS) facility (which maps coastal sensitivities around the UK), local authority plans, strategy documents, maps, and other available resources. The closest coastlines to the proposed Cambo Field Development are those associated with the Shetland Islands; the Shetland Oil Terminal Environmental Advisory Group (SOTEAG) has produced shoreline sensitivity maps for the Shetland coastline. Broad-scale surveys, from vehicles, inshore vessels or helicopters, will be mobilised to gain an overview of the shoreline types and main sensitivities along the potentially affected stretch of coast, and consideration will be given to carrying out more detailed surveys of particularly environmentally sensitive or commercial important areas of shoreline prior to any oil beaching.

Once the coastal sensitivities under immediate threat have been identified, coastal protection resources will be deployed to protect priority areas. Although SPE and the Installation/Well Operator will provide all necessary assistance as required, all shoreline protection strategies will be determined by the local authority in consultation with their environmental advisors. Details of local equipment suitable and available for shoreline booming will be available through coastal strategy documents. Additional response personnel and appropriate shoreline protection equipment will be provided by SPE and the Installation/Well Operator, through their oil spill response contractor, OSRL.

Oil spill modelling has indicated that the coastlines of Norway, the Faroe Islands and the Shetland Islands are under the greatest threat from beaching of crude oil (Section 13.4.3). These high energy coastlines are characterised by sea cliffs with little or no intertidal zone or exposed rocky shores consisting of bedrock platforms and boulders. Although oil may persist on more sheltered shores for longer, wave action may start to remove the oil from more exposed rocky shores more rapidly. With the dominance of exposed, vertical cliffs, it could be assumed that these northerly rocky shores would recover relatively quickly from a beaching oil spill, with minimum requirement for human intervention. These shores will also be the most difficult to protect with booms, due to access issues and the size of the approaching waves. As a result, priority is likely to be given to the more sensitive muddy shores and the large voes which hold fish and shellfish farms.

Shoreline Clean-up

Every effort will be made to clean-up up any oil that reaches the shoreline. Depending on the type of coastline affected, various methods exist to remove oil from the shore. Sediment shores are generally more amenable to methods that will physically ‘scoop’ the oil from the beach, whereas appropriate washing and rinsing techniques are likely to be more effective on rocky substrata.

If a spill does reach the shoreline, aerial surveillance will be used to gain a broad overview of where it has beached, while vehicles or vessels will be used to make a more detailed, shore specific assessment. Through OSRL, stretches of shoreline will be surveyed, recording the type of shoreline (sediment type, slope, exposure etc), its use (tourism, recreation, etc), and any environmental sensitivities (protected areas, seal breeding sites, otter holts, etc), as well as the severity of any oiling (mobile oil, surface or subsurface oil, stranded oil, sheen etc). Information on access arrangements, parking and storage arrangements, and proximity to other facilities will also be recorded. This information will be used to determine where to focus the clean-up effort by making the optimum use of the available clean-up resources.

In certain instances, the physical disturbances caused by some clean-up methods may be more damaging to shorelines and their associated communities than the direct effects of an oil spill. This is particularly true in more sensitive, less dynamic habitats, such as mudflats or saltmarsh. In addition, steeply sloping and unstable rocky shores or large soft mudflats are often difficult to access. Therefore, if oil does reach the shore, clean-up methods should be chosen carefully so as to not cause a greater degree of damage.

With all required assistance and information provided by SPE and the Installation/Well Operator, the strategy for shoreline clean-up ultimately will be directed by the affected local authorities. Adequately trained personnel and clean-up equipment will be made available to assist any clean-up operations, through OSRL.

13.6.5 Liability and Insurance

SPE will ensure that it has sufficient finances and insurance in place to cover the cost of responding to a large oil spill (including the use of a well capping device and drilling a relief well, if required). SPE is a member of the Offshore Pollution Liability Association Limited (OPOL). OPOL is a voluntary oil pollution compensation scheme to which all offshore operators currently active on the UKCS are party to. OPOL is accepted as representing the committed response of the oil industry in dealing with compensation claims arising from offshore oil pollution incidents from exploration and production facilities. At present the OPOL Limit of Liability is US $250 million per incident. Based on a recent oil spill modelling study undertaken on behalf of the Oil Spill Prevention and Response Advisory Group (OSPRAG), the current occurrence limit should be sufficient to cover the third party pollution compensation and remediation costs associated with the majority of spill scenarios, with only a small number of wells having the potential to exceed the OPOL Limit (OGUK, 2018).

While OPOL provides for third party clean-up and compensation costs to a predetermined limit, there may be additional extra expenses that the SPE as the Licence Operator may have to cover in the event of a blow-out, such as those related to bringing the well back under control and drilling a relief well. SPE will ensure that sufficient finance or insurance/indemnity provision is available to cover the drilling of relief wells.

13.7 Conclusions

The risk of a large-scale hydrocarbon spill during drilling operations or during the subsequent production phase of the proposed Cambo Field Development is very low. Historic spill data shows that large (crude) oil spills from oil and gas installations are very rare on the UKCS, and the overall volume spilled each year continues to reduce gradually over time. There has never been an oil spill as a result of a well blow-out on the UKCS. The largest oil spills (>25 tonnes) from MODUs were related to OBM discharges, with only 2 recorded crude oil spills of this size during the period 1990-2019. OBMs will not be used during the proposed Cambo wells, removing the risk of this type of spill. Similarly, large oil spills from FPSOs are also very rare, with only 9 spills over 25 tonnes from a total of 689 spills from FPSOs in the period 1990-2019.

The oil spill modelling scenario shows that a large spill, such as from a well blow-out or a complete loss of inventory from the Sevan FPSO, would, under the majority of meteorological circumstances, drift northeast of the proposed well location. A large oil spill would have the potential to reach the coasts of Shetland, Orkney, Faroe Islands or Norway, and during spring and summer time there would be a small probability of oil beaching on the north coast of mainland Scotland and the Isle of Lewis as well. These conclusions are based on modelling results that assume no intervention in the slick. In practice oil spill response resources would be mobilised immediately if a spill occurred. It would be a priority for SPE and the Installation/Well Operator to attempt to ensure no spilled oil would impact the coastline and, therefore, all appropriate oil spill response techniques would be employed in the event of a spillage moving towards the shore.

It should be noted that these potential impacts would only occur under extreme circumstances in the event of a very large oil spill, as modelled in this ES. Historic data on oil spills from oil and gas installation operating on the UKCS show that there has only been one crude oil spill of such a large size (112 tonnes) in the period 1990 to 2019. This spill happened in 1990. Historic data suggest small spills of less than 1 tonne represent the most likely spill scenarios.

Throughout the life of field, the focus will be on the prevention of oil spills. Stringent safety and operational procedures will be adhered to throughout the operations. A robust well design has been developed to minimise the potential for well control issues, and all critical elements of this design and the execution operations have been both peer and independently reviewed.

The Installation/Well Operator will have a detailed operation specific OPEP/TOOPEP in place to ensure that immediate and appropriate action is taken in the event of any hydrocarbon spillage, minimising any impact to the marine environment. A contract with OSRL is in place, allowing the rapid deployment of oil spill response equipment and personnel in the event of a large oil spill incident. Specific response equipment would be available including booms to contain surface spills at sea or protect sensitive shorelines. Ultimately, the type and size of spill, along with the metocean conditions at the time of the spill, will dictate which of these resources is most suitable for the spill event. Additional shore clean-up equipment is also available.

With the measures in place to prevent an oil spill incident from happening and the oil spill contingency planning and response resources available to the Well Operator/Installation Operator in the event of a large oil spill event, the residual environmental risk posed by the proposed Cambo Field Development is judged to be reduced to an acceptable level.

13.8 Catastrophic Loss of the FPSO, MODU, a Vessel or the Helicopter

Under extreme circumstances, the FPSO, MODU, a support vessel or a helicopter may sink. This could be caused by a variety of reasons, such as a serious blow-out situation, shallow gas release, a collision with another vessel, a freak weather event or other natural disaster, a catastrophic error during ballasting or offloading of the FPSO or ballasting of the MODU. These events are extremely rare and happen so infrequently that no reliable statistics could be obtained to quantify them.

A raft of mitigation measures are in place for preventing such an event from happening. These include all mitigation measures mentioned in Section 13.6 above, as well as the following:

- The FPSO and the MODU will be inspected for sea worthiness and the Well Operator/Installation Operator audited prior to operations commencing;
- The MODU will have disconnect procedures in place, to be able to quickly move off the wells, if required;
- A blow-out preventer will be installed after the 17½" section is drilled and the 20" × 13⅜" casing cemented in place;
- Well control procedures will be in place and an appropriate mud programme will be designed in order to maintain well control at all times;
- Personnel will be appropriately trained, experienced and certified;
- The competence and experience of all contractors will be assessed before they are contracted;
- All supply vessels will operate via DP, to reduce the likelihood of a collision;
- A digital site survey for drilling hazards has been carried out to confirm that there is no shallow gas in the area;
- A 500 m exclusion zone will be enforced around the FPSO and the MODU for general shipping in the area;
- A standby vessel will be on site throughout the life of field to enforce the 500 m exclusion zone;
- The FPSO and the MODU and associated vessels will use appropriate lighting;
- The suitability of supply, other support vessels and the helicopter will be assessed before they are contracted;
- The standby vessel will be equipped with radar and communication equipment so that any vessel in the area can be detected and contacted, if required;
- The United Kingdom Hydrographic Office (UKHO) and Ministry of Defence (MoD) will be kept informed of drilling activities.

In the event of the loss of the FPSO, the MODU, a support vessel or a helicopter, it would be unlikely that the vessel or aircraft would be salvageable in this deepwater environment and, therefore, would most probably remain on the seabed as a wreck. Attempts would be made to salvage any remaining hydrocarbons and other potentially harmful products onboard the FPSO/MODU/vessel, although it should be noted that, in practice, these types of operations are prone to causing pollution incidents. The potential impact of the release of oil to the marine environment is described above in Section 13.5.

The wreck of the FPSO, MODU, vessel or helicopter would be marked on navigational charts to prevent the snagging of fishing nets and other towed equipment. Shipwrecks UK (2019) has identified more than 46,000 wrecks in the waters around the UK and Ireland. In general, the presence of wrecks on the seabed is not considered to have any long lasting negative environmental effects. Therefore, given the remote chance of such an event happening due to appropriate mitigation measures in place, and minimal negative long-term environmental impacts, the residual impact of a loss of rig is considered to be insignificant.