Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production

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Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production

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Wood Environment & Infrastructure Solutions UK Limited – February 2019

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Contents

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Part One: Introduction and Scope

1. Introduction

1.1 Overview of this Document

In 2015-2018, the European Commission initiated an exchange of information with a view to developing a Guidance Document on best available techniques (BAT) in upstream hydrocarbon exploration and production, specifically with regard to environmental protection. The aim of this exercise was to identify best available techniques and best risk management approaches for selected key environmental issues during onshore and offshore hydrocarbons exploration and production activities.

The Guidance Document has been developed based on information provided by a Technical Working Group (TWG) in response to data collection questionnaires; extensive comments on drafts of the Guidance Document; as well as additional data provided by TWG members and collected by the project team. A description of the process involved in developing the Guidance Document is included in Appendix A.

The document distinguishes onshore and offshore activities for the exploration and production of hydrocarbons. It is organised as follows:

- Part One provides an introduction (Section 1) and the scope of the document (Section 2);
- Part Two (Section 3) presents risk management approaches in hydrocarbons activities;
- Part Three (Sections 4 to 16) presents guidance for onshore activities;
- Part Four (Sections 17 to 26) presents guidance for offshore activities;
- Appendix A presents an overview of the information exchange process;
- Appendix B presents a glossary of terminology and abbreviations used; and
- Appendix C presents an overview of the steps involved in performing a BAT Assessment

The techniques listed and described in the Guidance Document represent the best and most current techniques adopted in upstream oil and gas operations at the time of writing, and their inclusion is neither intended to be prescriptive nor exhaustive. Other techniques may be used. Where environmental performance levels are included in the Guidance Document this is to allow a comparison of the performance of techniques such that a desired environmental outcome commensurate with BAT can be achieved.

1.2 Purpose of the Guidance Document

The main driver behind the Guidance Document is to improve protection of the environment. Although the hydrocarbons industry has operated for many years with a range of far reaching regulations, standards and guidance in this regard, this Guidance Document attempts to unify these for the European context in terms of practices and intent.

The identification of best practice in the document is intended to serve as guidance for organisations engaged in hydrocarbons activities and for the regulatory/permitting authorities[1] to draw upon when

[1] Note that this Guidance Document uses the term "Regulatory Authority" to cover regulatory/permitting authorities for hydrocarbons activities, including for jurisdictions where either a single or multiple such authorities exist.

planning new facilities or carrying out modifications to existing facilities[2], planning changes and investments, as well as in permitting activities across the European Union (EU). The Guidance Document is a non-binding tool designed to support organisations and the Regulatory Authorities with this objective in mind.

The Guidance Document is not prescriptive in defining BAT or best risk management approaches and does not attempt to list all techniques presently available (i.e. it is not intended to be exhaustive). Organisations are still able to apply or propose to use other techniques than those listed in the Guidance Document. The Guidance Document is intended to provide information against which hydrocarbons organisations and the Regulatory Authority can compare the performance of their preferred BAT, to ensure a high level of environmental protection in the sector is maintained and continuously improved upon. The Guidance Document should not be seen as a barrier to the industry to continue its development of new and novel approaches to address environmental issues.

The Guidance Document attempts to consider the extent to which geographic, environmental and technical characteristics (e.g. age, design, accessibility) may impact on the application of the techniques identified as BAT. Such characteristics may prevent the application of a technique or techniques that constitute BAT for certain individual facilities.

1.3 Context and Organisation of the Guidance Document

1.3.1 Identification of Activities, BAT and Best Risk Management Approaches

The Guidance Document sets out guidance relevant to a number of onshore and offshore hydrocarbons 'activities'. These activities were identified through extensive exchange amongst the TWG, at and between three meetings of the TWG. They have been identified as activities recognised by the hydrocarbons industry, policymakers, academia and civil society more broadly, as having potential environmental impacts and for which approaches and techniques to manage those impacts may be readily specified. For each activity, a summary including potential for environmental impacts is provided. Each Section then includes details of the identified "best risk management approaches" and "best available techniques" (BAT) to address potential environmental impacts[3]. These two concepts are described in the following Sections.

Best risk management approaches and BAT were identified and developed through a literature search and gap analysis of existing guidance, as well as the information exchange with the TWG (Appendix A). Existing guidance and inputs were subject to a review for relevance and sufficiency in terms of: coverage of EU areas; ability to address environmental issues in full; accessibility to hydrocarbons organisations and Regulatory Authorities (publicly available or otherwise); and recency of publication. This information was supplemented extensively with the first-hand technical knowledge and experience of hydrocarbons industry organisations and Regulatory Authorities. The outcome was a collation of best and current practices applied by industry.

1.3.2 Best Risk Management Approaches

Best risk management approaches are those approaches that are currently considered to be the most effective approaches to managing risk at corporate and operational levels. Rather than an objective measure,

[2] The terms 'new' and 'existing' are deliberately not defined within the Guidance Document, nor is what constitutes a 'modification' that would warrant implementation of new techniques. This is a matter to be determined between the Regulatory Authority and the hydrocarbons organisation.

[3] Note that for some activities the TWG did not agree to covering BAT, but only best risk management approaches (Offshore Activities 2, 3 and 9).

"best" in terms of risk management approaches is defined in terms of how widespread the approaches are throughout the hydrocarbons industry and how effective they are in managing environmental risks and impacts.

Despite the fact that many risk management approaches are not specifically addressed in regulations, a level of commonality exists across the industry in their application. As described in Section 3, risk management approaches are aligned with, and many contain, steps within the Risk Management process set out in ISO31000. Since they are not prescriptive, best risk management approaches are seen as continually evolving and adaptable to the environments in which they are applied. Hence, existing approaches may also be superseded by more effective approaches in the future or enhanced based on lessons learned through their application.

It is only in the context of applying best risk management approaches and in conjunction with their implementation at corporate and operational levels that the identification and selection of BAT should proceed. In other words, the selection of BAT for a specific facility or operation should be preceded by giving due consideration to best risk management approaches embedded within a robust overarching management system framework. The Guidance Document recognises that best risk management approaches may equally apply to routine (foreseen) and unintended (accidental) events, as has been the industry norm for decades.

The Guidance Document also acknowledges that risk management approaches are often put in place to comply with legislation. However, legislation is typically not specific on the way in which an organisation should attempt to meet requirements. In many instances, different approaches may be applied to do so.

1.3.3 Best Available Techniques

Best available techniques (BAT) are defined as the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques for providing the basis for emission limit values and other permit conditions designed to prevent and, where that is not practicable, to reduce, emissions and the impact on the environment as a whole:

a) 'techniques' includes both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned;

b) 'available techniques' means those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator;

c) 'best' means most effective in achieving a high general level of protection of the environment.

For clarity, this encompasses techniques that can be used to address both routine (foreseen) and unintended (accidental) emissions and other impacts on the environment.

The BAT concept has been embedded in European environmental policy since the 1970s, and has evolved from various similar definitions, such as 'best practicable means', 'best available technology' and 'best available techniques not entailing excessive costs' (BATNEEC). It is a concept now widely applied across many industrial activities and encompasses the best of those practices already being applied to protect the environment as a whole (i.e. covering all environmental media, such as air, water, soil and groundwater).

Both BAT and best risk management approaches are determined at the level of individual facilities, taking into account their specific characteristics such as age, location and design of the facility. Cross-media effects should be considered when assessing BAT options that are intended to address different environmental aspects or those associated with different hydrocarbon activities. BAT assessment should account for the ways in which options may be selected such that the least overall environmental impact occurs.

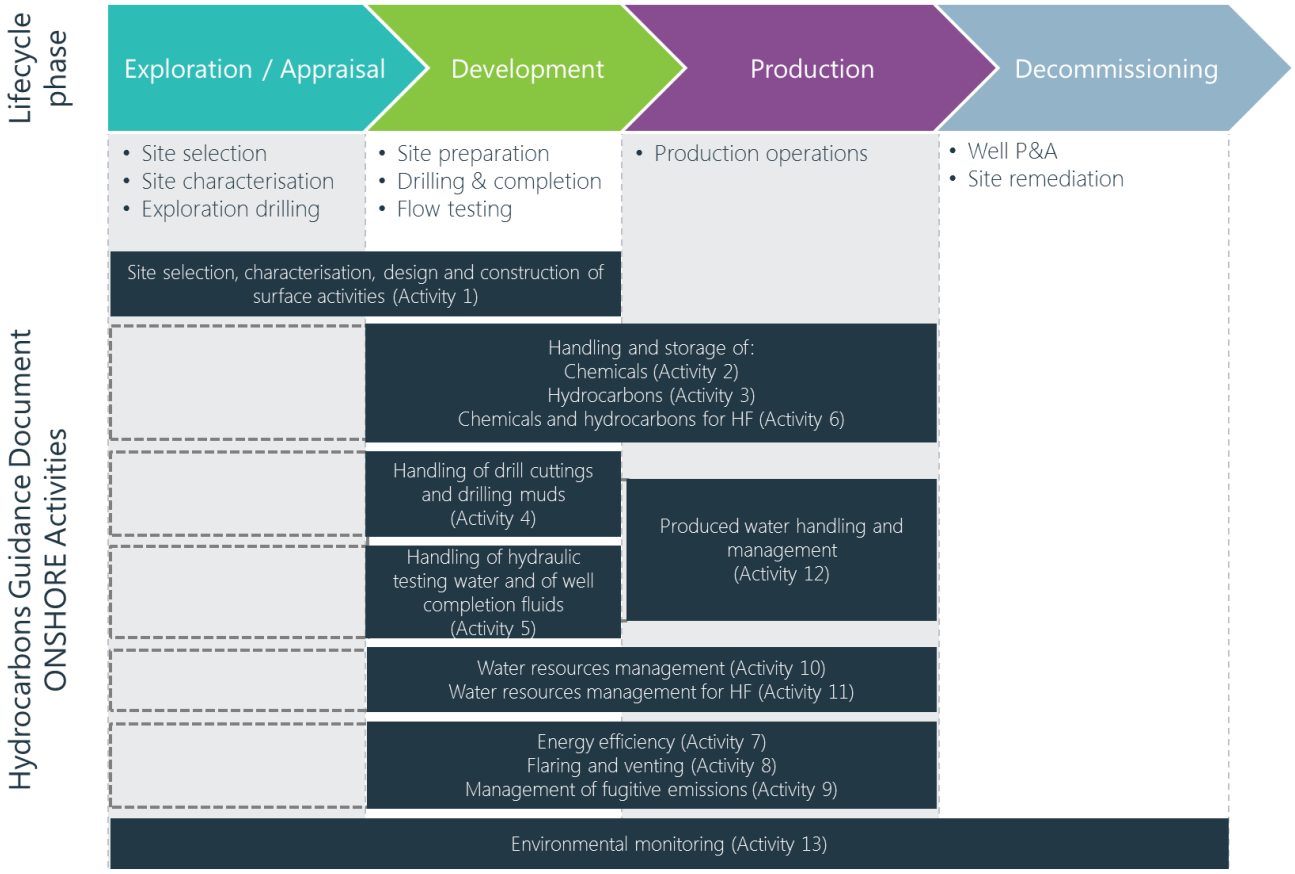
BAT and risk management approaches must not compromise safety and should be consistent with related activities to ensure safety. Details on the definition and scope of best risk management approaches are provided in Section 3. Further information on performing a BAT assessment is provided in Appendix C.

1.3.4 Lifecycle Context

The Guidance Document provides information on BAT and risk management approaches that are applicable throughout the hydrocarbon operations lifecycle. Figure 1.1 and Figure 1.2 provide an overview of hydrocarbon lifecycle phases and the applicability of the activities described within the Guidance Document to each of these. The lifecycle consists of four distinct phases, typically considered under the following headings:

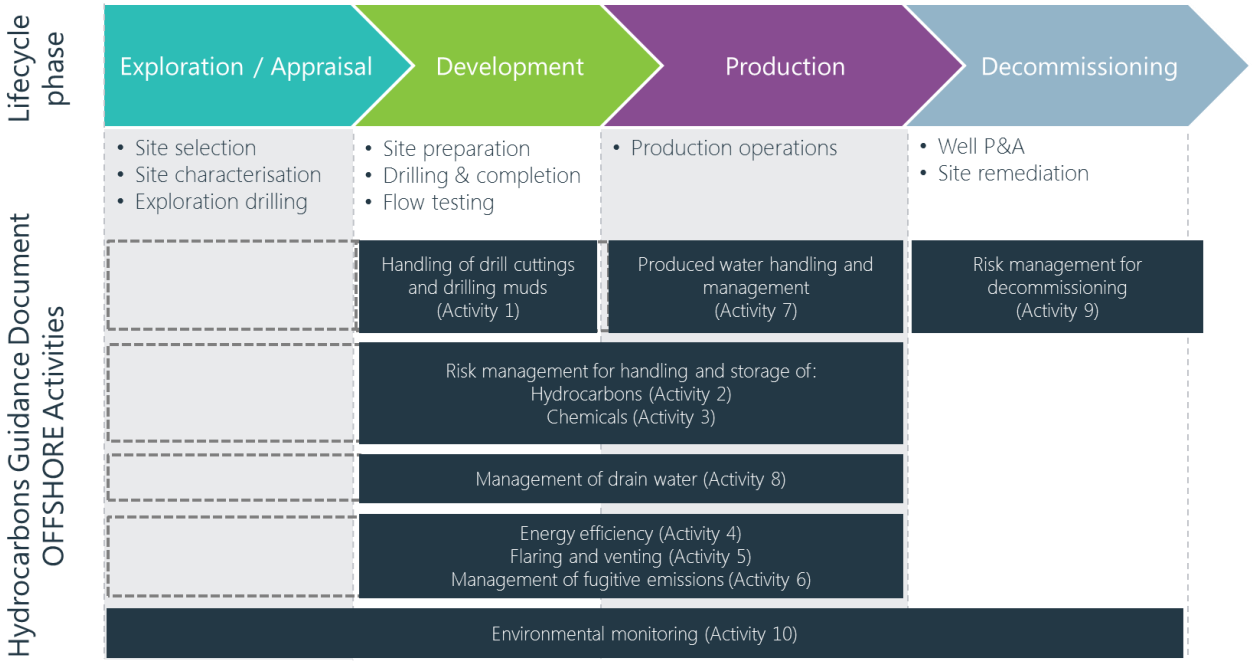
- Exploration / Appraisal – Exploration involves prospecting for hydrocarbon reserves, primarily using seismic surveys and well drilling. Determining the most promising location(s) in which to drill requires in-depth analysis of geological and geophysical information obtained through survey, and carries an inherently high risk of failure to find hydrocarbons. Exploration drilling offers valuable data on subsurface properties, leading to conclusions regarding size, depth, and reservoir characteristics. If potentially viable reserves are discovered, appraisal activities (i.e. drilling, surveying and sampling) follow to better understand the discovery and reduce uncertainty.
- Development – Development involves preparing a plan to exploit the discovery, including proposed number and type of wells, required facilities and their design, and means of hydrocarbons export. It also involves the implementation of this plan in terms of the construction and commissioning of facilities on site, once designed. Depending on location, size and complexity of the development, this phase can continue for an extended period before production is able to commence.
- Production – Production is the phase during which hydrocarbons are extracted from an oil or gas field. Depending on the size of the reserves concerned, this phase can last from several years up to several decades, and may occur in conjunction with further development if new areas of interest are discovered. Production is typically a continuous operation involving human operators or automation (or both) depending on the size, scale and type of operation.
- Decommissioning – Decommissioning describes the removal of facilities and remediation of a site used for the production of hydrocarbons. It usually refers to offshore facilities, and indeed the Guidance Document only considers decommissioning for offshore facilities. Offshore oil and gas facilities are often complex structures, requiring considerable planning and execution time to dismantle. Decommissioning broadly covers end of life management of facility infrastructure, wells and pipelines - in terms of reuse, removal or leaving-in-place.

Figure 1.1 Onshore lifecycle and activities addressed in the Guidance Document



Note: dotted lines represent onshore activities that take place but which are not addressed in the Guidance Document

Figure 1.2 Offshore lifecycle and activities addressed in the Guidance Document



Note: dotted lines represent offshore activities that take place but which are not addressed in the Guidance Document

2. Scope

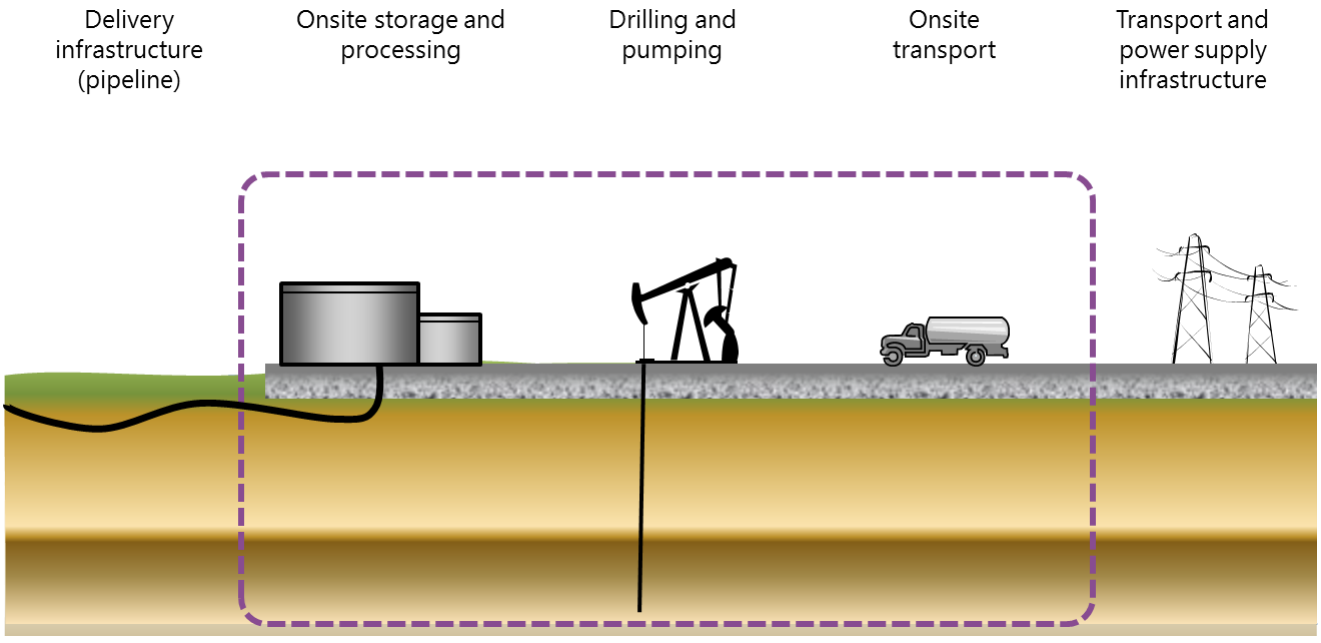
2.1 Activities Covered

The scope of the Guidance Document was agreed in cooperation with the Technical Working Group (TWG). For more information about the TWG, please refer to the EU Transparency Register[4].

The scope of the Guidance Document is illustrated at a high level in Figure 2.1 and Figure 2.2 in terms of activities, processes and technologies. All activities that occur outside of the red dotted lines are excluded from the scope of the Guidance Document. The tables in this Section set out in further detail the facilities and activities covered by the Guidance Document, as agreed at the TWG meeting in October 2016.

The Guidance Document addresses the environmental risks and impacts associated with the upstream exploration and production of onshore and offshore conventional and unconventional hydrocarbons. It does not cover any 'downstream' activities such as processing of crude oil and gas, and does not cover the transport of oil, gas or other resources to, from or between oil and gas facilities.

Figure 2.1 Scope of Guidance Document for Onshore



For onshore, the activities covered by the Guidance Document are presented in Table 2.1.

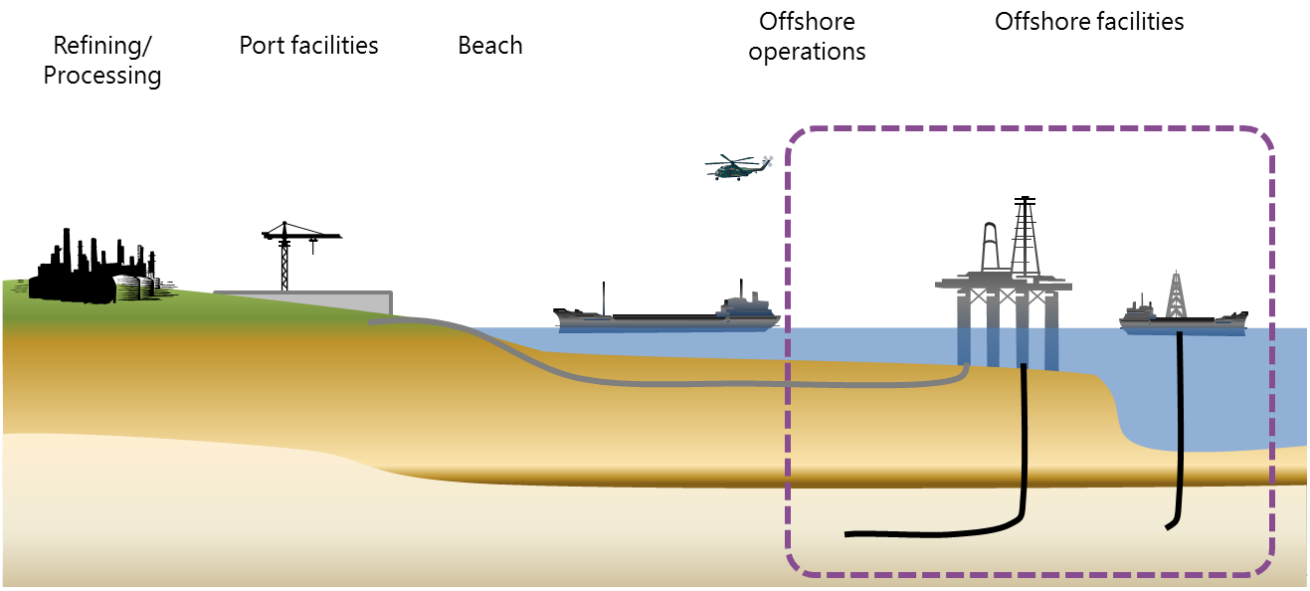
Table 2.1 Activities Covered by the Guidance Document for Onshore

Activity number	Activity name

[4] http://ec.europa.eu/transparency/regexpert/index.cfm?do=groupDetail.groupDetail&groupID=3348

Activity number	Activity name
1	Site selection, characterisation, design and construction of surface activities
2	Handling and storage of chemicals
3	Handling and storage of hydrocarbons
4	Handling of drill cuttings and drilling muds
5	Handling of hydraulic testing water and of well completion fluids
6	Management of hydrocarbons and chemicals – Well stimulation using hydraulic fracturing
7	Energy efficiency
8	Flaring and venting
9	Management of fugitive emissions
10	Water resources management
11	Water resources management for hydraulic fracturing
12	Produced water handling and management
13	Environmental monitoring

Figure 2.2 Scope of Guidance Document for Offshore



For offshore, the activities included in the Guidance Document are presented in Table 2.2.

Table 2.2 Activities Covered by the Guidance Document for Offshore

Activity number	Activity name
1	Handling of drill cuttings and drilling muds
2	Risk management for handling and storage of hydrocarbons
3	Risk management for handling and storage of chemicals
4	Energy efficiency
5	Flaring and venting
6	Management of fugitive emissions
7	Produced water handling and management
8	Management of drain water
9	Risk management for facility decommissioning
10	Environmental monitoring

2.2 General Clarifications on Scope

2.2.1 Prioritisation of the TWG's Work

The Guidance Document has been developed based on inputs from the TWG. Given that the time and resources of the TWG were limited and that existing guidance and standards can be found in relation to a number of environmental issues, the TWG did not seek to identify BAT for all environmental issues. Instead, its work was prioritised based on the areas where there is added value (e.g. in providing information on the best-performing facilities) with the possibility to provide cross-references from the Guidance Document to external sources of existing information and guidance.

2.2.2 Overlaps with Other Multinational Fora, Guidance and Legislation

The Guidance Document has been developed to avoid duplication of effort within other EU guidance or legislative documents, in particular the best available techniques reference document (BREF) on management of waste from the extractive industries (MWEI) and the Industrial Emissions Directive (IED) BREFs, such as on Large Combustion Plants (LCP), Waste Treatment (WT), Energy Efficiency (ENE), Refining of Mineral Oil and Gas (REF), Emissions from Storage (EFS) and Common Waste Water Treatment (CWW) techniques.

There are also various potential overlaps with other legislation. In particular this includes the: Offshore Safety Directive and work of the EU Offshore Authorities Group (OAG) and the Seveso III Directive. Furthermore, there are clearly links with work under groups such as those under the Oslo and Paris (OSPAR) and Barcelona Conventions. These groups operate independently from the EU albeit that the EU and its Member States are generally members of such groups. It was recognised, however, that information developed under such Conventions is a source of valuable information for the Guidance Document.

The Guidance Document does not attempt to reference all individual guidance but is rather a standalone document that should be aligned with any existing guidance that has been identified by the TWG.

2.2.3 Potential Conflict Where Existing 'Goal-setting' Approaches Exist

Goal setting approaches are used, for example, in certain member states and under certain multilateral environmental agreements (e.g. OSPAR) and are a core component of the Offshore Safety Directive. These allow a flexible approach in the choice of technology and systems to meet safety and environmental standards.

In some cases, the Guidance Document simply makes direct reference to BAT developed under such multilateral environmental agreements (e.g. the OSPAR Convention), rather than seeking to identify BAT separately.

2.2.4 Applicability of Techniques Identified in the Guidance Document

The nature of hydrocarbons activities and the characteristics of hydrocarbon facilities onshore and offshore may exhibit both variation and similarity across the hydrocarbons industry. Hence while best risk management approaches and BAT at one facility may be similar to those at others, this may not always be the case due to differences in the local environment, geography, nature of the hydrocarbons, age of facility, etc.

The techniques identified in the Guidance Document are generally widely applicable, as confirmed through reference sources within which their applicability is described, and as substantiated by inputs from the TWG. Where techniques are highly case specific, their limitations and constraints are set out in overview within the individual activity Sections. This may include, for example whether techniques apply to new, substantially modified and existing facilities. Ultimately it is at the discretion of oil and gas organisations undertaking an activity, in conjunction with the Regulatory Authority, to make this determination. For existing assets and projects, opportunities to apply techniques will depend on a range of site-specific constraints and value drivers including geographical location, climatic conditions, hydrocarbons/ reservoir type, and scale of activity. The phase of operation, described in Section 1.3.4, is also important – the longer duration of the production compared to the exploration phase, for example, may have an influence on the measures and techniques selected to manage risks.

2.2.5 Potential for Contradiction Where Member States Prohibit Certain Activities

Some Member States have a prohibition or moratorium on certain activities, particularly hydraulic fracturing (HF), including high-volume hydraulic fracturing (HVHF) onshore (e.g. in shale). The Guidance Document includes separate consideration of techniques applicable where HF takes place, and explicitly recognises that these parts of the Guidance Document are not relevant in Member States where such prohibitions exist.

2.2.6 Potential Adverse Effect on Safety

It is expected that the techniques and approaches identified in the Guidance Document should be applied in such a way as to not compromise safety and should be consistent with related activities to ensure safety. The Guidance Document acknowledges that many best risk management approaches and BAT have both safety and environmental relevance and are often applied to satisfy requirements for both.

2.2.7 Improvement of the Protection of the Environment

The main environmental benefit of the Guidance Document is the identification and overview of best management approaches and BAT for onshore and offshore contexts which may serve to guide hydrocarbons industry organisations and the Regulatory Authority in their work.

The Guidance Document is intended to reflect the best of existing performance and practice in the real world. It builds on current practice identified for activities, and in geographies, in which the upstream hydrocarbons industry is already well established. In areas where the EU hydrocarbon sector is in the

relatively early stages of development, e.g. shale gas, information from countries with more widespread application of exploration and production techniques form valuable sources of information, albeit the suitability of techniques currently applied outside of the EU has been considered in terms of their suitability for EU circumstances. Best risk management approaches and BAT in areas where hydrocarbons exploration and production has been going on for a number of decades are likely to be of particular relevance to areas where hydrocarbons exploration and production has only recently commenced.

2.2.8 Tolerability of Environmental Risk

The upstream hydrocarbons industry currently has no EU-wide guidance on "risk tolerability" specific to environmental risk. For major accidents leading to unintended releases of hydrocarbons to the environment, the default tolerability criteria typically follow those for safety risk, and the principle of reducing risk to As Low as Reasonably Practicable (ALARP).

ALARP demonstration may include both qualitative and quantitative approaches, with decision context and assessment techniques chosen dependent on type of activity, levels of uncertainty, and stakeholder influence [1]. More complex situations may be supported by both engineering analysis and cost-benefit analysis (CBA), which may draw on metrics to arrive at tolerability limits for risks entailing fatalities in the workplace, e.g. Individual Risk per Annum (IRPA) and Potential Loss of Life (PLL) [2,3]. These are then compared with the implementation cost (in terms of human, physical and financial resources) of intervention(s) to reduce risk, to demonstrate ALARP. Guidance on performing environmental ALARP demonstration is emerging, including for onshore operations in the UK with the *Guideline: Environmental Risk Tolerability for COMAH Establishments* (CDOIF, 2014) [4]. This guidance leverages criteria from safety risk, in addition to environmental specific criteria such as consequence assessment (e.g. use of predicted no effect concentration, PNECs or LC50/3[5]) where appropriate. In addition, the Environmental Liability Directive [5] which emphasises the 'polluter pays' principle, holds organisations responsible for environmental damage and implicated in any remediation costs. Incentive hence exists for organisations to proactively assess and manage their environmental risks considering the magnitude of these potential expenses.

The Guidance Document does not offer specific steer on tolerability of environmental risk, and it is expected that this is an area that will continue to be managed at the discretion of the Regulatory Authority.

2.2.9 Recognition of Existing Engineering Standards and Requirements for Asset Integrity

Ensuring asset integrity e.g. through application of appropriate engineering standards, is a key element of environmental protection. The Guidance Document outlines elements of engineering design to be applied rather than providing details, and where appropriate identifies environmental performance levels or indicators (e.g. for emissions of defined pollutants) that should be achieved as well as examples of (some of the) techniques that may be used to achieve those performance levels, while recognising that achievable environmental performance is affected by facility-specific factors.

2.3 References for Section 2

[1] OGUK, 2014. Guidance on Risk Related Decision Making, Issue 2.

[2] UK Health & Safety Executive, 2001. Reducing risks, protecting people: HSE's decision-making process. Retrieved from http://www.hse.gov.uk/risk/theory/r2p2.pdf.

[5] LC stands for "Lethal Concentration".

[3] UK Health & Safety Executive (n.d.) HSE principles for Cost Benefit Analysis (CBA) in support of ALARP decisions. Retrieved from http://www.hse.gov.uk/Risk/theory/alarpcba.htm.

[4] Chemical and Downstream Oil Industries Forum (CDOIF), 2014. Guideline: Environmental Risk Tolerability for COMAH Establishments (UK), v2.

[5] Directive 2004/35/EC of the European Parliament and of the Council of 21 April 2004 on environmental liability with regard to the prevention and remedying of environmental damage (Environmental Liability Directive).

Part Two: Risk Management Approaches

3. Risk Management Approaches in Hydrocarbons Exploration and Production

3.1 Introduction

This Section provides an overview of the approaches to risk management applied by the upstream hydrocarbons industry, including the strategies and processes for managing risks and potential impacts on the natural environment. It draws significantly on experience from the offshore hydrocarbons industry, but similar principles also apply to onshore oil and gas. This overview offers insight into the regulatory context, a review of approaches taken by organisations at corporate and operational levels, and examples of approaches considered as good practice by the industry. The overview is intended to complement other Sections in the Guidance Document and demonstrate the way in which risk management approaches are connected to selecting BAT in design and operations at a facility level.

In the upstream hydrocarbons industry, "risk management approaches" are those approaches taken by organisations involved in hydrocarbon exploration and production activities, to minimise the likelihood and severity of impacts from accidents and environmental incidents, as well as from routine operations. Such approaches represent strategies that aim to prevent, detect, control and mitigate impacts, by reducing their frequency of occurrence and/or their magnitude. Risk management approaches precede consideration of BAT since it is in the context of a comprehensive risk management process that technical evaluations necessary to arrive at BAT are supported.

3.2 Regulatory Context

Risk-management approaches for safety and environmental hazards have been applied within the upstream hydrocarbons industry for several decades and are considered as good practice by authorities that operate "goal-setting" regulatory regimes. Such regimes place the onus on hydrocarbons organisations to meet goals for continual performance improvement by implementing measures adapted to their specific organisational and operational contexts. This differs from so-called "prescriptive" regulation, whereby authorities determine specific measures to be followed – a stance sometimes viewed as offering less scope and encouragement for innovation and the proactive management of risks. Nevertheless, prescriptive regulation is practiced in several EU Member States, often in combination with goal-setting elements. Here, innovation may also occur providing there is scope for the transfer of expert knowledge between hydrocarbons organisations and the Regulatory Authority. Either prescriptive, goal-setting, or a combination of the two approaches is considered to be equally valid in terms of managing risks.

"Best risk management" involves the application of structured and coherent approaches to identifying, assessing and managing risk in line with organisational objectives as well as broader regulatory and ultimately societal goals. In principle, its aims are to: identify all possible hazards; precisely characterise hazards in terms of root causes; make conservative and informed estimates of risk; arrive at an evaluation of risk tolerability consistent with organisational and regulatory goals; and put in place barriers to ensure that risk can be considered tolerable by an organisation.

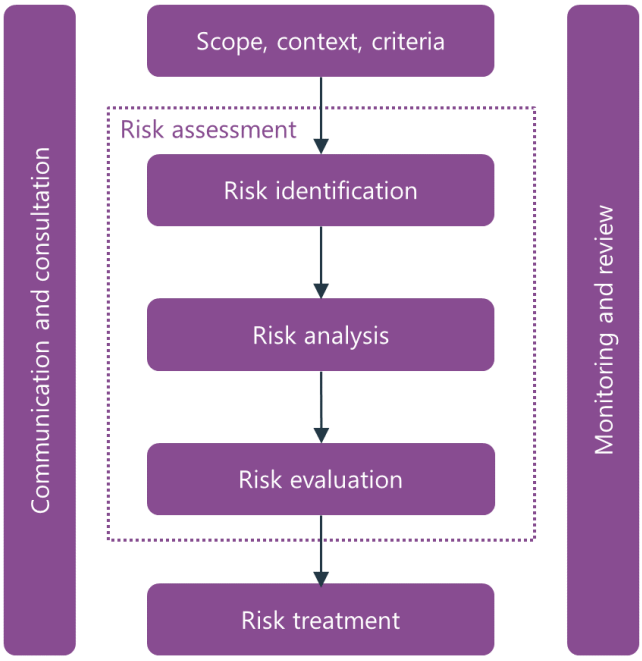
For activities carried out by the hydrocarbons industry, the Offshore Safety Directive [1] (for offshore) and Seveso III Directive [2] (for onshore) place significant emphasis on risk management, with the objective to reduce the risk of major accidents (e.g. to ALARP, where the costs of further risk reduction grossly outweigh the benefits). A similar principle and intent are applied by the industry to safety and environmental hazards which do not meet criteria for being a major accident or incident, but that nevertheless have the potential to cause harm to human life and the environment. This Guidance Document covers risk management

approaches for organisations operating both onshore and offshore, not only for environmental risks associated with major accidents but also for those accidents which do not meet the criteria to be considered 'major' and for those risks that arise during routine operations.

3.3 Risk Management Framework

Risk management as a discipline is guided by international standards and frameworks, including *ISO31000: 2018 Risk Management* [3] (Figure 3.1). This makes it a useful standard for describing what are universally applicable risk management principles and processes. Other standards, such as ISO17776: 2016 [4] for the offshore industry, also complement ISO31000:2018 by providing specific industry guidance on risk management.

Figure 3.1 Risk Management Process (ISO 31000:2018)



Although the risk management process as described in ISO 31000 has a corporate (i.e. "organisation-wide") focus, it may be applied equally to situation-specific risk decision making, as is the case in the upstream hydrocarbons industry. The generic steps and objectives within the process are:

- Scope, Context and Criteria – This first important step involves producing an accurate picture of the circumstances under review and defining as many external and internal parameters as necessary to support decision making. It involves definition of the scope of an organisation's risk management activities; its external and internal context; and definition of risk criteria against which the significance of risks and their tolerability can be evaluated. In the upstream hydrocarbons industry these include, for example:
  - Corporate context – Organisation objectives, roles and responsibilities, required resources and methods, industry and regulatory context, interests of key stakeholders;
  - Environmental scope – Site-specific factors such as geography, terrestrial and/or marine characteristics, external factors such as natural and human-induced environmental change, e.g. climate change, proximity of population, etc.;

- Infrastructure scope – Facility design parameters, construction requirements, operating limits, hazardous materials and processes, interaction with existing facilities; and
- Risk context – Risk management goals and criteria consistent with industry practice and societal expectations, to establish risk tolerability against which analysed risk can subsequently be evaluated, and setting criteria for defining events, e.g. major accidents and environmental incidents.

- Risk Assessment: The Risk Assessment component of risk management is concerned with identifying, analysing and evaluating risk within a specific organisational and operational context. Risk assessment is expected to cover all types of risks in a systematic and holistic way which may for example include, but not be limited to, technical failures, human error, software bugs and security threats. Risk Assessment consists of the following steps:
  - Risk Identification – Risk Identification represents the first stage of Risk Assessment and uses a structured approach to account for and describe all potential hazards, regardless of magnitude or likelihood of occurrence. The result should be a comprehensive list of potential hazards. Note that the terms 'hazard' and 'risk' are often (incorrectly) used interchangeably in everyday parlance, whereas the upstream hydrocarbons industry colloquially understands risk as the measure of significance of a hazard. ISO31000:2018 formally defines risk as the effect of uncertainty on objectives [3]. This step is often hence referred to by the industry as "Hazard Identification";
  - Risk Analysis – Risk Analysis involves a qualitative and/or quantitative review of hazards to clarify their root causes, likelihood, consequences, and existing barriers in place to avoid them entirely or to minimise potential impacts. Risk arising from a hazard is calculated using the simple relation:

$$Risk = Likelihood\ of\ occurrence \times Consequence(s)\ of\ occurrence$$

  - The analysis should accurately account for any assumptions, limitations and sensitivities, which should be carefully considered and clearly communicated along with its overall findings. Ranking of risks may also be performed to identify those of highest priority;
  - Risk Evaluation – Risk Evaluation is used to compare the level of risk found by Risk Analysis with criteria that were set at the start of the process. The outcome of this evaluation may be to consider additional measures or barriers to further reduce risk. Evaluation decisions are generally taken in accordance with organisational, industry and regulatory goals and draw on externally accepted societal norms.
- Risk Treatment – Although not standard terminology within the upstream hydrocarbons industry, Risk Treatment is applied in practice, and involves taking additional steps to manage risk. Risk treatment may include a cost-benefit analysis to determine whether further risk reduction measures should be implemented. It is also at this stage that, for operational risk management, Safety and Environmentally Critical Elements (SECEs) are identified and Performance Standards produced to ensure the continuing integrity of hazard barriers. Risk Treatment options also include techniques considered as BAT, and these are described in Section 3.5. In addition, the "Mitigation Hierarchy" should be considered (refer also to Section 3.5).

The ISO 31000 risk management process also relies on interaction between each of its steps and the following process components:

- Communication and consultation – Best risk management approaches include provision for communication and consultation with internal and external stakeholders, including reporting of performance. Internal stakeholders may be decision makers with broad corporate perspective,

technical authorities, and change management functions. External stakeholders may include industry experts, policy makers, and civil society organisations, the input from whom may help to develop industry and societal perspectives within organisations;

- Monitoring and review – Best risk management approaches include periodic and ad hoc monitoring and review, with the aim of continual improvement. Monitoring may include metrics for risk management performance, and benchmarking of approaches vis-à-vis the organisation's external and internal context. Focus areas might include, for example, learning lessons from accidents incidents and near misses, or identifying emerging risks. The use of a continually updated Risk Register is one way that many organisations keep track of these continual improvement measures.

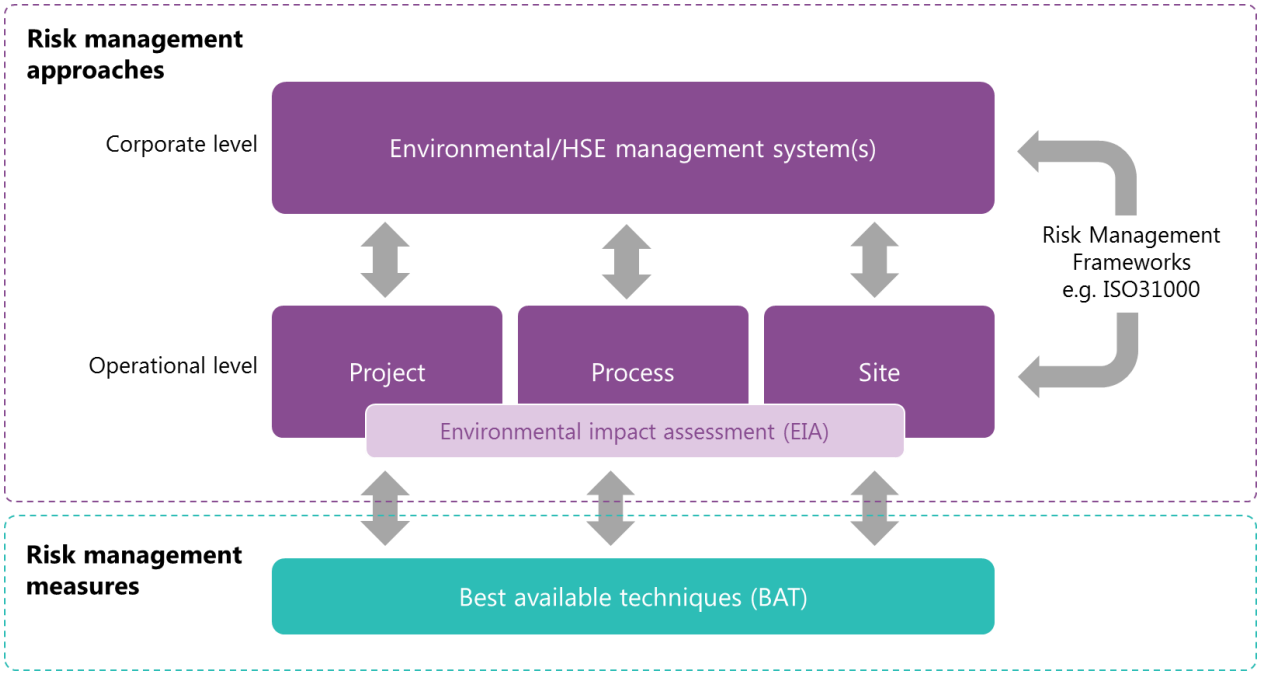
Specific examples of risk management approaches that may be applied to each of the above steps for use in environmental risk management by the upstream hydrocarbons industry are presented in Section 3.5.

3.4 Risk Management at Corporate and Operational Levels

3.4.1 Overview

Best risk management in the upstream hydrocarbons industry implies that an organisation is taking a holistic approach to ensuring that risk is accounted for at multiple organisational levels, and moreover that it is embedded within a functioning and continuously improving risk management culture. Figure 3.2 provides an overview of the interrelation between risk management at different organisational levels and BAT.

Figure 3.2 Risk Management Approaches at Corporate and Operational Levels



Risk management principles should be fully addressed within corporate management systems, including within the elements of those systems that ensure good practice is applied at operational level, i.e. on projects, sites, infrastructure, and within operational procedures. The ISO31000 Risk Management framework offers a template for risk management at different levels and may be adapted for use in full or in part depending on specific organisational requirements. Its use is complemented by numerous other standards and approaches.

In general, all hydrocarbons exploration and production activities should be subject to operational risk management approaches which take corporate level approaches as their overarching framework. At operational level it would be expected that environmental risk assessment is performed for all project, process or site activities (including their timing), to identify appropriate environmental management measures for these activities. It is only in the context of risk management approaches and following their implementation that BAT may be identified and selected.

Environmental Impact Assessment (EIA) is an overarching and systematic means of assessing of the environmental impacts arising from a proposed development (see below). EIA is included in Figure 3.2 to illustrate its connection to risk management approaches, for which it represents an operational approach, potentially applicable to any and all of project, process or site activities. Risk management measures applicable at operational level include BAT, which may also feed into the EIA.

Corporate and operational level risk management approaches are outlined further in the following Sections.

3.4.2 Corporate Level Approaches

Environmental management at corporate level is typically guided by the ISO14000 family of Standards which provide tools for organisations to manage their environmental responsibilities. ISO 14001:2015 [5], for example, maps out a framework and criteria that organisations can use to develop and implement an Environmental Management System (EMS). This Standard does not, however, state requirements for environmental performance, and its purpose is not to guide the process of risk management for specific operations or environmental aspects. Organisations must hence make use of other industry guidance to inform specific approaches for managing environmental risks (e.g. [6,7]), and must determine key external and internal issues relevant to their context, and that affect their ability to achieve the intended outcomes of an EMS.

Many industry organisations manage their environmental risks as part of an integrated corporate approach that addresses health, safety and environment (HSE). Such an approach may be implemented as an HSE Management System, consisting of high-level policies, a binding framework and a set of procedures for performing tasks, all of which are tailored to organisational needs. As well as providing a method of functioning, HSE Management Systems are a demonstration of commitment and goal-setting by organisations for the management of risks from their operations, both for their own internal benefit and from the point of view of external stakeholders.

While the content of HSE Management Systems varies, there is often similarity between systems in terms of the elements they contain. An example of elements within a typical system include:

- Commitment and Leadership – outlines the expectations of senior management and their commitment to HSE;
- Policies and Objectives – a set of overarching tenets by which the organisation intends to manage HSE;
- Organisation, Resources and Documentation – structure of the organisation as regards HSE, and the processes and procedures that apply to its functioning;
- Risk Management – ways in which the organisation manages HSE risk in specific situations (processes, sites, infrastructure, etc.);
- Planning, Implementation, Recording and Monitoring – the way in which HSE management is planned, implemented and analysed; and
- Audit and Review – the means through which HSE performance is evaluated and continuously improved, including key performance indicators (KPIs), etc.

Both the HSE Management System overall, and any information it contains relating to situation-specific risk management (e.g. processes, sites, infrastructure) may be considered as risk management approaches. While the HSE Management System should set the context for an organisation's risk management efforts, the "Risk Management" system element should reference the technical, operational and organisational processes that ensure risk management is carried out effectively. It is to here that procedures and other practical measures (including BAT) are connected.

3.4.3 Operational Level Approaches

Operational risk management describes approaches that organisations take as part of their day-to-day activities. Many hydrocarbon industry activities are well recognised as carrying inherent risk, and hence require management strategies commensurate with that risk. Operational risk management approaches may apply to projects, sites or specific processes. These are of particular importance during a project's design phase, as this is when safety and environmental hazards may still be identified early and 'engineered out' of a design, reducing the burden of risk management later. However, they should also be equally considered throughout the operational lifecycle of a project, site or specific process.

Risk management may proceed qualitatively, quantitatively or both. A qualitative approach may, for example, rely on industry experts to establish likelihood of occurrence for an accident event, while a quantitative approach might use recorded accident statistics to do this. In general, approaches must offer levels of sufficient certainty, and rigour should reflect complexity and risk magnitude. For complex systems a qualitative approach may not be sufficient to demonstrate tolerability/ acceptability of risk, and a more precise and quantitative approach may therefore be required. Criteria for selecting approaches include "type of activity" and "level of external stakeholder interest". Final decisions on measures applied may be informed by a combination of existing best practice, engineering and adherence to the "precautionary principle" [8].

Environmental risk is one component of overall risk, and is often considered not in isolation, but in conjunction with safety, health, reputation, and financial aspects, as outlined in the Sections below. The Offshore Safety Directive [1] and Seveso III Directive [2] acknowledge the significant overlap between risks with the potential to impact both people and the environment, and the industry also recognises that many of the same risk management measures apply to both. An example of where this appears in practice is (for offshore) SECEs, which are critical barriers in place to manage both major accidents and major environmental incidents [1].

Risk management approaches currently used by the industry are adaptable to a range of different facility-specific factors such as design, age, etc. and location-specific factors such as climate, geology, etc. While approaches may point to the selection of measures for one facility/location that may not necessarily be the same as those for another, they should be intended to achieve equivalent level of ambition in terms of environmental protection. Approaches are not intended to prescribe specific measures, but rather to identify the appropriate techniques (e.g. management measures for defined pollutants, monitoring requirements, etc.). Some, or all, of these techniques may be considered BAT.

Finally, environmental impacts may be considered and managed based on whether they are "planned" or "unintended". Planned impacts are those which are expected to occur and for which risk must be minimised consistent with regulations. Such impacts include routine discharges of hydrocarbons and chemicals and atmospheric emissions. Compliance requirements for such impacts are accessible in the public domain, and risk management approaches function to identify the relevant hazards and to facilitate decision-making on measures to manage them, including BAT.

Unintended environmental impacts refer to releases that are not expected to occur and result from accidents/incidents. Organisations may set their own goals for managing such potential environmental impacts, consistent with good industry practice, and to minimise the likelihood and severity of potentially negative consequences. In general, organisations are expected to identify and describe as many technical,

operational and organisational barriers as considered necessary, to demonstrate that risks have been reduced to tolerable levels.

3.5 Examples of Risk Management Approaches

3.5.1 Context

A variety of risk management approaches may be applied at operational level to address both planned and unintended environmental impacts. This Section provides an outline of some commonly implemented risk management approaches that can be considered as applicable to one or more steps within the Risk Management framework. It is worth noting that many of the approaches shown here contain similar steps, because the process used to identify, analyse, evaluate and treat risk is broadly similar.

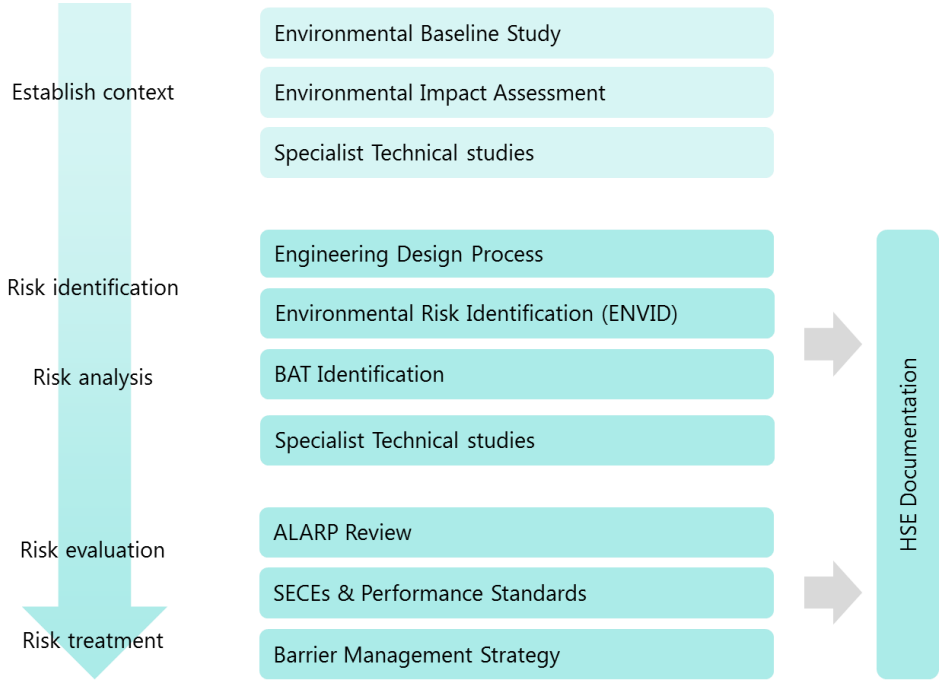
Risk management approaches as related to environmental impacts should in general adopt a hierarchical approach whereby hazards are either eliminated entirely, or measures put in place to:

- Prevent – Stop hazards from being realised in the first place;
- Detect – Be alerted at the earliest opportunity that a hazard is unfolding;
- Control – Minimise the severity of a hazard that is being realised;
- Mitigate – Reduce the impacts of a hazard and the possibility of further escalation;
- Respond – Enact emergency measures to safeguard personnel and the environment; and
- Remediate – Following an event, implement means to remediate the natural environment.

Figure 3.3 illustrates steps in the Risk Management process and examples of some of their associated risk management approaches in an upstream hydrocarbons industry context. Approaches are considered approximately aligned with the steps shown here but several approaches can also be applied at multiple steps. Many of the approaches used may also feed into an organisation's "HSE Documentation" as supporting studies (see below).

Industry guidance in this area includes [9-15].

Figure 3.3 Operational Risk Management Process and Example Risk Management Approaches



3.5.2 HSE Documentation

The management of upstream hydrocarbon operations is as much of a necessity from a safety as from an environmental perspective, and risk management for the two often overlaps. Many valuable risk management approaches for an operation are hence contained in what may be generically termed "HSE Documentation". Depending on the operation in question and the hazards involved, the scope and functionality of HSE Documentation may be intended to fulfil internal and/or external (e.g. regulatory) requirements. The role of the Regulatory Authority includes scrutinising HSE Documentation to determine whether it contains approaches that are proportionate to the risks involved, and that these reduce the risks to a tolerable level.

An example of HSE Documentation for major hazard facilities offshore is a "Major Hazards" report required by the Offshore Safety Directive [1]. For onshore facilities, the Seveso III Directive [2] requires operators of so-called "upper-tier" major hazard sites to submit a "Safety Report". Although "lower-tier" sites are not included in the above, they are expected to have in place relevant and current HSE Documentation, comprising documents that collectively demonstrate their approach to risk management.

The purpose of a Major Hazards/Safety Report is to provide an operation-specific demonstration of an organisation's HSE Management System. It identifies major accident hazards and risks for a facility, describing how these will be managed and reduced (e.g. to ALARP). It is premised on the principle that the organisation responsible for the operation holds the most in-depth knowledge and is hence best placed to self-assess its own processes, procedures and systems.

Another important aspect to Major Hazards/Safety Report development is workforce involvement, necessary to gain deeper organisational understanding and acceptance of hazards and risks. Human factors determine in large part the way in which operations are conducted offshore at an individual task level, and hence the hydrocarbons industry has gone some way towards developing guidance for improvement in this area, including training for emergency situations (e.g. [16-19]).

Offshore, the requirement for a Major Hazard Report is often covered by a "HSE Case", which has come to be accepted as international best practice for this type of demonstration. In addition to their widespread application in the hydrocarbons industry, HSE Cases and their equivalents are widely used in other industries

including defence, aerospace and nuclear. An example of the contents of an HSE Case is as follows [20], with areas of environmental focus highlighted:

- Introduction – Summary of HSE Case objectives, scope, the 'case for safety', revision and ownership of the HSE Case and an overview of the main parts;
- Facility Description – Information describing the facility to show that the design and operating philosophy is consistent with the HSE Management System, and to offer a comprehensive background for the analysis of hazards;
- HSE Management System Description – Overview of the organisation's method of managing health, safety and environment, comprising policies, objectives, organisation, responsibilities, procedures and Performance Standards;

  Within this chapter of the HSE Case should be links to specific processes to ensure, among other key factors, personnel competence and training for the operation of systems. These represent key organisational barriers for managing risk;
- Risk Management – Detailed and systematic review of all hazards and associated credible accident events and environmental incidents, and demonstration that risks of major events are reduced to ALARP. This is underpinned by a range of technical supporting studies, particularly for analysing hazard consequences and risks, e.g. Quantitative Risk Analysis (QRA).

  Within this chapter of the HSE Case should be links to specific risk assessments for environmental management including ENVID (Section 3.5.7).

  The Risk Management chapter(s) of an HSE Case typically reference a number of the risk management approaches described in this Section, as illustrated in Figure 3.3.
- Emergency Response – Processes in place for emergency response including rescue and recovery of personnel, and appropriate response measures for a major accident and/or environmental incident. This includes measures for immediate repose to a hydrocarbon spill and crisis management systems for organisational and third-party roles and responsibilities.

  Within this chapter of the HSE Case should be links to specific assessments and procedures for Spill Contingency Planning (Section 3.5.13).
- Performance Monitoring – Details on how the performance of SECEs are assured including independent verification, periodic inspection and audit.

  Within this chapter of the HSE Case should be links to Planned Maintenance System, Performance Standards and Independent Verification for SECEs (see Section 3.5.11 on Operational integrity).

For high risk activities, key industry guidance in this area includes [21-31].

3.5.3 Environmental Baseline Study

An environmental baseline is a minimum requirement for upstream hydrocarbons developments, from both a technical and regulatory standpoint. Its objective is to establish context by obtaining information and data on environmental background conditions, key features and sensitivities. The start of a project often necessitates a baseline survey, which may continue to be referred to as the project proceeds and at end-of-life, to understand how operational activities may have impacted on the baseline. The environmental baseline may be carried out as an independent study, which may then feed in to an EIA (see below). This may in turn be tied to regulatory permitting and consents processes at the approval stage of a development (e.g. as required under the IED [32]).

Environmental baselines should consider species and habitats in an area including key pathways and receptors including:

- Soil and bedrock;
- Hydrology and hydrogeology (including surface water and groundwater);
- Air and atmospheric conditions;
- Seismicity and subsidence;
- Noise;
- Ecology and biodiversity;
- Oceanography;
- Archaeological heritage;
- Social and cultural values;
- Landscape issues; and
- Other commercial values of the area.

Environmental sensitivities of an area around a facility should be assessed before, during and after operations as part of risk-based environmental monitoring programme. From a risk management perspective, an environmental baseline is used as a reference with which to objectively assess the nature and extent of any potential or realised environmental impacts. At the start of a project, this forms an input to site selection criteria and risk assessment. It may also be used to plan the most appropriate response to managing a potential environmental incident.

As an example, for onshore operations, UK Onshore Oil and Gas (UKOOG) Guidelines [33] advocate a Baseline Monitoring Programme for onshore developments and provide a risk-based framework that recommends site-specific monitoring, sampling, testing and scientific analysis, before, during and after a project. This includes beginning with a Conceptual Site Model (CSM) as a basis for identifying environmental risks and characterising them (e.g. to water, air, soil, biodiversity [34]). Environmental monitoring should continue throughout operations and provide ongoing information on changing environmental conditions.

3.5.4 Environmental Impact Assessment (EIA)

EIA is the process of assessing the environmental impacts of a proposed development and identifying management measures to avoid or minimise these. The EIA informs decision makers and provides an opportunity to identify key issues and stakeholders early in the life of a proposed development, so that potentially negative impacts can be addressed in advance of project approvals.

The application of EIA as a methodology globally has been formalised by the progressive introduction of national laws and regulations. In some cases, these are supported by policies which establish systems of institutionalised procedures to ensure that all proposed physical development, expected to be environmentally damaging, is assessed prior to authorisation and possible implementation. The EIA Directive [35] is the key driver for EIA within the EU, according to which (Article 3), the direct and indirect significant effects of a project on the following factors shall be identified, described and assessed:

(a) Population and human health;

(b) Biodiversity, with particular attention to species and habitats protected under the Habitats Directive 92/43/EEC [36] and the Birds Directive 2009/147/EC [37];

(c) Land, soil, water, air and climate;

(d) Material assets, cultural heritage and the landscape; and

(e) Interaction between the factors referred to in points (a) to (d).

EIA in the upstream hydrocarbons industry uses a structured process to obtain and evaluate environmental information which involves the following steps:

- Provide overview of pertinent legislative and regulatory considerations;
- Describe proposed development and alternatives considered, including emissions and discharges estimates;
- Describe environmental context (e.g. Environmental Baseline – see above) ;
- Compare environmental context with proposed development activities to determine potential environmental (and social) impacts, using tools (e.g. environmental modelling) as needed; and
- Produce an Environmental Management and Monitoring Plan, identifying and designing measures to manage and monitor environmental risks.

It can be seen from this list of contents that the EIA process follows similar steps as the Risk Management framework, in which a context is established, hazards are identified, risks analysed and evaluated, and treatment measures are implemented and subject to review. On the one hand EIA is a key risk management approach used for establishing the context for a proposed development, but EIA is also important in terms of the Risk Analysis that it offers and Risk Treatment management measures it specifies.

Table 3.1 presents an example of statements that may appear in a Management Plan for Waste Management as part of an EIA.

Table 3.1 Example Statements from "Engineering Philosophy" or "EIA Management Plan" for an Offshore Floating Facility

Waste Management
General
All waste management shall comply with appropriate hazardous waste legislation and regulations, and local regulatory disposal guidelines.
Putrescible Wastes
Waste discharges shall be limited to food scraps and sewage.
Sewage and food scrap disposal will conform to the requirement of MARPOL Annex IV; macerated to less than 25mm diameter prior to disposal.
No sewage or putrescible waste will be discharged within 12 nautical miles of any land.
Sewage shall be macerated to a small particle size and treated to neutralise bacteria.
Solid Wastes
All other waste shall be retained on the facility for appropriate disposal onshore (i.e. all domestic, solid, plastics and maintenance wastes).
All waste containers will be closed (i.e. with lid or netting) to prevent loss overboard.
Spent oils and lubricants shall be securely containerised and returned to shore upon campaign completion.
Hazardous Wastes
All hazardous wastes shall be documented, tracked and segregated from other streams of operational wastes.
A complete inventory will be kept of all chemicals to allow sufficient and appropriate recovery materials to be on the facility in the event of a spill (i.e. safety data sheets, labelling and handling procedures).
Other
Any drainage from decks and work areas shall be collected through a closed drain system and processed through an oil water separation system.

No sewage or putrescible waste will be discharged within 12 nautical miles of any land.
The vessel's sewage treatment system ensures that sewage is macerated to a small particle size and is treated to neutralise bacteria.
Domestic waste such as cans, glass, plastic and paper will not be discharged to sea.
The facility will be remote from any sensitive receptors such as population centres.

In order to identify measures for the potential prevention and mitigation of environmental impacts in a range of situations, the Mitigation Hierarchy may be applied. Originally developed by the Cross-Sector Biodiversity Initiative (CSBI) for managing biodiversity, the Mitigation Hierarchy is adaptable to a range of applications in which potentially negative impacts may occur. The Mitigation Hierarchy is as follows [34]:

1. Eliminate - To eliminate or modify all or part of a project to completely avoid negative environmental impacts from the project. Engineering controls to prevent unintended events;
2. Prevent - To apply measures or techniques to prevent negative environmental impacts from the project;
3. Minimise - To decrease the magnitude of those negative impacts that cannot be avoided by changing project timing, location or physical layout, engineering control to minimise emissions, modifying project infrastructure utilisation, building local infrastructure, capacity, etc. Emergency response capability for unintended events;
4. Restore - To apply rehabilitation type measures to a natural, social, cultural resource damaged by unavoidable project impacts. Recovery plans for unintended events;
5. Offset - Where none of the above approaches are practicable, to compensate for project impacts by, for example, replacement of loss/damage at another location, provision of finances, services, or other forms of compensation.

For each environmental aspect considered in the EIA process, all management options should be assessed to determine the most appropriate action. Examples of environmental aspects relevant to hydrocarbons operations include:

- Point source and fugitive emissions to air;
- Discharges to surface water and groundwater;
- Wastes produced, including waste drilling muds, drill cuttings, flowback fluid, radioactive scale and sediments and waste gas;
- Produced water;
- Noise; and
- Unintended releases of hydrocarbons or chemicals.

Finally, a key consideration when performing EIA is engagement with stakeholders at the earliest opportunity to exchange information regarding proposed activities, and to understand and include social context as part of the process. Stakeholder engagement may also continue during and after operations, depending on the nature of the activities proposed. Stakeholders may include other users of the environment, government agencies including local planning, the Regulatory Authority, special interest groups and the general public.

3.5.5 Engineering Design Process

Engineering design for hydrocarbons infrastructure forms a key part of an organisation's overall risk management approach. Best risk management from an engineering design perspective implies that an organisation is taking a proactive approach to the identification and management of safety and

environmental hazards. Engineering design should therefore also include provisions for inherent safety in design (ISD) and environmental hazard management.

For new facilities and for modifications to existing facilities, engineering design Regulations, Codes and Standards, along with engineering expertise, are used to guide the design process. A range of additional industry design guidance is also available. The engineering design process must ensure that a design meets specific best practice criteria, such that it is built to operate over the design life. Projects may therefore be engineered according to an "integrity workflow" timeline that ensures key hazards are considered at relevant design stages. For facility modifications, design should be optimised but consistent with existing infrastructure.

An engineering "Basis of Design" is a summary of functional specifications for all engineering aspects, including environmental factors. This document works in conjunction with so-called "Philosophies" for different requirements, including Operations and Maintenance, Control, Start-up and Commissioning, etc. to achieve an integrated design and risk management approach. Such Philosophies include an Environmental Philosophy, which covers key management commitments for areas such as energy, waste, emissions and discharges (refer to example in Table 3.1). Many of the design principles used to manage human safety risk are also applicable for environmental risk, since they involve ensuring the integrity of systems which if subject to failure could result in a threat to both human life and the environment. Therefore, safety management becomes entirely relevant to environmental management since the management measures for both often overlap. Such measures include those relevant to process safety, loss prevention and functional safety (i.e. as covered by IEC EN 61508 and 61511 standards [38,39]).

Engineering disciplines are responsible for environmental management within their remit as part of design, and for decisions around issues such as energy efficiency (e.g. process/mechanical disciplines), chemicals management (e.g. materials/flow assurance disciplines) and spill prevention and barriers (e.g. process/piping and layout disciplines). Environmental engineering works across the above areas, ensuring minimum standards, promoting best practice and championing risk management approaches of specific relevance to projects. Other specialists including those with knowledge in areas of relevance such as production chemistry and Health, Safety and Environment (HSE) will often also be expected to contribute.

The hydrocarbons development phase includes provision for Management of Change (MoC) for cases where new information is brought to light during engineering design and/or construction of facilities. The MoC process may indicate any conditions that are inconsistent with initial site characterisation, design or other efforts, and provide a mechanism for incorporating these findings and implementing operational improvements.

3.5.6 Specialist Technical Studies

The selection and execution of appropriate technical studies may be considered a risk management approach adopted by organisations at any of the stages of the Risk Management framework. Such studies are aimed at providing additional information necessary to characterise risk consequences and hence adequately manage risks. Steps in which technical studies often feature are establishing the scope, context and criteria, where for example environmental modelling may be used at the beginning of a project or during a facility modification, to supplement information on background conditions and the impact of potential hazard scenarios such as within an EIA or as a discrete study. They are also found within the Risk Analysis step, where quantitative studies may be performed to support Risk Analysis.

Many studies have direct relevance to environmental risk management and may be undertaken during design, as well as during operations. They may also appear as supporting studies within an organisation's HSE Documentation (see below). Studies include:

- Hazard Identification (HAZID) – High-level review of safety hazards for a facility, field development, drilling campaign, or specific operation.

- Environmental Identification (ENVID) – High-level review of environmental hazards for a facility, field development, drilling campaign, or specific operation.
- Hazard and Operability (HAZOP) – Detailed technical review of design aimed at the identification of events causing hazards or limiting the operability of facility plant and equipment.
- Bowtie Review – Review used to identify potential hazard causes and consequences together with the barriers in place to prevent their realisation and mitigate potential outcomes.
- Consequence Analyses – Studies examining the potential characteristics of unintended events such as release size, duration, potential for escalation and environmental impact. One such example is termed a Fire and Explosion Risk Analysis (FERA).
- Quantitative Risk Analysis (QRA) – An evaluation of risk associated with a hazard, involving analysis of likelihood and consequences, and expressing the results in quantitative terms.
- Best Available Techniques (BAT) Review – Review of potential environmental impacts and the best available techniques recommended to manage these.
- Spill Contingency Plan – Response arrangements in the event of a spill of hydrocarbons and/or chemicals, including credible (hydrocarbons) scenario modelling and planning (expanded further below).

3.5.7 Environmental Hazard Identification (ENVID)

ENVID is a process that may be applied during new project designs and modifications to existing facilities to identify and describe environmental hazards, their causes and consequences, and the measures in place to manage environmental impacts. ENVID may also be used as a means of arriving at an understanding of the level of risk. ENVID studies are typically performed early in a project's lifecycle, such as during Engineering Design (see below), but can equally be applied to other phases if new hazards are envisaged. ENVID follows the same method as for Hazard Identification (HAZID), which has traditionally been employed in safety management. ENVID applies to both planned events and unintentional events (accidents) [40].

ENVID typically requires a workshop team consisting of industry experts, organisation technical authorities and others with knowledge on specific engineering systems related to the infrastructure and is led by an environmental expert with knowledge of relevant environmental aspects and impacts. The team is tasked with reviewing the project following a stepwise process, which can be considered to fulfil the 'Scope, Context, Criteria', and Risk Analysis steps of the Risk Management framework. In terms of analysis, ENVID should identify environmental hazard scenarios, causes, consequences and management measures. Some, or all, of the management measures identified in the workshop may be considered as BAT (see below). ENVID may also attempt to rank risk levels (e.g. High/Medium/Low) for identified scenarios, aided by a Risk Matrix specifying criteria for hazard likelihood and severity. An example of an ENVID workshop output is presented in Table 3.2.

ENVID may be used as input to an EIA, should an EIA be required as part of carrying out a particular activity. In this case, ENVID may be used in an option review/selection capacity as part of describing the proposed development and alternatives considered (refer to EIA –Section 3.5.4). It may also be used to identify and design measures to manage and monitor environmental risks, as described in the EIA's Environmental Management and Monitoring Plan (refer to EIA - Section 3.5.4). Indeed, there are also many activities for which a full EIA may not be required, but for which an exercise able to identify potential environmental impacts and risks such as ENVID may be desirable.

Another example approach to risk assessment that operates in a similar way to ENVID is the Hazard and Effect Management Process (HEMP) [41]. HEMP is a method that reviews the identified hazards and uses a

Risk Assessment Matrix to rank the risks based on consequence and likelihood. The process is broken into structured parts that allows for a rigorous review of the potential hazards.

Regulatory Authorities within certain Member States (e.g. UK) [42] have introduced the requirement for a broad Environmental Risk Assessment (ERA) to be submitted by hydrocarbons organisations wishing to carry out onshore operations. Such an assessment is performed to support decision-making and stakeholder engagement and is intended to provide a systematic high-level review of environmental risks of proposed operations, and a demonstration of the safe and environmentally responsible management of these operations at an early stage.

Table 3.2 Hypothetical Example ENVID Worksheet for an Offshore Facility

Example Hazard	Example Description of Causes	Potential Environmental Impact	Example Management Measures already in place	Example Risk Ranking (High/Moderate/ Low)
Produced Water	Produced water is separated from the oil on board the facility and discharged to sea. It may contain heavy metals, NORMs.	Potential mortality of marine organisms, adverse effects on water quality in the immediate surrounds of the produced water outlet.	Produced Water Modelling shows high dilution rates expected for produced water discharges from the facility to open water. Monitoring of facility discharge and local water quality ensures levels of hydrocarbons, nutrients, heavy metals and water temperature are within regulatory requirements. Equipment for monitoring of oil-in-water (OIW) from the produced water stream is regularly calibrated and tested. Produced water outside set discharge criteria is diverted to the facility slop tanks for oil separation before eventual discharge to sea.	Moderate/
Cooling/ reject water	Discharge of cooling water from the facility to sea.	Disturbance to marine organisms, adverse effects on water quality.	High dilution rates mean that no changes in salinity are detectable outside a localised area. The seawater system is segregated from crude oil processing system.	Low
Solid waste	Solid waste materials including paper, cardboard, and plastic, wood, metal and machinery parts.	Adverse effects on water quality.	No solid and/or hazardous wastes are discharged to sea. Wastes are segregated, stored on board then transported to shore, where they are recycled by a licensed contractor or disposed at an approved site. All waste containers are closed to prevent loss overboard.	Low
Deck drainage/bilge water	Washdown from decks entering the sea through drains. Bilge water is containing an oil component.	Mortality of marine organisms, adverse effects on water quality.	Facility has containment zones and bunding in areas where oil products are stored. Oily residues are stored and shipped onshore for disposal. Process bunding has the capacity for at least the volume of the chemical tanks, plus overflows to a main skid bund. Absorbents and containers are available to clean up small accumulations of oil and grease. Minor spills are washed with bio-degradable detergents. Management measures ensure that concentration of OIW discharged to sea does not exceed regulatory requirements. Routine housekeeping/cleanliness inspections are carried out.	Low

3.5.8 Environmental Aspects and Impacts Register

An Environmental Aspects and Impacts Register may be produced at the earliest possible operational stage for a project, site or process, and subsequently developed and updated as the operation progresses. It may use the ENVID as its basis. The purpose of the Register is to capture all environmental aspects (e.g. emissions, discharges, raw material and energy use) in a central inventory, along with their significance; and any controls and actions required to eliminate, reduce or mitigate their associated impacts. ISO 14001 [5] requires organisations to take a systematic approach to identifying aspects and impacts and managing these is arguably the most important component of an EMS.

3.5.9 Best Available Techniques (BAT) Identification

The identification of BAT may occur at the Risk Analysis step, for example during ENVID (see Table 3.2) or later during the Risk Treatment step, where measures to further manage risks/impacts to tolerable levels are identified. It may also occur as a normal part of Engineering Design at the time when equipment and systems are selected for inclusion in a development. In the latter case BAT options may be considered at different design stages, from concept stage through to detailed design, and technical alternatives compared and ranked. BAT studies are typically included as standalone reviews during each of these phases, to evaluate the positives and negatives of technical alternatives by giving due consideration to factors such as [40]:

- Environmental performance;
- Financial cost;
- Safety/working environment/human factors; and
- Regulatory requirements.

The application of BAT is considered part of an organisation's approach to risk management, and this Guidance Document provides further details on the selection of BAT for specific applications and for managing a variety of environmental impacts. Further information on BAT assessment is provided Appendix C.

3.5.10 ALARP Review

ALARP Review is performed at the Risk Treatment step of the Risk Management framework, with the purpose of identifying additional measures that may reduce risk to ALARP. The risk level considered ALARP is where the costs of implementing further risk reduction measures, that go beyond established good industry practice, grossly outweigh the benefits of such measures. A qualitative ALARP Review process may take a similar format to that of ENVID (e.g. a workshop with a team of organisational representatives and industry experts) applying judgement to determine the extent to which further measures to reduce risk are justified on performance, cost, environment and safety grounds. It may also, for more complex issues, be supplemented by a quantitative form of cost-benefit analysis to establish the level at which costs (financial, time, effort, resources, etc.) exceed benefits gained from incrementally reducing risk. ALARP is a key risk management approach recognised in the Offshore Safety Directive [1]. While there is no prescribed method of demonstrating ALARP for environmental risk, similar tenets apply to those for safety risk, for which guidance is accessible in the public domain. Best practice on ALARP involves taking a holistic approach, by subjecting projects and infrastructure to periodic review and update [6]. Guidance already exists in the public domain that may be applied to safety and environmental risk decision making (e.g. [8]).

3.5.11 Asset and Operational Integrity - Safety and Environmentally Critical Elements (SECEs) and Performance Standards

Similar to BAT identification, the process of Safety and Environmentally Critical Elements (SECE) identification occurs as part of the Risk Management framework, typically at the Risk Analysis and Risk Treatment steps

(see above). SECEs ensure continuing operational and asset integrity for offshore facilities. SECEs are critical structures, plant, equipment, and systems, the failure of which could cause or contribute substantially to a major accident and major environmental incident, or for which the purpose is to prevent or limit the effects of a major accident and major environmental incident. SECEs include, for example:

- Structural integrity;
- Well control systems;
- Process containment;
- Fire Detection systems;
- Fire Protection systems;
- Drain Systems;
- Emergency Shutdown systems; and
- Emergency response systems.

SECEs are specifically referenced as a requirement for offshore operations in the Offshore Safety Directive [1]. They are particularly relevant as a risk management approach because they represent key (critical) technical barriers to potentially severe environmental impacts and are also the subject of many additional organisational and operational measures that ensure their continuing performance.

SECE is an adaptation of terminology originally used for Safety Critical Elements (SCEs), to barriers to manage major environmental incidents (MEIs). In practice, environmentally critical elements often overlap with SCEs. It is, however, perfectly possible to identify major accident hazards that do not lead to MEIs either directly or due to the escalation of an event.

Each identified SECE has an associated Performance Standard, demonstrating that the SECE is capable of carrying out its role in terms of functionality, reliability, availability, survivability, and its interdependence on other SECEs. Performance Standards in the offshore hydrocarbons industry are subject to a process of Assurance and Verification, with Verification carried out by a third-party Independent Verification Body that reviews Performance Standards and certifies that they fulfil their specification. An example of the content of a Performance Standard for Hazardous Drains is presented in Table 3.3.

Ongoing asset and operational integrity also rely on planned maintenance and monitoring activities, necessary to ensure not only the ongoing integrity of SECEs [43] but other facility equipment and systems as well. The facility Planned Maintenance System (or similar) is the overarching process used by an organisation to implement asset integrity management during operations. A variety of different approaches are used to verify integrity at operational level. One such example is a System Integration Test (SIT) performed to check that all equipment fits perfectly together, and functions as expected. During the SIT potential failure modes of all critical items (product, system or procedure) are identified and potential corrective actions are established when required.

Industry guidance in this area includes [44,45].

Table 3.3 Illustrative Example Performance Standards – Hazardous Drains

SAFETY AND ENVIRONMENTAL CRITICAL ELEMENT	**Hazardous Drains**	
PURPOSE	The open and closed hazardous drains system safely and quickly drains away leaked hydrocarbons, or other hazardous fluids released on the facility in the event of a spill.	
SCOPE	Closed and hazardous open drains system, including all associated pipework.	
Example Performance Statement(s)	Example Performance Criteria	Example Assurance/ Verification Activities

FUNCTIONALITY What is the specific function required to be performed by the SECE?		
Hazardous drains shall ensure the safe and reliable containment of hydrocarbons for all expected operating conditions.	All hazardous drains and associated piping systems must meet relevant design and construction code criteria, including: Minimum allowable wall thickness. No cracks in piping system. Flanged connections which remain serviceable, aligned and free from damage/scaling. Nuts, bolts, fixings made of correct material/ specification. Criteria for degradation/performance over life.	Planned Maintenance: Visual inspections on a regular basis and any leaks or defects immediately reported. Independent Verification: Hazardous drains are subject to periodic internal and external inspection program and testing, including: Visual examination. Internal metal loss detection. NDT crack/stress detection techniques. Profile radiography.
	Drains must provide a maintenance drain header to collect the maintenance draining of all equipment containing hydrocarbon liquids.	
	Discharge to closed drains is by hard-piped connection that is positively isolated from the process during normal operation. Drain points are fitted with double block and bleed valves (rated for system pressure and above) with an intervening spade or spectacle blind rated for the upstream connection pressure.	
	Hazardous open drains fitted with loop seals to prevent migration of burning liquids to adjacent areas via the drain network.	
All hazardous drains shall be operated within the specified design limits for pressure, temperature and flow.	Systems must not be operated above design pressure, outside of min/max temperature specifications and at higher flow or any other design parameter, unless they have been re-rated due to in- service degradation.	
	Systems must not be operated with failed, inhibited or overridden pressure safety systems in place.	
	No direct link exists between the open and closed drains system, i.e. these are physically separated. Hazardous and non-hazardous open drain systems are segregated by seal loops.	
Example Performance Statement(s)	Example Performance Criteria	Example Assurance/ Verification Activities
RELIABILITY / AVAILABILITY During which times/under which circumstances is the SECE required to perform?		
Hazardous drain system shall maintain continuing integrity such that it may be relied upon during any spill incident.	Hazardous drains must always be available during operations.	
SURVIVABILITY What situations is the SECE expected to survive during normal operations and during/after accident event?		
Hazardous drain system shall survive initial effects of all fire/explosion major accident events.	Hazardous drains must survive initial effects of a major accident but are not expected and not required to survive an escalation or a loss of well control major accident.	
Piping and equipment shall survive dropped object events during normal operations.	Lifting operations over live process equipment must be avoided whenever possible. Dropped object protection fitted to critical process equipment.	Operating Procedures: Lifting activities are controlled through Permit to Work (PTW) and facility lifting procedures.
EXAMPLE DEPENDENCIES/INTERACTIONS WITH OTHER SECEs Which other SECEs does this SECE depend on, or need to interact with, in order to function correctly?		
Example SECE	Relevance	

Topsides Structures	Topsides structures provide primary and secondary support for hazardous drain systems.
Hazardous Material Containment	Drains system piping shares similar Performance Standards to other piping and hydrocarbon containment.
Emergency Shutdown (ESD) System	ESD system protects the hazardous drains system from overpressures.

3.5.12 Barrier Management Strategy

Certain regulatory regimes advocate risk management approaches which apply an overarching "barrier management strategy" that captures not only technical and operational barriers such as safety and environmentally critical elements, but also the organisational barriers that oversee them. The merits of such approaches are that corporate ("organisation-wide") procedures for managing accidents and incidents are included fully in the risk context alongside technical and operational measures. Bowtie diagrams [40] provide a useful illustration of this concept, wherein potential hazard scenarios are characterised in terms of the multiple barriers that are in place both in the lead up to their occurrence (i.e. prevention and detection measures) and those that function to reduce impacts after hazard realisation (i.e. control and mitigation measures). Technical barriers may be active or passive engineering controls, structures and design features. Meanwhile, procedural/operational barriers include measures for which personnel are responsible, such as decision-making processes, tasks performed by a hydrocarbons organisation, and relevant higher-level organisational functions [40].

3.5.13 Spill Contingency Plan

All facilities should have in place a Spill Contingency Plan for the management of a loss of containment of hydrocarbons and/or chemicals leading to a spill onto the facility, or to the surrounding terrestrial (for onshore) or marine (for offshore) environment. For onshore operations, the development of an emergency plan, including spill control measures, is a requirement of the Seveso III Directive [2]. For offshore operations, having the necessary resources in place to effectively respond to a spill is a requirement of the Offshore Safety Directive [1].

Spill Contingency Plan may be referred to as an Oil Pollution Emergency Plan (OPEP), Spill Emergency Plan, etc. in the offshore context. The Plan includes a recognition of spill causes, spill scenarios, as well as facility and wider organisational capability to respond, manage and remediate. A facility should have available both the equipment to effect a first spill response, and personal protective equipment (PPE) for handling spills. Personnel should be trained and competent in first response, and crisis management. All necessary logistics should be in case of a spill event. A typical Spill Contingency Plan may include:

- Description of facilities, project and/or operations;
- Operations control unit strategy (offshore and onshore), including appropriate response capability (equipment, personnel, supporting logistics) in a cascading or tiered structure;
- Oil spill reporting and communication plan, including involvement of authorities and third parties;
- Spill scenarios including information on fluid properties and behaviour, spill size estimation and movement;
- Oil spill response strategy i.e. spill monitoring, decision support for allowing spill to disperse naturally, application of dispersant, etc.;
- Reference to the facility's Well Control Strategy and Response Plan describing blowout hazards/scenarios, and measures for managing these (e.g. relief wells, bull-heading equipment, surface interventions, etc.) [46];

- Safety Data Sheets (SDS);
- For hazardous and noxious substances (HNS), the Plan may make reference to established guidance including from the European Maritime Safety Agency (EMSA) [47] and International Maritime Organisation (IMO) [48];
- Environment and socioeconomic plans developed in accordance with the level of risk; and
- Any relevant indemnity and insurance information as appropriate.

For offshore facilities, spill modelling for hydrocarbons should accompany the Plan and should follow a risk-based approach by integrating environmental parameters (e.g. meteorology, oceanography and hydrology information, type of fluid, and propensity to degradation by natural, physical, chemical and biological forcing) with properties of the substance entering the environment. Depending on the outcome of prior risk assessment on the potential impacts of chemical spills, these may also be included, particularly if operations are occurring in sensitive areas. Spill modelling can offer an assessment on the severity of a spill based on these factors, as well as its likelihood of impacts such as on surrounding marine and terrestrial areas, depending on their environmental sensitivities The Spill Contingency Plan refers to the EIA process in this regard (refer to EIA – Section 3.5.3).

Optimal spill response is heavily reliant on personnel both offshore and onshore understanding their roles and responsibilities and being able to carry these out effectively in the event of an incident. It is therefore important that response planning is accompanied by competency programmes for hydrocarbons organisation personnel to ensure that they are effectively trained on spill prevention, response, and the overall management of any emergency that may be associated with such incidents.

Industry guidance in this area includes [29-31,49-52].

3.5.14 Emissions Management

Emissions management has become a key area of interest for hydrocarbons organisations from a technical, safety, regulatory, and economic standpoint, particularly in terms of reducing methane emissions [53]. An Emissions Management Plan should be prepared for operations that reviews potential emissions arising from activities and sets performance targets for their management (and minimisation).

Flaring, venting and fugitive emissions are widely recognised as a significant source of GHG emissions and air pollution. Methane is a primary constituent of natural gas and is a GHG with global warming potential over 20 times that of carbon dioxide [54]. In terms of environmental impact, flaring is generally preferable to venting (See activities 10 onshore and 3 offshore). Flaring is also preferred from a safety perspective as it removes the potential for unintended gas ignition. In addition, fugitive emissions comprise emissions of hydrocarbons, methane (CH_4) and non-methane volatile organic compounds (NMVOC) other than those released through combustion processes.

Emissions management should include consideration of methods for controlling and reducing methane and carbon dioxide emissions in facility design and operations, and for implementing maintenance initiatives such as leak detection and repair (LDAR) programmes as part of ongoing maintenance [55,56]. Decisions around specific steps may make use of a risk-based approach to determine key sources, their consequences and the subsequent management measures that would deliver the most benefit.

The Emissions Management Plan should provide the technical, commercial and environmental justification for the management of emissions, and should take into account reservoir characteristics including composition of fluids and likely variation over time (e.g. in water, H_2S and gas-to-oil ratios). The level of detail of the Plan should be consistent with facility complexity, and may include the following elements [55,57,58,59]:

- Overarching goals for limiting flaring, venting and fugitive emissions during different operational phases operations, including exploration, appraisal, production and decommissioning;
- Methodology for the assessment of methane, carbon dioxide and other facility emissions including baseload sources and non-routine sources, an estimation of these emissions, and justification for flaring limits requested from the Regulatory Authority through permits and consents;
- Provision for assessment of flaring volumes during design, and reassessment of gas volumes throughout field life such that flaring targets can be continually reviewed and improved upon. For facilities which practice routine flaring, flare gas should be metered [60]. For all facilities, including those which do not practice routine flaring, flare and vent gas should be measured/estimated.
- Consideration of the type of flaring and venting design that provides the best environmental performance, and reduces emissions where possible, together with evidence demonstrating this (see below) [40,61].
- For new facilities, the basis of design should be no routine flaring[6]. For all facilities, continuous flaring and venting for the disposal of associated gas should be avoided where viable alternatives exist. The Emissions Management Plan should include assessment of alternative uses of gas, such as:
  - Use for on-site energy needs;
  - Export to a neighbouring facility or to market;
  - Capture and injection for enhanced oil recovery (EOR); and/or
  - Carbon capture and storage (CCS).
- Where a risk assessment determines the proximity of sensitive environmental receptors, ensure management measures for reducing impacts are considered. This may include minimising impacts to public health/nuisance if local populations are in proximity and should also be considered in the EIA (see below).

Global initiatives such as the Climate and Clean Air Coalition (CCAC) Oil & Gas Methane Partnership (OGMP) support organisations to systematically and responsibly address their methane emissions, and to demonstrate the progress to stakeholders. Indicatively, the OGMP is focused on a group of nine "core" sources of methane emissions as follows [62]:

1. Natural gas driven pneumatic controllers and pumps.
2. Fugitive component and equipment leaks.
3. Centrifugal compressors with "wet" (oil) seals.
4. Reciprocating compressors rod seal/packing vents.
5. Glycol dehydrators.

[6] This may not be possible to achieve in every case, e.g. reservoir uncertainties could materially change associated gas volumes, however it should be the starting point from a design perspective and operators should justify a deviation from this principle.

6. Unstabilised hydrocarbons liquid storage tanks.
7. Well venting for liquids unloading.
8. Well venting/flaring during well completion for hydraulically fractured wells.
9. Casing head gas venting.

This list is currently under development as part of ongoing engagement between organisations within the CCAC OGMP. Minimising methane emissions from upstream hydrocarbons production is also considered as one of five key global GHG mitigation opportunities by the International Energy Agency (IEA) [63,64]. While NMVOC emissions are less critical from a greenhouse gas perspective, reduction of these is important for improving air quality.

Global advances in reduction of carbon dioxide are also supported by a number of initiatives including the World Bank Global Gas Flaring Reduction Partnership (GGFR), which works to increase use of natural gas associated with oil production by helping remove technical and regulatory barriers to flaring reduction, conducting research, disseminating best practices, and developing country-specific gas flaring reduction programmes [65]. Another World Bank initiative is the "Zero Routine Flaring by 2030" initiative, which brings together governments, operators, and development institutions that recognise routine flaring as unsustainable and agree to cooperate to eliminate routine flaring no later than 2030 [66].

3.5.15 Decommissioning Plan

A Decommissioning Plan is a risk management approach describing the measures an organisation proposes to take in connection with the decommissioning and subsequent removal of a facility. It is specifically described here in relation to offshore facilities. Although strictly speaking the term "decommissioning" defines the steps involved in the ending of a facility's active status, in the hydrocarbons industry it is also considered broadly to cover the subsequent management of facility infrastructure, wells and pipelines - either in terms of reuse, removal or (in exceptional cases) leaving in place.

From an environmental management perspective, decommissioning typically covers [67,68]:

- All potential impacts on the marine environment, including exposure of biota to contaminants associated with the facilities, other biological impacts arising from physical effects, conflicts with the conservation of species, with the protection of their habitats, or with mariculture, and interference with other legitimate uses of the sea, both present and future; and
- All other potential environmental impacts, including to final onshore disposal of infrastructure. In cases where a third party is responsible for onshore disposal, it should make reference to disposal requirements onshore.

In principle, the Decommissioning Plan should begin with a "Comparative Assessment", comparing the potential impacts on safety, environment, stakeholders, technical feasibility and cost, in order to select the appropriate decommissioning option, and to ensure management of risks to people (e.g. personnel and other users of the sea) and the environment.

Reuse of infrastructure should be considered prior to decommissioning and may include use by the hydrocarbons industry as well as other sectors [67]. Comparing the potential impacts in terms of safety, environment, stakeholders, technical feasibility and cost will allow selection of the most appropriate decommissioning option, and help to ensure management of risks to people and the environment [67,69]. Leaving infrastructure in place may be prohibited in some cases and permitted in others, the decision around which ultimately rests with the Regulatory Authority and is a function of technical requirements, environmental and safety impacts. The preferred option should, however, be majority facility removal for reuse, recycling, or final disposal [67].

Where the comparative assessment indicates that leaving infrastructure wholly or partly in place ('disposal at sea') may be a preferred option, a proposal should be offered to the Regulatory Authority that explains this assessment and which permits the Regulatory Authority to compare this with other alternatives. It should include a description of [67]:

- Facility characteristics, including any hazardous substances on the facility, method for their removal if required, and expected outcome, as well as contingency plans for any hazards;
- Proposed disposal site including physical, chemical and biological properties and potential facility impacts on the surrounding ecosystem;
- Method and timing of disposal; and
- Environmental monitoring.

An overview on how the Regulatory Authority would normally be expected to carry out an assessment and associated consultations is provided in [67].

Considerations at end of field life may be summarised as follows:

- Well plugging and abandonment, for which there may be requirements to [70-72]:
  - Isolate zones with flow potential penetrated by the well from each other and from the surface unless (cross) flow is tolerable.
  - Secure all annular spaces between casings unless there is no pollution risk such as when the annular space is filled with a non-pollutive fluid (e.g. water-based mud). Formations that belong to different pressure regimes should be separated by one permanent isolation unless cross flow is deemed acceptable.
  - Design barriers which may include for example primary cementation, squeeze cementation, cement plugs, mechanical packers and bridge plugs, and resins, polymers and other types of proven plugging materials also including creeping shales when applicable. Cement is considered the superior material for plugging. Plug lengths may vary depending on bridge plug support, plug material, loggings results and ways of verifying plug integrity e.g. pressure tests, inflow tests, leak tests, etc.
  - Ensure that barriers are designed to withstand changes in reservoir pressure, temperature, mechanical stresses, and corrosive substances, e.g. CO_2, H_2S, brine, etc. Barrier design should also minimise the possible impact of subsidence and all reasonably anticipated geological stresses. Verify the effectiveness of permanent isolation barriers and confirm that isolation integrity meets pre-defined acceptance criteria. Examples of acceptable verification methods include weight testing, pressure testing, inflow testing, cement placement assurance and surface sample testing.
  - Remove wellhead and casings below the seabed to a cutting depth sufficient to prevent conflict with other marine activities. Local conditions such as seabed scouring due to sea current should be considered. In exceptional cases, it may be acceptable to leave or cover the wellhead structure with the approval of the Regulatory Authority. Remove wellhead, conductor and casings using suitable mechanical, abrasive or other effective cutting technology. Inspect the location to ensure no other obstructions related to the drilling and well activities are left behind on the sea floor.
  - Implement a risk-based programme of post-decommissioning monitoring, which may include, for example monitoring fluid seepage at the seawater-sediment interface using specific equipment (e.g. gas chromatography, benthic chamber, lander) with the relevant frequency of observations, and a methodological approach (e.g. Isotope Ratio Mass

Spectroscopy - IRMS). Periodic monitoring should occur until the well is considered permanently plugged with no observed leaks.

- Facility infrastructure operations – Offshore infrastructure may contain hazardous substances that should be comprehensively managed, including inspection, safe packaging for transport, etc. Wells, interconnecting pipelines and processing facilities may contain NORM, heavy metals and organic substances as residual deposits or as scale and waxes. It is hence necessary to be prepared to deal with a variety of substances during well cessation including the potential for pollution. In some cases, the possible presence of contamination may lead to a decision to leave certain infrastructure in-situ. In general, all hazardous material should be removed from the facility if all or part of the facility is to be left in place. The Decommissioning Plan should also consider the best method for topsides removal.
- Drill cuttings pile management – Drill cuttings contaminated with oil-based mud(OBM) or synthetic drilling fluids may bury parts of the facility (e.g. bracings, conductor frame area around legs) and, if relocated or removed, may release of contaminants. Steps required for the management of cuttings include to:
  - Sample the cuttings pile as part of planning for decommissioning, characterising the pile in terms of quantity of cuttings material and the hydrocarbon contamination status, physical properties, size, and other hazardous materials.
  - Perform a comparative cross-functional (e.g. environment, process, marine, safety, cost) assessment, considering the following options:
    - Recovery, onshore treatment and reuse.
    - Recovery, onshore treatment and disposal.
    - Recovery followed by offshore injection.
    - Necessary relocation to adjacent seabed to facilitate removal of jacket.
    - Leave in-situ, bioremediation.
    - Leave in-situ, covering.
    - Leave in-situ, natural degradation.
  - Implement the preferred option according to risk assessment processes included as part of the EIA/ENVID (Sections 3.5.4/3.5.7), Decommissioning Plan (Section 3.5.15), and Engineering Design (Section 3.5.5).
- Management of infrastructure returned to shore – Onshore, the key issues as regards offshore decommissioning relate to the management and disposal of spent materials, particularly hazardous materials. The Waste Hierarchy of reuse, recycling, recovery and disposal applies. This process would normally become the responsibility of a third party.

Consideration should be given to a waste management strategy, which may include elements such as those concerned with the onshore treatment and disposal of waste [73]:

- Identification of waste regulatory requirements, ensuring relevant permits and consents are obtained and requirements cascaded through the supply chain.
- Characterisation and classification of wastes, including hazardous and naturally occurring radioactive material (NORM) wastes, inventories of waste types and volumes, and advice on handling, separation and segregation.
- Development of waste flow models to quantify materials from generation to final destination.

- Ensuring appropriate implementation of Waste Hierarchy Principles [74].
- Track all materials from removal offshore to final destination, creating an auditable data trail facilitating compliance with waste legislation.
- Reuse (for example reuse of stainless steel vessels or storage tanks on other platforms) and recycle (for example recycling of pipework, valves) insofar as possible prior to considering final disposal options.

Offshore decommissioning is discussed in further detail in Section 25 of this Guidance Document.

3.6 References for Section 3

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Part Three: Guidance for Onshore Activities

4. Onshore Activity 1: Site Selection, Characterisation, Design and Construction of Surface Facilities

4.1 Summary of the Activity and the Potential Environmental Impacts

This Section covers site selection and characterisation, primarily concerning assessing a site that has been identified for hydrocarbons exploration/production and prior to the commencement of any extractive activities occurring. In addition, design and construction activities are covered for development activities that may take place at the site. Following the identification of subsurface hydrocarbon resources, the decision to proceed with field development may necessitate planning for surface production facilities. Planning involves site selection/characterisation, which may include performing surveys and modelling to arrive at a concept for hydrocarbons extraction.

Environmental impacts from onshore hydrocarbon operations may include impacts to air, water (surface and subsurface), noise, soil and subsurface geology and biodiversity. There is potential for the modification and/or destruction of species habitat, and the disturbance and displacement of flora and fauna. Noise can emanate from excavation, building, drilling, and (if conducted) fracturing activities as well as vehicle transport. Other possible impacts are land subsidence, if underground pressure diminishes, and the potential for induced seismicity.

Site selection/characterisation, and design/construction of surface facilities considers both planned environmental impacts, i.e. those that are expected to occur (e.g. emissions from construction equipment being used at the site) and unintended environmental impacts, i.e. those that are unexpected and may result from, for example, failure of equipment, incidents or accidents (e.g. spill of hydrocarbons).

Specific examples of where activities may lead to impacts include: removal of soil from the site exposing shallow groundwater aquifers and leading to increased potential for contamination; and inadequate bunding of equipment and storage tanks leading to releases of well site fluids (e.g. drilling muds, flowback and produced water) potentially affecting soil and surface water. Adequate site preparation should attempt to ensure that environmental impacts are minimised throughout the operational life of the project. Planning for construction (e.g. well pads, surface drilling and production facilities) should continually consider ways in which identified environmental impacts could be further reduced.

In Europe, Member States may carry out Strategic Environmental Assessment (SEA) (based on the requirements of the SEA Directive [1]) prior to the release of concession rights for hydrocarbons exploration and production[7]. This assessment is usually carried out by the Regulatory Authority, sometimes in partnership with a hydrocarbons organisation. To an extent, such assessments include screening for key environmental aspects at a particular location prior to giving the go-ahead for industry activities. Approval given by the Regulatory Authority to an organisation for exploration and production activities at a location does not, however, grant authority to carry out any activity. Depending on the nature, location and size of the site

[7] For example, the Strategic Subsurface Plan (Structuurvisie Ondergrond) in the Netherlands which looks at uses of the deep subsurface, including oil and gas, geothermal energy and assesses where areas can be developed.
http://www.commissiemer.nl/advisering/afgerondeadviezen/2907

developed, together with potential for environmental impact, hydrocarbons organisations are still required by the EIA Directive [2] to conduct an assessment at site level (Section 3.5.4).

EIA guidance documents developed in several Member States provide useful guidance on EIA Directive obligations for hydrocarbons organisations [e.g. 3]. Furthermore, some Member States have made EIA decisions for oil and gas projects publicly available, and these constitute an additional source of information for organisations interested in undertaking similar types of operations.

4.2 Best Risk Management Approaches

The best risk management approaches for site selection/characterisation and design/construction of facilities are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for site selection/characterisation, and design/construction including Management of Change (MoC) processes for where new information is brought to light during construction indicating any field conditions that are inconsistent with the results of initial site characterisation/design efforts (Section 3.4.2).
- Ensure that the proposed project is the subject of an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4 and 3.5.7) which considers environmental impacts and suitable measures for their management (e.g. to ecosystems, biodiversity, air and other environmental receptors) [5]. This may include the following elements, depending on whether operations are occurring during exploration and/or production phases:
  - Perform an Environmental Baseline Study [6] (Section 3.5.3) which includes a preliminary risk assessment and the development of a Conceptual Site Model (CSM). This should inform judgment on the significance of any risks and support the design of an appropriate baseline monitoring programme going forward.
  - Where the site will require important on-site road transport, develop a Traffic Management Plan and schedule for the frequency of vehicle movements. The plan should specify speed limits and routes to use, including alternative routes where possible.
  - Evaluate potential for subsidence and induced seismicity, particularly for types of hydrocarbons production for which a risk assessment indicates this may be likely [7]:
    - Undertake an initial risk assessment to identify the hazards and risk mitigation options and to adopt response protocols to be implemented if abnormal seismicity is encountered.
    - Conduct an assessment for risks[8] in relation to potential seismicity on field level for an exploration/production activity and fracturing for shale gas wells. This assessment should form the basis of defining an appropriate monitoring system.
  - Consider potential cumulative, short, medium and long-term impacts of activities on the environment, in the context of the project timescale, proximity to any existing nearby field developments, etc.

[8] For example, see the traffic light approach presented by UKOOG in [7].

- Perform a hydrogeological risk assessment that reviews potential impacts of activities on groundwater and surface water receptors including aquifers; abstraction boreholes (public and private); surface waters fed by groundwater or groundwater-dependent terrestrial ecosystems (such as a wetland areas or sand dunes); groundwater bearing strata, at a greater depth than the aquifers, particularly relevant for unconventional resources; and hydraulic shortcuts between aquifers.
- Produce a Sub-surface Information Plan that evaluates the risk of any fracturing impact on subsurface geology and includes geographical information showing any faults near wells and along well paths, prior to conducting HF activities. The Plan should make use of geomechanical models and should also provide spatial information on likely deposits of waste fluids resulting from the activity. The use of geomechanical models to measure fractures may be considered an emerging technique, for which results from proprietary software still varies widely. Monitoring data (see below) should be used to calibrate and improve models of the site, and to validate stresses, formation pore pressure, and rock mechanical properties. Examples of geomechanical models include Finite Element Modelling (FEM), models based on wireline log data, petrophysical analysis and borehole breakout data calibrated with "mini-frac" tests. Calibration of input parameters so that the models match the results of in situ hydraulic fracture treatment monitoring is practised for optimising hydraulic fracture treatments. This is particularly evident in new plays where little or no pre-existing models or hydraulic fracturing monitoring data are available.
- Produce a Water Resources Plan detailing proposed water sources, taking into account impacts on other local water uses and overall ecosystem requirements. The Plan should include information on proposed final locations for spent water sources (e.g. produced water). Refer also to Onshore Activity 10 (Section 13), 11 (Section 14) and 12 (Section 15).
- Perform a Biodiversity and Ecosystems Assessment to assess potential areas of influence of the project including conducting scoping surveys, baseline data collection and biodiversity and ecosystem study (BES), including the significance of nearby protected areas, presence of threatened species, critical habitats and key ecosystem services [8]. Apply the Mitigation Hierarchy (i.e. avoid, minimise, restore and offset) when considering management of ecosystems and biodiversity as defined by the CSBI [9] (Section 3.5.4).
- Perform an Air Quality Assessment at the site in order to determine the baseline levels of pollution where no such information baseline data exists.
- Perform a Noise Impact Assessment to assess noise and vibration at the site with a description of the measures taken to mitigate this impact, including monitoring.

- For new facilities and modifications to existing facilities, ensure engineering for process design, construction and operation accounts for inherent safety and minimisation of potential for environmental impact (Section 3.5.5) (refer to BAT below).
- Produce a risk-based Monitoring and Sampling Plan [6] detailing monitoring indicators and techniques for the project. This should include provision for monitoring/sampling for:
  - Subsidence [10] and where relevant, induced seismicity. Examples of monitoring systems used in industry include the Site-Specific Monitoring System [6] and the Area of Interest Approach [7].
  - Soil sampling including both surface soils and deeper soil samples from shallow augured holes.
  - Water sampling and analysis for surface and groundwater.

- Air emissions sampling including approaches such as omnidirectional, directional, open-path and fixed-point techniques. Sampling methods and instruments in agreement with Standard Methods should be used wherever possible.
- Radionuclide assessment for NORM depending on whether radionuclides are considered to be present [11,12].
- Noise and vibration monitoring during activities in areas where prior assessment indicates potential disturbance to local populations and/or sensitive ecosystems.
- Ecology monitoring to determine changes in the ecological baseline and the success of mitigation measures.

- When potential emissions and discharges cannot be precisely estimated, a high-level forecast should be included instead noting factors that might influence these (e.g. flow rate, reservoir characteristics). The probability distribution function across industry for specific types of emissions and discharges can support a decision to monitor the emissions or discharges.
- Consider all options in relation to site containment, including:
  - Primary containment – vessels, storage tanks and other facilities within which substances are contained.
  - Secondary containment – bunding, drip trays and other containment barriers designed to collect fluids and substances lost from primary containment.
  - Tertiary containment – arrangements to prevent fluids and substances leaving the site or contaminating the ground, which may include technical, organisational and operational barriers.
- At the end of the field development, conduct a site closure assessment, similar to the baseline study conducted at site characterisation stage in order to review and compare the impacts of the activities over field life and identify necessary remediation.

4.3 Best Available Techniques

The following techniques are considered BAT for Site Selection/Characterisation and Design/Construction:

- Site selection/characterisation:
  - When substantial changes are found to be required to the activities being undertaken on the site, reconsider site characterisation and if necessary supplement with updated data before making changes.
  - Select least environmentally sensitive location for siting facilities and consider selecting sites that may be more easily restored following activities.
  - During site selection, take account of factors including topography, natural drainage and site run-off, and avoid areas prone to flooding and geo-hazards.
  - During site selection, plan activities such that habitat fragmentation and surface disturbance are reduced to the maximum extent possible.
  - Consider the cumulative impacts of hydrocarbons development on local land use, i.e. in the context of any other nearby developments that may also have impacts.
- Design/Construction:

- Include environmental considerations in construction sequencing and staging prior to starting work on site. Consider siting well pads/facilities in order to minimise environmental impacts.
- Where feasible, drill multiple wells from a single well pad (including horizontal and directional drilling when compatible with reservoir characteristics and where no increased risks to the environment are determined) to reduce the number of well pads and the surface area used.
- Fully evaluate wellbore placement and drilling design to account for the specifics of the subsurface site characterisation (refer to Section 4.2) [13].
- Design the site to ensure that infrastructure placement accounts for the possibility of potential accidents/incidents, e.g. siting well drilling equipment at sufficient distance from personnel areas such that these areas would be minimally impacted in the event of a hydrocarbon spill.
- Evaluate the possibility for facilities to be powered fully by electricity from the grid (refer to Section 10), reducing the need for on-site power generation and in turn reducing noise and air emissions.
- Evaluate at design phase the need for sound barriers, blankets and walls to mitigate noise and vibration from activities. Where possible encase equipment (e.g. such as hydraulic pumps, compressors, power generators) with sound enclosures or apply sound reducing barriers around these sources.
- Avoid the construction of new roads where existing roads and infrastructure are suitable for use by site traffic.
- Consider post-project use of infrastructure (e.g. roads), after evaluating potential impacts, with a mind to maximising amenity to local residents.
- Design infrastructure in coordination and cooperation with other hydrocarbons activities where practicable to reduce surface disturbance (flow lines following lease / private roads, use of flow line / pipeline corridors, shared rights of way).
- Design storage, bunding and drainage systems to reduce the likelihood of loss of containment of hydrocarbons and chemicals to the environment (refer also to Sections 5, 6, 7 and 9) for example:
    - Ensuring sufficient and appropriate storage facilities for wastes, including contaminated waste water for example, making sure that the design of mud pits allows for the flexible management of drilling muds.
    - Accounting for atypical conditions such as, for example, heavy rainfall or an elevated water table.
    - Protecting underlying ground and groundwater such as through the use of pavement or impermeable membranes and management of site surface run-off. Examples include laying down site-wide high-density polyethylene resin (HDPE) sheet liner and sufficient cover material to protect against the influx of contaminants from the surface.
    - Drain systems that prevent heavy rainfall from transferring oil and contaminants from the well pad directly to the environment.

- Spill prevention, detection, control and mitigation technologies (i.e. primary, secondary and/or tertiary containment) to protect the site and its immediate surroundings.

4.4 References for Section 4

[1] Directive 2001/42/EC on Strategic Environmental Assessment.

[2] Directive 2014/52/EU of the European Parliament and of the Council of 16 April 2014 amending Directive 2011/92/EU on the assessment of the effects of certain public and private projects on the environment (Environmental Impact Assessment Directive).

[3] UK Environment Agency guidance for EIA for hydrocarbons: https://www.gov.uk/guidance/minerals

[5] API RP 51R Environmental protection for onshore oil and gas production operations and leases – 1st edition – July 2009 – API.

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[12] International Atomic Energy Agency (IAEA), 2003. Extent of Environmental Contamination by Naturally Occurring Radioactive Material (NORM) and Technological Options for Mitigation, Technical Reports Series No. 419.

[13] The Borehole Site and Operations Regulations (BSOR), UK, 1995. http://www.legislation.gov.uk/uksi/1995/2038/made

5. Onshore Activity 2: Handling and Storage of Chemicals

5.1 Summary of the Activity and Potential Environmental Impacts

Handling and storage of chemicals is required for a variety of operations during onshore exploration and production. Operations that make use of chemicals should ensure that these are subsequently collected, re-used, stored as waste, and/or transported off site for treatment and disposal. In some cases, chemicals may be discharged to the environment, typically as a permitted activity[9]. The use of chemicals occurs in the following operations:

- Well drilling, well interventions and completions – Chemicals are used during drilling and well completions and examples (non-exhaustive) include:
  - Cement, used to secure casing in place, and to protect and seal the wellbore.
  - Weighting materials - Increase the density of mud, and balancing formation pressures, as part of well control. Includes barite, hematite, calcite, and ilmenite.
  - Viscosifiers - Increase viscosity of mud to suspend cuttings and weighting materials in drilling mud. Includes bentonite/attapulgite clay, xanthan, carboxymethyl cellulose, and other polymers.
  - Thinners, dispersants, and temperature stability agents - Deflocculate clays to optimise viscosity and gel strength of drilling mud. Includes tannins, polyphosphates, lignite, and lignosulfonates.
  - Flocculants - Increase viscosity and gel strength of clays or clarify or de-water low-solids drilling muds. Includes inorganic salts, hydrated lime, gypsum, sodium carbonate and bicarbonate, sodium tetraphosphate, and acrylamide-based polymers.
  - Filtrate reducers - Decrease fluid loss to the formation through the filter cake on the wellbore wall. Includes bentonite clay, lignite, sodium-carboxymethyl cellulose, polyacrylate, and starch.
  - Alkalinity, pH control additives - Optimise pH and alkalinity of drilling mud, controlling drilling mud properties. Includes lime (CaO), caustic soda (NaOH), soda ash (Na_2CO_3), sodium bicarbonate ($NaHCO_3$), and other bases as well as acids.
  - Lost circulation materials - Plug leaks in the well bore wall, preventing loss of drilling mud to the formation. Includes natural fibrous materials, inorganic solids, and inert insoluble solids.
  - Lubricants - Reduce torque and drag on the drill string and rotating machinery. Includes oils, synthetic liquids, graphite, surfactants, glycols, and glycerine.
  - Shale control materials - Control hydration of shales that causes swelling and dispersion of shale, collapsing the wellbore wall. Includes soluble calcium and potassium salts, other inorganic salts, and organics such as glycols.

[9] Produced water discharge represents a planned discharge of chemicals and is covered in Onshore Activity 12.

- Emulsifiers and surfactants - Facilitate formation of stable dispersion of insoluble liquids in water phase of drilling mud. Includes anionic, cationic, or non-ionic detergents, soaps, organic acids, and water-based detergents.
- Bactericides and other biocides - Prevent biodegradation of organic additives. Includes glutaraldehyde, THPS and others.
- Defoamers - Reduce mud foaming. Includes alcohols, silicones, aluminium stearate ($C_{54}H_{105}AlO_6$), and alkyl phosphates.
- Pipe-freeing agents - Prevent pipe from sticking in wellbore or used to free stuck pipe. Includes detergents, soaps, oils, and surfactants.
- Calcium reducers - Counteract effects of calcium from cement, formation anhydrites, and gypsum on mud properties. Includes sodium carbonate and bicarbonate (Na_2CO_3 and $NaHCO_3$), sodium hydroxide (NaOH), and polyphosphates.
- Corrosion inhibitors - Prevent corrosion of drill string by formation acids and acid gases. Includes amines, phosphates, and other specialty mixtures.
- Temperature stability agents - Increase stability of mud dispersions, emulsion and rheological properties at high temperatures. Includes acrylic or sulfonated polymers or copolymers, lignite, lignosulfonate, and tannins.
- Drilling muds and well completion fluids supplemented with chemical additives such as corrosion inhibitor, biocide, oxygen scavenger, acids, glycol, weighting materials, salt, viscosifier, etc.

- Production – Chemicals are used in a variety of applications during production. They may for example be injected into the process stream, used as pipeline chemicals, gas treatment or utility chemicals, as well as being added to export flow or arriving from upstream facilities. These chemicals include:
  - Corrosion inhibitors - Prevent corrosion of process equipment and pipework by formation acids and acid gases. Includes amines, phosphates, and other specialty mixtures.
  - Scale inhibitors - Prevent formation of scale from blocking/hindering fluid flow through pipelines, valves, and pumps. Includes acrylic acid polymers, maleic acid polymers and phosphonates.
  - Demulsifiers – Break crude oil emulsion into oil and water phases. Includes xylene, heavy aromatic naphtha (HAN), isopropanol, methanol, 2-Ethylhexanol and diesel.
  - Biocides – Prevent microbiologically influenced corrosion for example in crude rundown and slops tanks. Includes antibacterial, antifungal and anti-algae formulations.
  - Dehydration chemicals – Prevent corrosion and free-water accumulation. Includes monoethylene glycol (MEG), diethylene glycol.(DEG), triethylene glycol (TEG) and hydrate prevention chemicals (e.g. methanol).
- Hydraulic fracturing – Chemicals are used in hydraulic fracturing processes, e.g. as substances in fracturing fluids [1]. These include, for example [2]:
  - Proppants – Keep formation fractures open to allow gas/fluid to flow more freely to the well bore. Includes silica, quartz sand (sintered bauxite, zirconium oxide, and ceramic beads).
  - Acids – Clear the production casing by removing cement, drilling mud and drilling debris from casing perforations prior to fracturing fluid injection. Includes hydrochloric acid, formic acid, acetic acid.

  - Biocides – Prevent microbial growth from occurring downhole which could restrict flow from the created hydraulic fracture network. Includes glutaraldehyde, quaternary ammonium chloride and various others.
  - Clay stabilisers – Prevent swelling, shifting and migration of water sensitive clay minerals, which could block pore spaces and therefore reduce permeability. Includes potassium chloride, sodium chloride, tetramethyl ammonium chloride (TMAC), and choline chloride.
- Enhanced recovery – chemicals used in enhanced recovery techniques, to further increase production, including thermal recovery, gas or the injection of chemicals (including polymers).
- Day to day operations (covering multiple phases) – Chemicals are loaded, stored and handled for daily requirements and specific operations in both drilling and production phases. Examples include hydraulic fluid, chemicals used for maintenance, detergents, etc.

The use of chemicals has potential to pose risks to the environment in relation to planned discharges and unintended releases, both of which can lead to disturbance of terrestrial species and/or potential contamination of the soil surface, deeper soil layer, surface waters, groundwater aquifers and the atmosphere.

Unintended releases of chemicals could for example occur during the following operations:

- Loss of containment from storage or handling of chemicals (and chemical waste) to point of use (e.g. from pipework, chemical tank);
- Loss of containment during drilling/completions (e.g. loss of well control, drilling mud spill, etc.); or
- Spillages during routine day to day operations.

REACH Regulation 1907/2006 [3] requires the operator using a chemical substance either on its own or in a mixture, to ensure its safe use on site. The facility should retain an (extended) Safety Data Sheet (SDS) or equivalent information for each chemical held, with exposure scenarios containing operational conditions and risk management measures for safe use, and to facilitate the training of workers in the relevant risk assessment procedures (where such an eSDS is available). REACH is directly linked to the CLP Regulation 1272/2008 [4] which establishes hazard and precautionary statements.

For facilities where HVHF takes place, compliance is required with EC Recommendation 2014/70/EU [5].

The difference in duration of the exploration compared to the production phase of onshore operations, might have an influence on the measures and techniques selected to manage risks in relation to chemicals. Whereas permanent solutions are applied during production phases, more temporary solutions may be applied during exploration phases. Both are, however, expected to manage risk with a similarly high level of rigour.

5.2 Best Risk Management Approaches

The best risk management approaches for the handling and storage of chemicals are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for chemicals handling and storage (Section 3.4.2).
- Ensure that chemical handling and storage during operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).

- Consider alternative approaches to the use of chemicals classified as hazardous according to the CLP Regulation [4], wherever technically feasible and sound from a health, safety and environmental perspective. Such alternative approaches may result in either the elimination of hazardous chemical substances or possible substitution with less harmful alternatives (lowest potential environmental and health risks).
- Consider options for re-use of chemicals (e.g. drilling muds).
- Assess at an early stage the proposed chemicals for use and avoid use of chemicals which may be hazardous to groundwater. Avoid the use of oil-based drilling muds, at least until the well has been sealed to prevent any ingress of chemicals to groundwater aquifers.
- Ensure the implementation of REACH [3] requirements, core components of which consist of:
  - Ensure registration requirements under REACH [3] are fulfilled (where relevant) and that operations that will take place at the facility are covered by the registration or "downstream user report". This should include the following, specific to the facility in question:
    - Hazard identification, i.e. identification of the capacity of a substance to cause adverse effects.
    - Concentration-effect assessment, i.e. estimation of the relationship between the level of exposure to a substance and the incidence and severity of its effects.
    - Exposure assessment, i.e. estimation of concentrations or doses to which environmental compartments may be exposed.
    - Risk characterisation, i.e. estimation of incidence and severity of the adverse effects likely to occur.
    - Risk estimation, i.e. quantification of the estimated likelihood in a risk characterisation.
  - Ensure compliance with specified risk management measures and operational conditions within SDSs where available; these may also be set out within relevant 'generic exposure scenarios' such as in [6] where suppliers do not provide SDSs or specific exposure scenarios.
  - Ensure compliance with any requirements for authorisation of substances of very high concern (SVHC) - i.e. carcinogenic, mutagenic or toxic to reproduction (CMRs); persistent, bio-accumulative and toxic (PBTs); very persistent and bio-accumulative (vPvBs); [3], and with any restrictions relating to these under REACH.
- Ensure that biocides used are authorised under the EU Biocides Regulation 528/2012 (EU BPR) [7] and that use at the facility follows safety instructions and any provisions stated in the biocidal product authorisation.
- For new facilities and modifications to existing facilities, ensure engineering design for chemical handling and storage accounts for inherent safety and minimisation of potential for environmental impact in the event of either a planned or unintended release (refer to BAT below) (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Consider options for site containment and have in place a Spill Contingency Plan that includes information on management of spills of chemicals to the environment (Section 3.5.13).

- Undertake a risk assessment and classification exercise that determines the class of containment required (i.e. primary, secondary and tertiary) on the basis of that assessment at each life-cycle phase of the onshore operations; and consider the containment options for each class of containment. Examples of containment measures and techniques are described in [8-10].

5.3 Best Available Techniques

The following techniques are considered BAT for the handling and storage of chemicals [8,11]:

5.3.1 Design

- Consider as part of early design the necessary system capacity for storing chemicals on site.
- Ensure storage facilities are designed and constructed so that the contents are effectively contained.
- Install non-return valves at chemical injection points in hydrocarbon production process systems.
- Ensure the design pressure of chemical injection pumps is the same as the system into which they inject.
- Define containment barriers in relation to possible leaks, incidents and accidents. Examples include bunded areas with adequate drainage for storage and emptying of transportable tank containers.
- Locate storage for incompatible chemicals in separate bunds.
- Ensure piping from transportable tank containers to permanent storage tanks or other facilities is self-draining.
- Provide possibility to securely fix transportable tank containers in the bunded area.
- Protect permanent piping installations and hose couplings against damage from handling operations.
- Provide a separate drain to a chemical spill tank from the chemical injection package/system.
- Ensure dropped object protection on critical structures and equipment including in chemical tank areas and above pipework.
- Design to minimise risk of spills (e.g. breakage of sacks) and facilitate collection of spills.
- Wherever practicable, design the transfer system between transport and storage tanks to be a closed system which allows the complete draining of transfer tanks. Unique couplings should be used on transfer systems in order to reduce risk of unintentional transfer to a wrong tank.

5.3.2 Operations

- For each chemical used, maintain the amounts, trade names, major hazardous components and toxicity information both at the facility and at another location, through a centrally held "live" database (i.e. kept continually up-to-date).
- Ensure chemical storage procedures specify that chemicals and chemical waste is stored in separate, labelled containers/drums.

- Ensure that chemical spill response and containment equipment is routinely inspected, maintained, and operationally exercised and tested, is deployed or available as necessary for response.
- Document and report all spills, as well as near misses. Following a spill or near miss with potential for significant environmental impact, carry out a root cause investigation and undertake corrective actions to prevent recurrence.
- Maintain storage facilities in accordance with manufacturer guidance and regulatory requirements (e.g. on frequency of maintenance) and retain records of such maintenance.
- Inspect storage facilities in order to identify any potential structural flaws or leaks, as well as ensuring security of these facilities.
- For spills of hazardous materials that cannot be recycled on site, collect for transportation for recycling and disposal at an approved facility.
- Ensure that the materials of the storage facilities are not damaged by the contents and are not liable to form hazardous compounds with the contents.
- Ensure that any fastenings are strong and solid throughout to ensure that they will not loosen.
- Ensure that storage facilities fitted with replaceable fastening devices are properly designed to allow repeated refastening without the contents escaping. Additional guidance for this activity may be found in references [12-15].

5.4 References for Section 5

[1] UKOOG, 2015. UK Onshore Shale Gas Well Guidelines. http://www.ukoog.org.uk/images/ukoog/pdfs/ShaleGasWellGuidelinesIssue3.pdf

[2] JRC, 2013. Assessment of the use of substances in hydraulic fracturing of shale gas reservoirs under REACH. http://publications.jrc.ec.europa.eu/repository/bitstream/111111111/29386/1/req_jrc83512_assessment_use_substances_hydraulic_fracturing_shale_gas_reach.pdf

[3] Regulation (EC) No 1907/2006 concerning Registration, Evaluation, Authorisation and Restriction of Chemical substances (REACH).

[4] Regulation (EC) No 1272/2008 of the European Parliament and of the Council of 16 December 2008 on classification, labelling and packaging of substances and mixtures (CLP Regulations).

[5] Commission Recommendation of 22 January 2014 on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (2014/70/EU).

[6] IOGP, 2016. Generic exposure scenario for the use of chemicals in the exploration and production of hydrocarbons using high-volume hydraulic fracturing, IOGP, Cefic and EOSCA, April 2016, Report 553.

[7] Regulation (EU) No 528/2012 concerning the making available on the market and use of biocidal products (EU BPR).

[8] CIRIA, 2014. Containment systems for the prevention of pollution (C736) – secondary, tertiary and other measures for industrial and commercial premises. http://www.ciria.org/Resources/Free_publications/c736.aspx

[9] European Commission, 2006. Reference Document on Best Available Techniques on Emissions from Storage. http://eippcb.jrc.ec.europa.eu/reference/BREF/esb_bref_0706.pdf

[10] PGS 15, 2016. Opslag van verpakte gevaarlijke stiffen (NL). http://www.publicatiereeksgevaarlijkestoffen.nl/publicaties/PGS15.html

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[12] Nederlandse Richtlijn Bodembescherming (NRB), 2012 (Netherlands Soil Protection Guidelines).

[13] IPIECA/OGP, 2009. Drilling fluids and health risk management - A guide for drilling personnel managers and health professionals in the oil and gas industry. http://www.ipieca.org/resources/good-practice/drilling-fluids-and-health-risk-management/

[14] ENFORM, 2012. Controlling chemical hazards in the oil and gas industry: program development guideline. The Safety Association for Canada's Upstream Oil and Gas Industry. http://www.energysafetycanada.com/files/pdf/publications/51609-792845.guidelinecch2012binder.pdf?page=24

[15] ECHA, 2017. Guidance on labelling and packaging in accordance with Regulation (EC) No 1272/2008. https://echa.europa.eu/documents/10162/23036412/clp_labelling_en.pdf/89628d94-573a-4024-86cc-0b4052a74d65

6. Onshore Activity 3: Handling and Storage of Hydrocarbons

6.1 Summary of the Activity and Potential Environmental Impacts

The handling and storage of hydrocarbons – both oil and gas – occurs onshore during the exploration and production phases as part of operations as diverse as:

- Well drilling and completion – During exploration and development, hydrocarbons from a reservoir may circulate to the surface as part of the drilling process.
- Production – Hydrocarbons are extracted from the reservoir via the well for processing, storage and transport. During production, hydrocarbons are handled and stored in a variety of ways within process plant, equipment and pipework until the time at which they are finally transferred off site.
- Day to day operations – Hydrocarbons are stored and handled for daily requirements and specific operations. Examples include diesel (e.g. generators, pumps, etc.) and liquid petroleum gas (LPG).

During any one of the above described operations, there is potential for a loss of containment or "release" whereby hydrocarbons enter the environment. This may occur at a facility (e.g. a release from process equipment) or away from it (e.g. a loss of containment from the well). Hydrocarbon releases can vary in size from small volume leaks (e.g. from storage tanks, pumps, hoses, valves or flanges) to very large spills.

This Section covers only unintended releases of liquid hydrocarbons. Planned operations should never result in liquid hydrocarbon discharges to the environment without treatment having first been considered. However, discharges may be considered as part of a number of different activities including for produced water (Onshore Activity 12 - Section 15), hydrotesting and well completions (Onshore Activity 5 – Section 8) and HF activities, where applicable (Onshore Activity 6 – Section 9). Transport of hydrocarbons off site is outside the scope of the Guidance Document.

Unintended releases of hydrocarbons may result from, for example, failure of equipment, human error, incidents or accidents. Hydrocarbons released into the environment have the potential to pose significant impacts upon surrounding ecosystems including to soils, surface waters and groundwater, and through disturbance and contamination to species and their habitats.

In terms of managing risk, unintended hydrocarbon releases are typically considered in terms of both their safety and environmental consequences, and hence most of the existing regulations and guidance for safety risk management are also applicable to environmental risk. The Seveso III Directive (2012/18/EU) [1] deals with onshore major accident hazards involving dangerous substances, covering establishments where dangerous substances may be present in quantities exceeding certain thresholds (e.g. for crude oil or condensate from gas extraction).

6.2 Best Risk Management Approaches

The best risk management approaches for the handling and storage of hydrocarbons are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels and contains procedures for hydrocarbon storage and handling (Section 3.4.2).

- Ensure that the management of hydrocarbon storage and handling during operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- For new facilities and modifications to existing facilities, ensure engineering design for handling and storage of hydrocarbons accounts for safety and minimisation of potential for environmental impact in the event of an unintended release (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Have in place a Spill Contingency Plan for the management of spills of hydrocarbons to the environment (Section 3.5.13). Relevant guidance such as [2] should be taken into account.
- Implement additional approaches as considered necessary to manage risks of planned and unintended releases for specific operations to ALARP, including:
  - For well design, construction and drilling/completion operations, undertake risk assessments to identify reservoir and well integrity risks, and ensure that these are either eliminated or reduced to acceptable levels [3-6]. Risk assessments should include:
    - An assessment of subsurface conditions and identification of potential environmental hazards using the professional judgement of technical experts and appropriate technical studies, e.g. HAZID/ENVID (Section 3.5.6). All identified risks should be recorded, for example in a risk register, and mitigation measures specified.
    - A review of risks and measures to manage these to ALARP (Section 3.5.10), performed by suitably qualified company personnel, with input from the Regulatory Authority as appropriate. The review should also include, as appropriate, technical experts with an understanding of well design, construction and drilling/completions. The objectives of the review include [5]:
      - Substantiation of the well integrity aspects of the well design, and reviewing and endorsing the well integrity related aspects of the planned operations.
      - Validation of the pore pressure / fracture gradient estimate.
      - Reviewing risks associated with drilling and completion operations and providing oversight for implementing measures to manage these, e.g. for well blowout this would include primary/secondary well control barriers.
  - For well testing, undertake a risk assessment covering the following aspects:
    - Criteria for the success and failure of a test.
    - Contingency plans if the well cannot be successfully tested as required.
    - Operational aspects including protection of personnel, personnel competence, etc.
    - Hazards of fluid released if a barrier fails, including fluids released to atmosphere, potential for escalation, etc.
    - Securing pipework and equipment used in test, including temporary pipework service and rating.

- Temporary storage and transport of produced hydrocarbons on site.

- During production, perform ongoing well integrity reviews throughout the operational lifecycle to select, install, verify, test, maintain and repair suitable barriers, and to consider:
  - Maximum differential pressure across the barrier throughout the well life cycle[10].
  - Fluids to which the barrier could be exposed (hydrocarbon gas, H_2S, CO_2, etc).
  - Consideration of the consequences if a barrier fails and exposes another part of the well to higher pressure than it was designed to contain.
  - Consideration of the degradation of the full barrier-envelope over time.
  - Contingency and emergency response during design, e.g. relief well planning.
- During production, implement ongoing asset integrity programmes to ensure integrity of all plant and equipment (Section 3.5.11)

6.3 Best Available Techniques

The following techniques are considered BAT for the handling and storage of hydrocarbons [5-12]:

6.3.1 Design

- For well design, provide at least two barriers to the formation, as per industry and design engineering practices. Barriers may be active barriers such as the Christmas Tree and wellhead; and potential barriers such as the blow-out preventer (BOP) [13]. Well operations that are performed with fewer than two barriers available require careful consideration by the well-operator and Regulatory Authority to demonstrate that the risks are managed to an acceptable level.
- For facilities design, ensure the following:
  - Design leak detection systems (such as telemetry systems or pressure sensors) that are fit for purpose, and in accordance with the result of the risk assessment.
  - Ensure adequate integrity for the lifetime of the facility of control and prevention systems in all pipelines, process equipment, and tanks (for example suitable pipeline material and wall thickness, corrosion coupons and inhibitor dosage system).
  - Specify appropriate storage, e.g. double skinned tanks, floating roof storage tanks equipped with high efficiency seals or a fixed roof tank connected to a vapour recovery system [12].
  - Design storage vessels for hydrocarbons fitted with level detection and an overfill protection system. They should be protected against over or under pressurisation.
  - Design containment bunds around vessels and tanks to contain accidental releases. Bunds should contain the contents of the inventory that can be released in a single incident [14][11].

[10] Note that well testing may in itself pose a risk in the case of high pressure, high temperature (HPHT) wells.

[11] In this context, it is suggested that the minimum capacity of the bund should be 110% of the capacity of a single tank. Where two or more tanks are installed within the same bund, the recommended capacity of the bund is the greater of either 110% of the capacity of

Spillage from vessels other than storage tanks should be contained by paved or otherwise, impermeable areas and collected through the open drain systems.

- Ensure that ancillary equipment associated with storage vessels such as pumps, oil bath heaters and filters are installed in a containment bund.
- Ensure that fluid pipework joints are included inside the containment bund or, and where this is not possible, is protected by an impermeable membrane.
- Design and install shutdown valves to allow early shutdown or isolation in the event of a spill.
- Develop automatic shutdown actions through an emergency shutdown system for significant spill scenarios so that the facility may be rapidly brought into a safe condition.
- Minimise the number of flanges and connectors in design and replace with welded connections where possible. Specify improved flanges (for facilities with a high potential for environmental pollution, flanges with tongue and groove or with projection and recess, or special seals such as those with metal or grooved seals, are common practice).
- Install all flanged connections in liquid tight pits making them accessible from the surface.
- Optimise the selection and requirement for maintenance of gaskets during the design phase.
- For piping, specify aboveground closed piping in new facilities. For existing facilities apply a risk and reliability-based maintenance approach.

6.3.2 Operations

- In order to ensure control of facilities under all conditions, test the automatic shutdown system on a regular basis to ensure that it functions correctly.
- Perform ongoing periodic reviews of storage needs during the lifetime of the operation.
- Ensure that containment equipment is routinely inspected, maintained, operationally exercised and tested.
- Prioritise inspection and maintenance of SECEs, to ensure all essential safety barriers are operational and to minimise maintenance backlog.
- Execute, in addition to normal inspections, assurance activities such as 'Process Safety Reviews' and 'Hardware Barrier Assessments' (Sections 3.5.6 and 3.5.12).

6.4 References for Section 6

[1] Directive 2012/18/EU of the European Parliament and of the Council of 4 July 2012 on the control of major-accident hazards involving dangerous substances (Seveso III Directive).

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the largest tank within the bund or 25% of the total capacity of all the tanks within the bund, except where tanks are hydraulically linked in which case they should be treated as if they were a single tank [11].

[2] IPIECA, 2015. Tiered preparedness and response: Good practice guidelines for using the tiered preparedness and response framework.

[3] International Standards Organisation (ISO), 2015. ISO 31000:2009 – Risk Management.

[4] NOGEPA, 2016. Well Engineering and Construction Process. Industry Standard 41.

[5] Oil & Gas UK, 2016. Well Life Cycle Integrity Guidelines. Issue 3, March 2016 (OP119). https://oilandgasuk.co.uk/product/well-life-cycle-integrity-guidelines-issue-3-march-2016/

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[8] NOGEPA, 2016. Operational Barriers for Well Integrity. Industry Standard 51.

[9] England Environment Agency, 2016. Onshore Oil & Gas Sector Guidance.

[10] World Bank / IFC, 2017. Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development, Draft Revised Version.

[11] European Commission, 2006. Reference Document on Best Available Techniques on Emissions from Storage. http://eippcb.jrc.ec.europa.eu/reference/BREF/esb_bref_0706.pdf

[12] European Commission, 2015. BAT Reference Document (BREF) for the Refining of Mineral Oil and Gas. http://eippcb.jrc.ec.europa.eu/reference/BREF/REF_BREF_2015.pdf

[13] International Standards Organisation (ISO), 2017. ISO 16530-1:2017, Petroleum and natural gas industries -- Well integrity -- Part 1: Life cycle governance.

[14] CIRIA, Containment systems for the prevention of pollution (C736) – secondary, tertiary and other measures for industrial and commercial premises, CIRIA C736, 2014.

7. Onshore Activity 4: Handling of Drill Cuttings and Drilling Muds

7.1 Summary of the Activity and Potential Environmental Impacts

Drilling of hydrocarbon wells generates drill cuttings, which are particles of crushed rock produced by the action of the drill bit as it penetrates the earth. The chemical and mineral composition of drill cuttings reflects that of the rock layers being penetrated by the drill. Also used as part of the drilling process are drilling fluids (or muds), which serve multiple purposes including to carry drill cuttings to the surface, to lubricate and cool the drill bit, and to control well pressures as part of safe drilling operations.

Drilling fluids are liquid mixtures of fine-grained solids, inorganic salts, and organic compounds dissolved or dispersed/suspended in a 'continuous phase' (the base fluid) which may be water or an organic liquid. Classification of drilling fluids is based on the primary component of the continuous phase (water, oil or synthetic hydrocarbons) [1]:

- Water-based drilling fluids (WBDFs) are formulated mixtures of clays, natural and synthetic organic polymers, mineral weighting agents, and other additives dissolved or suspended in fresh water, or brine. WBDFs (or "water-based muds") are the most widely used, are generally less expensive than other systems and are the preferred option from an environmental perspective, although they are not necessarily suitable for all formations (see below);
- Non-aqueous drilling fluids (NADF) are emulsions in which the continuous phase is an organic base fluid ("oil-based muds" or "synthetic based muds"), with water and chemicals as the internal phase. Water, containing inorganic salt and oil-soluble or oil dispersible additives is dispersed into the non-aqueous continuous phase and the resulting emulsion is stabilised with emulsifier; and
- Onshore, pneumatic fluid systems (air, mist, foam, gas) are implemented in areas where formation pressures are relatively low, and the risk of lost circulation or formation damage is relatively high. Pneumatic fluid systems use compressed air or gas instead of liquids to circulate cuttings out of the wellbore.

The choice of water or oil/synthetic-based muds is dependent on the technical characteristics of a well drilling operation. Use of mud with suitable properties ensures that a safe drilling margin is maintained whereby mud properties (e.g. weight) are capable of controlling pore pressure and formation fluids while not fracturing the formation, thus maintaining well control. The use of oil-based muds is sometimes preferred for drilling through production zones containing hydrocarbons, and for technically challenging situations, including:

- Demanding drilling operations, including highly deviated, extended reach, and horizontal wells;
- Where higher lubrication and lower friction are required than is typically offered by water-based muds;
- To enable drilling through rock that would otherwise swell and disperse in water based mud (e.g. clays);
- To facilitate deeper drilling in high-temperature environments that would dehydrate water-based drilling muds and impact hole stability; and
- To enable drilling through water-soluble geologies.

These aspects and the selection of drilling muds should be considered as part of a Conceptual Site Model (CSM), when taking into account site characteristics (Section 4).

Onshore, the key environmental issues relating to the handling of drill cuttings and drilling muds are ensuring that these are neither unintentionally released, nor incorrectly disposed of. This Section considers the operational handling of drill cuttings and drilling muds, including their management up to and including the point of final disposal. It does not consider unintended releases of drill cuttings and drilling mud to the environment – such releases are considered as a release of hydrocarbons and/or chemicals under Onshore Activities 5 and 6. It should be borne in mind that the scale of operations involving the management of mud and cuttings varies considerably across sites, ranging in size from single wells to those with multiple wells/well-pads covering potentially hundreds of individual wells.

Drill cuttings become contaminated with both the residues of drilling muds and hydrocarbons from the well, and other potential contaminants e.g. reservoir heavy metals and/or NORM. In addition, they also contain chemicals used during the drilling and well completion processes. Drill cuttings should be collected during drilling and treated to remove contaminants prior to final disposal. Inappropriate storage of contaminated drill cuttings on site can generate surface runoff that, if inappropriately managed, may lead to contaminants such as chemicals, additives and hydrocarbons being released into groundwater through long-term leaching.

7.2 Best Risk Management Approaches

The best risk management approaches for the handling of drill cuttings and drilling muds are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for handling of drill cuttings/muds (Section 3.4.2).
- Ensure engineering design for handling of drill cuttings/muds accounts for inherent safety and minimisation of potential for environmental impact and exposure to hazardous materials in the event of either a planned or unintended release (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Establish an Environmental Baseline (Section 3.5.3) [2] including a programme of groundwater and soil sampling prior to drilling, and perform analysis relating to the zone of potential contamination, in case this should be required for future reference.
- Ensure that the handling of drill cuttings and drilling muds during onshore operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7), including:
  - Estimate intended generation of drilling mud and cuttings in terms of type, location and quantity expected.
  - Assess drilling muds based on their properties (chemical additive concentration, toxicity, bioavailability and bioaccumulation potential) and the receiving environment, and characterise drill cuttings to arrive at an understanding of environmental risk.
  - Develop and select drilling muds (WBFs, NADFs, pneumatic fluid systems) in a manner which ensures safety of the well and minimises losses and gains of mud, taking into account the filter cake design, inclusion of non-hazardous lost-circulation materials, appropriate mud weights and the interaction of the mud with the rock formations that are being drilled [3].

  - Select an appropriate waste management option in line with Waste Hierarchy Principles [4]: to Prevent, Reuse, Recycle, Recover and as a last resort Dispose of produced waste. Water based muds are to be preferred to oil-based muds due to their lower cost and relative ease with which water-based muds can be decontaminated prior to disposal. The maximum fraction of mud on drill cuttings should be evaluated taking into account the selected waste management option.
- Implement additional approaches as considered necessary to manage risks for specific operations, including:
  - Select the appropriate drilling mud for the required application, avoiding the use of oil-based muds where possible. If not possible, only use oil-based muds that are of a sufficiently low toxicity and only after the hydrocarbons organisation has been issued a permit by the Regulatory Authority when it has verified such low toxicity.
  - Do not use any oil-based muds when drilling through shallow soils or local freshwater aquifers, water-based or pneumatic drilling muds should be used.
  - Do not dispose of drilling muds or cuttings onto land ("land spreading").
  - Do not use diesel oil-based muds.

7.3 Best Available Techniques

The following techniques are considered BAT for the handling of drill cuttings and drilling muds [1,3,7-11]:

- Separate drill cuttings from the drilling muds by means of liquid/solid control techniques (e.g. shale shakers or equivalent).
- Perform pre-mixing and preparation of drilling muds in centralised mud fluid facilities to reduce the risk of unintended releases of chemicals at the well site.
- Recondition and treat used muds where practicable for reuse, recycling, temporary storage or disposal.
- Use a closed loop solids-control system when drilling with oil-based muds, such that mud passes through the equipment (e.g. shale shaker, de-sander / de-silter, centrifuge) and is recirculated in the well.
- Use a partially closed loop solids-control system when drilling with water-based muds, such that continuous fluid level management is facilitated.
- Use a mud management system to monitor for any losses or gains.
- After applying a solid/liquid control of the drill cuttings (e.g. shale shaker, de-sander / de-silter, centrifuge), apply a secondary treatment of contaminated drill cuttings to help reduce hydrocarbon concentrations, using one or a combination of the following techniques:
  - Mechanical cuttings dryer – used to further separate drilling mud from drill cuttings, which improves recovery of the drilling mud and reduces the concentration of base fluid retained on cuttings (BFROC). The following types of cuttings dryers are usually available: centrifugal cuttings dryer and vacuum cuttings dryer.
  - Thermal treatment – thermal desorption is primarily used to separate hydrocarbons from cuttings drilled with NADF. Most thermal desorption systems used are indirect (where heat is generated separately from the desorption chamber) or friction-based systems. The technique includes systems working at temperatures from 250°C to 350°C that allow for the

recovery of hydrocarbons and water from wastes as well as low temperature systems, which may be sufficient to treat wastes with light oils.

- Biological treatment – bioremediation of drill cuttings in treatment cells or by in-vessel composting is a controlled biological treatment process whereby organic matter is decontaminated by causing the biological oxidation of organic substances contained in drilling wastes in controlled conditions within a vessel. A high salt content may negatively affect the microbial activity.

- Select and apply an appropriate end-of-life solution for drill cuttings that minimises the final impact of this material on the terrestrial environment. Such a solution should follow the waste hierarchy of reuse, recycling, disposal which could include, for example:
  - Reuse and recycling - Use in construction materials has potential benefits in substituting for virgin materials and reducing the need for disposal or further treatment, providing it can be ensured that materials do not leach contaminants. Use as cement kiln feedstock has potential environmental benefits in replacing virgin feedstock and fuel. Reuse may require pre-treatment to meet applicable regulatory specifications.
  - Controlled incineration - For cuttings contaminated with NADF, at a licensed and authorised hazardous waste installation.
  - Disposal to landfill - the least preferred option for end-of life handling of drill cuttings after other methods have been exhausted is disposal at a licensed and authorised landfill site. Untreated drill cuttings containing NADF constitutes hazardous waste, which when disposed of in landfill has the potential to contaminate local groundwater and remain contaminated in-situ for an extended time. Ongoing soil and groundwater monitoring of cutting disposal sites should be undertaken in this case.

7.4 References for Section 7

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[2] UKOOG, 2015, Guidelines for the Establishment of Environmental Baselines for UK Onshore Oil and Gas, Issue 1 January 2015.

[3] England Environment Agency, 2016. Onshore Oil & Gas Sector Guidance.

[4] Directive 2008/98/EC on Waste (Waste Framework Directive).

[5] IOGP, 2008. Guidelines for the management of Naturally Occurring Radioactive Material (NORM) in the oil & gas industry. Report No. 412.

[6] IAEA, 2003. Extent of Environmental Contamination by Naturally Occurring Radioactive Material (NORM) and Technological Options for Mitigation, Technical Reports Series No. 419.

[7] NOGEPA, 2016. Well Engineering and Construction Process. Industry Standard 41.

[8] World Bank / IFC, 2017. Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development, Draft Revised Version: http://www.ifc.org/wps/wcm/connect/topics_ext_content/ifc_external_corporate_site/sustainability-at-ifc/policies-standards/ehs-guidelines/onshoreoilandgas_phase1_secondconsultation

[9] IOGP, 2016. Drilling waste management technology review. Report 557.

[10] European Commission, 2016. Draft BREF for the Management of Waste from the Extractive Industries (MWEI BREF). http://susproc.jrc.ec.europa.eu/activities/waste/documents/MWEI_BREF_Draft.pdf

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8. Onshore Activity 5: Handling of Hydrostatic Testing Water and Well Completion Fluids

8.1 Summary of the Activity and Potential Environmental Impacts

Hydrostatic testing ("hydrotesting") is one of the methods most commonly used by the hydrocarbons industry for testing for system leakages and pressurisation integrity. Hydrotesting typically occurs during pre-commissioning to verify the integrity of pipelines and associated equipment. These are filled with hydrotest water which is then raised to greater than atmospheric pressure, allowing infrastructure to be assessed in terms of its structural integrity. Used hydrotest water typically contains:

- Chemical additives such as corrosion inhibitors and tracer chemicals used during, or present prior to, testing. Oxygen depleting compounds such as sodium sulphite may for example be used to protect against corrosion inside tanks and pipelines;
- Oil, grease and other hydrocarbons from tested infrastructure which may have arisen from previous service, such as benzene, toluene, ethylbenzene, and xylene [1]; and
- Other varied contaminants which may include, for example suspended solids, iron content, and chlorine.

This Section covers planned discharges of hydrotest water, which in turn incorporate both handling of hydrotest water and management of its impacts by addressing potential contamination (e.g. reducing chemical usage, selection of low hazard/risk chemicals). It also covers the treatment and reuse of hydrotest water. Hydrotesting is also dependent on local water resources, and this dependence is addressed within Onshore Activity 10 (Section 13).

If unintentionally released to the environment, hydrotest water has the potential to contaminate soil, surface waters and groundwater. Depletion of dissolved oxygen may result in the case of discharge to water bodies, leading to more wide-ranging impacts on ecosystems. Unintended releases are covered under the handling and storage of chemicals (Onshore Activity 2 - Section 5) and hydrocarbons (Onshore Activity 3 - Section 6).

Well completion involves the placement of tubulars, tools and equipment in a wellbore to convey, pump, or control production or injection of fluids. A variety of fluid types (e.g. water/brine or hydrocarbon based) can be used to clean the wellbore, stimulate the flow of hydrocarbons and/or to maintain downhole pressure during well completion. Many of these are also relevant to well workover operations, which are hence also considered to be covered by this activity. They may be supplemented with chemical additives such as corrosion inhibitor, biocide, oxygen scavenger, acids, glycol, etc. and once used may also contain hydrocarbons and other potentially hazardous substances from the well.

For well completion fluids, this Section covers planned discharges, which in turn incorporates both handling of these fluids and treatment following use, as well as management of the impacts by addressing potential contamination (e.g. reducing chemical usage, selection of low hazard/risk chemicals). Unintended releases during completion operations or during handling of these fluids can lead to contamination of ground/surface water bodies. Unintended releases as well as general handling and storage of chemicals are addressed under Onshore Activity 2 (Section 5), and hydrocarbons are addressed under Onshore Activity 3 (Section 6).

8.2 Best Risk Management Approaches

The best risk management approaches for the handling of hydrotest water and well completion fluids are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels and contains procedures for hydrotest water and well completion fluid handling (Section 3.4.2).
- Ensure that the handling of hydrotest water and well completion fluids is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- For new facilities and modifications to existing facilities, ensure engineering design for handling of hydrotest water and well completion fluids accounts for inherent safety and minimisation of potential for environmental impact in the event of either a planned or unintended release (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Have in place a Spill Contingency Plan for the management of spills of hydrotest water and/or well completion fluids to the environment (Section 3.5.13).
- Consider the Waste Hierarchy Principles [2] in priority order of Prevent, Reduce, Reuse, Recycle, Recover, Dispose to arrive at the appropriate management practices for the handling of hydrostatic test water and well completion fluids (refer to BAT below).

8.3 Best Available Techniques

The following techniques are considered BAT for the handling of hydrostatic testing water and well completion fluids [3,4,5,6]:

- Prevention – reduce the need for chemicals in hydrotest water and well completions in onshore operations, including:
  - Consider integrity testing methods where less or no chemicals or testing water are required.
  - Review hydrotest water and well completion fluid requirements taking into account chemical effectiveness and stability, toxicity, compatibility with other additives used and reactivity towards other materials and compounds used [7].
- Reuse, recycling and recovery - reuse hydrotest water and well completion fluids in operations or recycle and/or recover water for further use, including:
  - Reuse hydrotest water and well completion fluids where practicable by applying appropriate treatment techniques (refer to Onshore Activity 12 (Section 15).
  - Recover and store well completion fluids and transport off site for recycling at an approved facility.
- Disposal – Disposal is the least preferred option when other possibilities have been exhausted and/or deemed impracticable and may (subject to national legislation and/or permit conditions) include:
  - If discharging well completion fluids and/or hydrotest fluids to the environment, undertake on-site or off-site physicochemical treatment prior to discharge, perform quality testing, and only discharge where applicable Environmental Performance Levels (EPLs) are met (refer to Table 8.1).

- For disposal of hydrotest water and/or well completion fluids, inject where practicable into a dedicated disposal well drilled to a suitable receiving subsurface geological formation, where available and permitted by the Regulatory Authority.

Table 8.1 EPLs Associated with the Application of BAT for Pollutants Contained in Hydrostatic Testing Water and Well Completion Fluids at the Point of Discharge [1,3,8]

Parameter	EPLs*
Total HC content (mg/l)	10
pH	6 – 9
Biological oxygen demand (BOD) (mg/l)	25
Chemical oxygen demand (COD) (mg/l)	125
Total Suspended Solids (TSS) (mg/l)	35-45**
Phenols (mg/l)	0.5
Sulphides (mg/l)	1
Chlorides (mg/l)	600 (average); 1200 (max)
Toluene (µg/l)	5
Benzene (µg/l)	5
Ethylbenzene (µg/l)	5
Xylene, Total (µg/l)	10
Arsenic (expressed as As) (mg/l)	0.01–0.1**
Cadmium (expressed as Cd) (mg/l)	0.01–0.1
Chromium (expressed as Cr) (mg/l)	0.01–0.3
Hexavalent Chromium (expressed as Cr(VI)) (mg/l)	0.01–0.1
Copper (expressed as Cu) (mg/l)	0.05–0.5
Lead (expressed as Pb) (mg/l)	0.05–0.3
Nickel (expressed as Ni) (mg/l)	0.05–1
Mercury (expressed as Hg) (µg/l)	1–10
Zinc (expressed as Zn) (mg/l)	0.1–2

* Values are monthly averages.

** In the case of previously used pipelines the upper level of the range applies

8.4 References for Section 8

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9. Onshore Activity 6: Management of Hydrocarbons and Chemicals – Well Stimulation Using Hydraulic Fracturing

9.1 Summary of the Activity and Potential Environmental Impacts

This Section is only applicable in regions where hydraulic fracturing (HF), including high-volume hydraulic fracturing (HVHF) is permitted under national legislation.

During well stimulation using HF, water, together with a proppant such as sand and/or other chemical additives, is injected into the well to fracture the hydrocarbon-bearing formation. The chemical additives generally include corrosion inhibitor to prevent the build-up of scale on the walls of the well, acid to help initiate fractures, biocide to kill bacteria that can produce hydrogen sulphide and lead to corrosion, friction reducers to reduce friction between the well casing and fluid injected into it, and surfactants to facilitate fluid flow [1]. More information on the types of chemicals that may be used is provided under Onshore Activity 2. Information on handling hydrocarbons is provided under Onshore Activity 3.

If not properly controlled, well stimulation through HF may increase the potential for leakage and subsequent contamination by hydrocarbons and fluids containing chemicals into groundwater, surface water and/or soil. This can also include release of contaminants from the reservoir itself (e.g. NORM, heavy metals, naturally-occurring chemical constituents). Furthermore, there is a potential for a pathway to be created, via new fractures, between the different aquifers/groundwater zones that are of different quality and composition.

HF can involve the use of large quantities of liquids and chemicals. Some of these may flow back to the surface, where they should be adequately contained for treatment and disposal. Onshore Activities 2 and 3 address the handling of chemicals and hydrocarbons, respectively, for all onshore exploration and production operations. This Section does not duplicate this information, e.g. on principles related to containment of fluids. It is specifically concerned with risk management approaches and BAT relevant to HF.

9.2 Best Risk Management Approaches

The best risk management approaches for the management of hydrocarbons and chemicals used in HF are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for HF (Section 3.4.2).
- Ensure that the management of HF is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- For new facilities and modifications to existing facilities, ensure engineering design for handling of hydrocarbons and chemicals accounts for inherent safety and minimisation of potential for environmental impact in the event of either a planned or unintended release (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental

incidents (Section 3.5.2). Develop and implement a Hydraulic Fracturing Programme that includes:

- Assess suitability of the well design and integrity for HF (taking into account load conditions and high-pressure testing and using engineering standards such as ANSI/API RP 100-1 [2]).
- Identify fracturing target zones (i.e. geological description of target zone and area).
- Identify groundwater bodies that may be affected in case of unintended release of hydrocarbons or chemicals.
- Identify chemical ingredients and characteristics of each additive and assessing risks in advance, through a pre-assessment process.
- Identify the volume and concentration of the substances in the fracture fluids (identified as part of the fracture treatment design).
- Assess potential environmental and health risks of proposed fracture fluid additives for a specific site/application.
- Establish management measures for the identified risks, for each well fractured, with the goal of reducing the risks.
- Deploy a risk-based monitoring programme.

- Develop Performance Standards, which demonstrate that measures are in place for well integrity and containment [3,4]. Information on performance standards is provided in API RP 100-1 and API RP 100-2 [2,5] as well as by the Centre for Responsible Shale Development [6]. Fracturing operations should be regularly reviewed to ensure alignment with Performance Standards.
- Have in place a Spill Contingency Plan for the management of spills of hydrocarbons and chemicals to the environment (Section 3.5.13).
- Implement specific approaches to manage unintended losses of containment of hydrocarbons and chemicals, including:
  - Perform expert assessment of the suitability of the well design and integrity prior to starting operations.
  - Select well stimulation techniques which may be considered BAT (see Section 9.3 below).
  - Implement asset integrity (maintenance and monitoring) programmes to ensure the integrity of all infrastructure (Section 3.5.11).
  - Verify well integrity on an ongoing basis using, for example, pressure monitoring, leak detection systems for methane and H_2S, and visual monitoring.
  - Provide a buffer zone between the target fracture zone and the groundwater zone, taking into account the exposure risks, geological evaluation of the target formation, overlying and underlying zones [7], geological faults and risks. Target formations are generally separated from groundwater bodies by at least 600 m [8]. In cases where a smaller buffer zone is being considered additional modelling, monitoring and, where appropriate, mitigation measures should be applied (e.g. an impermeable geological layer in that buffer zone as a barrier to fracture propagation).
  - Dedicate and limit access for personnel to critical areas during well intervention.

- Use multiple layers of steel casing and cement to separate the well from the aquifer and to isolate production streams within the centre of the well (e.g. API SPEC 10A [9]). Verify sealing integrity of annulus casing to formation.

9.3 Best Available Techniques

The following techniques are considered BAT for the management of hydrocarbons and chemicals used in HF [2,7,8,10,11,12]:

9.3.1 Design

- Characterise the in-situ stresses within the target formation as part of the planning and design process in advance of drilling and fracturing operations.
- Estimate, in order to avoid possible groundwater contamination from induced fractures [7]:
  - Minimum required vertical separation between the deepest groundwater formation boundary and the shallowest edge of induced fractures.
  - Minimum required distance between the wellbore above the target formation and the nearest edge of an induced fracture.
  - Minimum required distance between the outermost edge of an induced fracture and any nearby wellbores.
  - Minimum required distance between any identified pre-existing faults or fractures to the nearest edge of an induced fracture.
- Ensure barriers are defined and in place to prevent [10]:
  - Uncontrolled flow of hydrocarbons to the environment.
  - Cross flow between adjacent formation layers.
  - Contamination of groundwater during drilling and cementing operations, during the subsequent production phase, until a well is decommissioned.

9.3.2 Operations

- Treat and use/reuse of fluids for HF where practicable, for example reducing the need to transport additional fluids to the site.
- Continually monitor the actual fracture creation, geometry and propagation to understand the geomechanical stress state of the target formation, to improve predictions of induced fracture growth and ensure that no fractures will extend beyond the permitted boundary. Monitoring methods may include:
  - Surveys to identify directions of local stresses and locations of pre-existing faults.
  - Geomechanical modelling calibrated using field observations during the operational process.
  - Micro-seismicity real-time monitoring using appropriate monitoring tools and layouts, allowing direct location of and indirect observation of subsequent induced fracture surfaces.

- Periodically analyse groundwater and surface water for, at a minimum, pollutants that are involved in operations, such as chemicals to be used in the HF process, heavy metals (from flowback water), methane (biogenic/thermogenic), and NORM [13,14].
- Perform pressure monitoring of production casing and annuli during HF operations.

9.4 References for Section 9

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10. Onshore Activity 7: Energy Efficiency

10.1 Summary of the Activity and Potential Environmental Impacts

The hydrocarbons industry is an energy-intensive industry by virtue of the activities it carries out, and hence energy efficiency and energy savings have long been essential to the industry's operations [1]. Energy consuming activities occur throughout field life including during drilling; hydrocarbons production (e.g. for pumping, gas lift, processing, etc.); and for the powering of utilities and auxiliary systems in various phases.

A whole of field life approach to energy management can lead to significant energy use savings and hence reduced air emissions; mitigation of noise issues associated with energy production (e.g. diesel generators); and overall operational cost reductions. This Section focuses on specific approaches and techniques for energy management leading to improved energy efficiency of a facility, over and above those typically considered as part of design, process integration and maintenance [1,2,3]. It should be noted that the applicability of energy efficiency approaches and techniques is highly dependent on both operational phase, the age of the facility and types of processes concerned.

A well-structured energy management system is expected in order to meet minimum requirements of Article 8 of the Energy Efficiency Directive (2012/27/EU) (Annex VI) [4]. Emissions to air from power generation are not in the scope of this activity but are rather covered under the LCP BREF [5] under Directive 2010/75/EU [6] on industrial emissions (IED) as well as under Directive 2015/2193 on the limitation of emissions of certain pollutants into the air from medium combustion plants (Medium Combustion Plant (MCP) Directive) [7].

Other risks directly or indirectly linked to energy efficiency such as the impact of flaring or gas venting, atmospheric emissions and resource minimisation are normally included as part of an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7) and are addressed in Onshore Activity 8 (Section 11).

10.2 Best Risk Management Approaches

The best risk management approaches for improving the energy efficiency of projects/facilities are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels (Section 3.4.2).
- Consider energy efficiency requirements as part of the earliest possible stage of the approval process for all capital investment projects.
- Ensure that energy management is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- Implement an Energy Efficiency Management System, either as a stand-alone system [8] or as part of an integrated management system [9], covering the entire life of field operations and including the following elements [10]:
  - Definition of an Energy Efficiency Policy for the facility, and commitment of senior executives to that Policy.
  - A system framework that includes a strategy with objectives and targets, and a set of operational procedures to support achieving that strategy.
  - A basis for the adopted energy efficiency strategy, including a risk assessment that reviews health, safety, societal, security and environmental risks related to energy consumption to understand trade-offs that may be achieved while managing risk to tolerable levels.

- Mechanisms and tools for forecasting energy consumption over the entire field life, taking into account anticipated variations, e.g. expected changes in production profile for producing installations.
- Benchmarking, including the identification and assessment of energy efficiency indicators (e.g. operational processes, supply chain, etc. [11]) over time, and the systematic and regular comparison with sector, national or regional norms for energy efficiency.
- Performance review and corrective action functions, including:
    - Perform efficiency monitoring including energy metering and monitoring programmes, adequately implemented, to allow an energy consumption baseline to be defined.
    - Review against manufacturers' specifications.
    - Conduct analysis of energy consumption and efficiency and identify practical and cost-effective ways in which energy efficiency can be improved.
    - Ensure ongoing effective maintenance of infrastructure, particularly energy intensive equipment, e.g. compressors and pumps.
    - Conduct periodic energy audits.
- Review of the Energy Efficiency Management System by senior management to ensure its continuing suitability, adequacy and effectiveness.

- For new facilities and modifications to existing facilities, ensure engineering design (Section 3.5.5) accounts for energy efficiency aspects including:
    - For new facilities, apply integrated design practices that consider the facility as a single system and aim to minimise overall energy use across the expected range of operating conditions while maximising production, configuration choices, and treating options.
    - For existing facilities, although fewer opportunities to improve energy efficiency may be available, it is still possible to increase efficiency savings by applying measures targeting energy intensive activities.

10.3 Best Available Techniques

The following techniques are considered BAT for improving energy efficiency[12]:

- Energy efficiency studies – Energy efficiency studies should be performed as part of Concept phase and during options selection processes, including quantification and valorisation of the impact of different options on the various forms of energy (extracted oil and gas, purchased gas and power, energy losses, etc.). Later in the engineering design phase, energy efficiency can be further improved through the optimisation of process parameters, and careful selection of systems and equipment [12].

[12] Note that these should be addressed by the Energy Efficiency Management System outlined in Section 10.2.

- Energy monitoring - Monitoring systems should be implemented widely where practicable in order to collect data, enrich data through appropriate modelling and to provide trends over time to highlight deviations or potential opportunities for energy performance improvement. Monitoring is already widely used by the hydrocarbons industry, and makes use of modern sensors, data collection and information management systems, as well as sophisticated control and analysis software.
- Reservoir management - A strategy for optimum hydrocarbon recovery should be defined during the early design phase, after which the selection of the associated development scheme and needs (artificial lift, pressure support, electric submersible pumps, gas compression, and EOR) may be determined through a strategy to optimise energy use in conjunction with other operational requirements. During operations, reservoir behaviour should be monitored and the data compared with expectations in order to adjust the power scheme accordingly.
- Active control and enhanced monitoring of wells - In addition to reservoir management, the ongoing control and enhanced monitoring of wells contribute to improving production performance, by more rapidly diagnosing and controlling any problematic well behaviour, such as gas lift shortage (single or dual gas lift), surge and flow irregularities as they occur.
- Process systems, oil and gas treatment and export systems - For onshore production, the following should be considered depending on specific project requirements:
  - Compressor type and configuration (including number of trains, number of compression stages, spatial and mechanical configuration, and compressor type) should be optimised for each project. Turbomachinery (i.e. compressors, turbines, pumps) selection should account for variable production profiles where practicable.
  - Oil and gas export system design should be carefully considered in order to meet upstream equipment capacities and process performance requirements, taking into account the requirements over the entire field life. Over-capacity may have a significant impact on the energy efficiency of the facility.
  - Hydrocarbons export needs over the field life should be reviewed to arrive at an appropriate configuration and installation of export pumps, ensuring that optimal efficiencies are achieved for different operating modes.
  - Variable speed drives (VSDs) offer flexibility during the life of field operations when process variations occur (flow rate, pressure, fluid composition, etc.) or when production volumes or conditions are expected to change over time, leading to energy savings and economic benefits.
  - Glycol systems used for gas dehydration should be considered from the perspective of energy requirements, and their dehydration performance optimised appropriately in terms of reboiler temperature, glycol recirculation rate, glycol purity, rich gas pressure and temperature before drying glycol, fuel gas stripping rate, etc.
- Water injection systems - For onshore production, the following should be considered depending on specific project requirements:
  - Injection pump configuration (including number of pumps, spatial configuration) should be optimised for each project, taking into account energy efficiency alongside technology choices, operating conditions and investment and operating costs (energy use).
  - Produced water reinjection. When applicable (suitable reservoir; water quality compatibility, etc.), reinjection of produced water may offer energy savings from reduced requirements for water treatment before injection into the reservoir.

- VSDs – refer to above. For major dynamic machines (e.g. water injection pumps) and when applicable, VSD can lead to energy savings and economic benefits by avoiding discharge and suction recirculation.

- Power generation systems (not resulting in emissions to air on site) - For onshore production, the following should be considered depending on specific project requirements:
  - Waste heat recovery units (WHRUs) may be fitted on turbine stacks to deliver energy and fuel gas savings by recovering heat for use by other systems (e.g. oil/water separation).
  - Power for operations may be obtained from the electricity grid in some cases, negating the requirement to generate it locally. Where practicable, connection to electricity networks may be more efficient depending on the specific nature of facilities and operations.
  - Renewable energy may in some cases be integrated to supplement power requirements depending on availability, economics and the local environment.
- Utilities and auxiliary systems - For onshore production, the following should be considered depending on specific project requirements:
  - Cooling systems have specific energy requirements, and their configuration and performance should be reviewed and optimised according to the facility needs.
  - Heat exchangers are closed loop systems used to recover surplus heat or cooling and reuse it for process purposes (e.g. preheating, conditioning).
  - Energy efficient lighting which reduces power requirements, and assessment of lighting needs and priorities; optimisation of natural light use; selection of appropriate fixtures and energy efficient lamps, e.g. light emitting diode (LED) technology.

10.4 References for Section 10

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11. Onshore Activity 8: Flaring and Venting

11.1 Summary of the Activity and Potential Environmental Impacts

Hydrocarbons operations involve the separation and processing of reservoir fluid combinations of gas, oil and water, along with various other constituents. Systems used for this purpose incorporate flaring and venting capability to release gases to atmosphere. Flaring and venting activities may be employed as part of the [1,2]:

- Exploration phase: during oil and gas well drilling, completion and well testing operations;
- Production phase: during situations including:
  - Routine hydrocarbons production operations;
  - Planned non-routine depressurising of process equipment and pipelines for maintenance; and
  - Unintended non-routine depressurising of process equipment and pipework due to process upsets/trips or emergencies (i.e. as a safety measure).

Flaring specifically describes the situation in which gas is combusted upon its release from the process system via a flare header. Flares are typically positioned at safe distance from the operating plant and personnel to manage any risk of heat radiation and to ensure the safe dispersion of combustion products. Venting refers to the release of unburnt gas from process systems and storage. Onshore, the main sources of vented emissions are from fixed roof storage tanks, wastewater tanks, pumps and pressure controlling equipment (if gas is not flared).

Flaring and venting during the exploration phase is typically of short duration and aimed at gathering data to assist with design of production systems in later field development. Properties of the reservoir may not be well understood at this time, thereby restricting options for use or treatment of gaseous hydrocarbons if these are encountered during drilling, completions or well testing.

Production operations occur over longer timescales and involve putting in place more permanent plant and equipment to recover hydrocarbons, which may include flaring and venting infrastructure as part of the process design. Such infrastructure functions to enable process system depressurisation, in situations such as those outlined above. Design for production systems should hence follow a "depressurisation hierarchy" which ensures that gas arising during hydrocarbons processing is either (in order of preference):

- Routed back into the process (e.g. for use as fuel gas or for export), negating the requirement to emit to atmosphere either carbon dioxide (from flaring) or methane (from venting); or
- Routed to the closed flare system for combustion, resulting in the emission of carbon dioxide to atmosphere, preferable to venting which would instead result in methane emissions; or
- Routed to atmosphere through a vent – the least preferred option from an environmental perspective, and which results in the emission of unburnt methane to atmosphere.

The decision around which of these three routes gas should take is taken based on technical, safety, regulatory, and economic constraints [3]. Given the long-term nature of production operations, changes to working practices and plant modifications can have long term, sustainable and material impacts on flare and vent emissions, and should hence be carefully considered at an early stage. New production facilities should be designed in accordance with the principle of "no requirement for routine operational flaring or venting".

Examples of activities which can result in venting (and potentially flaring) include all gas releases from pressurised equipment (e.g. well workovers, completions, pipeline pigging, etc.) and also hydrocarbon processing (e.g. gas dehydration process, sour gas treatment processes, etc.). Emissions from venting comprise mainly emissions of hydrocarbons, primarily methane and NMVOCs. Emissions from flaring are primarily carbon dioxide (CO_2), as well as carbon monoxide (CO), methane, VOCs, oxides of nitrogen and sulphur (NO_x, SO_x) and other pollutants [1].

Flaring and venting are widely recognised as a significant source of greenhouse gas (GHG) emissions and air pollution, for which risks must be managed accordingly. As outlined above, flaring is a preferred alternative to venting as it is both safer (it removes the potential for unplanned ignition of the gas) and it reduces emissions of methane, which has a higher global warming potential than carbon dioxide [4]. Flaring also has the potential for impacts from light and/or noise, which may need to be considered depending on environmental sensitivities at specific locations. Emissions management as a risk management approach is discussed further in Section 3.5.14.

A detailed discussion on the use of flaring and venting as a safety measure is not included in the scope of this Section. However, this function is recognised and many of the risk management approaches and BAT that cover flaring and venting also have safety applicability. Note that under many jurisdictions, flaring and venting are permitted activities overseen by the Regulatory Authority.

Fugitive emissions are not included in this activity and are addressed as part of Onshore Activity 9 (Section 12).

11.2 Best Risk Management Approaches

The best risk management approaches for flaring and venting are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for management of flaring and venting (Section 3.4.2).
- Implement an Emissions Management Plan that covers the management of facility GHGs including methane and carbon dioxide from flaring, venting and fugitive emissions. This Plan should provide the technical, commercial and environmental justification for the management of emissions, and should take into account reservoir characteristics including composition of fluids and likely variation over time (e.g. in water, H_2S and gas-to-oil ratios). Level of detail should be consistent with facility complexity (Section 3.5.14).
- Address management of flaring and venting as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7). These may reference the Emissions Management Plan outlined above.
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Consider operating efficiency across all phases of the development from design, through exploration, production and decommissioning. Maximising operating efficiency minimises the potential for unplanned flaring events.
- When designing new facilities or making modifications to existing facilities, apply an option selection process to determine the potential for reducing flaring and venting and for recovery of gas. This may include (Section 3.5.5) [5]:

- Ensure, for new facilities, the capture of gases for subsequent use, and the minimisation of flaring and venting. In particular, measures should be put in place to ensure that air emissions at the production stage are mitigated by capturing gas and its subsequent use.
- Design new production facilities in accordance with the principle of no requirement for routine operational flaring or venting.
- Design the flare system to accommodate the range of gas flow rates and composition as predicted for the exploration/commissioning phase and, informed by actual data, for the production and ultimately decommissioning phases.
- Design to recover gas by recycling it back into the process system. For new facilities, recovery of gases is well-proven for larger emission sources/processes [6]. For existing facilities, additional recovery of waste gas may require technical modifications to processing plants e.g. installation of low-pressure compressors. It is therefore important to take account of constraints regarding the specific characteristics of the facility (type, age, space constraints) and reservoir properties. Applicability issues are addressed at the end of this Section.
- For new facilities, design flare systems handling high pressure sources to recover gas during normal operation. Recovery of gas from flare systems handling low pressure systems during normal operation should be considered.
- Minimise venting from purges, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units and inert purge gas.
- Minimise liquid carry-over and entrainment in the gas flare stream with a suitable liquid separation system.
- Design flare systems with steam or air-assist to ensure an adequate air supply and mixing (steam can aggravate the flare noise problem by producing high-frequency jet noise).
- Ensure that any non-hydrocarbon gases such as H_2S or ammonia which may be directed to flare are mixed with a sufficient quantity of hydrocarbon gas to maintain complete combustion of both types of gases at the flare tip.
- Use enclosed ground flares where there is the potential for significant impacts on local communities from light and/or noise associated with flaring operations, as determined by Site Selection/EIA studies (Section 3.5.4).
- Design vents such that these are routed to flare where possible.
- Provide the possibility for flare gas metering/estimation per requirements of the EU Emissions Trading System (ETS) [7].

- Examples of specific approaches that may be implemented include:
  - Exploration (e.g. well testing):
    - Opportunities to reduce flaring should be considered during the earliest possible planning stage. For well testing, this implies the time at which the duration and intensity of tests are defined.
    - Reviews should be conducted involving representatives from multiple functions to optimise planning for well testing. Opportunities to minimise flaring once a well testing programme has started are likely to be much more limited.
    - Oil flaring should be minimised by use of temporary storage wherever possible and practicable. It should be recognised that separating oil, gas and water can prove

difficult on some exploration well tests and such difficulties might not be known until the well is tested.

- Flaring from well testing should be eliminated where feasible. This will not always be possible and therefore the duration and intensity of the well test should be justified based on technical, financial and environmental basis.
- For new developments operators should be encouraged to consider in project design concepts whether conventional well testing may be avoided entirely.

- Production operations:
  - Minimise flaring and venting from the point of view of both environmental reasons and for the purposes of optimising resource efficiency (avoiding the waste of finite resource and the associated revenues).
  - Allowable flaring and venting levels should take into consideration factors including the availability of export infrastructure, and design and technology options which may be appropriate based on the balance of costs and benefits. They should also take into consideration that options to manage flaring and venting may be significantly affected by the potential for use of gas streams[13].
  - Flaring targets (e.g. for commissioning and operation/production) should try to achieve continuous improvements in performance and should specify conditions/arrangements for any deviation (e.g. a possible increase in the target might be justified, for example, to implement a maintenance intervention which sustainably reduces flaring).

11.3 Best Available Techniques

The following techniques are considered BAT for flaring and venting [5,6,8,9]:

11.3.1 Flaring

- Implement source gas reduction measures to the maximum extent possible, including ensuring that hydrocarbon processing plant and/or equipment is designed for optimal efficiency and reliability.
- Minimise venting of hydrocarbons from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units and inert purge gas.
- Provide auxiliary power to prevent trips to flare.
- Consider either "continuously lit pilots" or "ignition-on-demand" as the primary ignition system. These can eliminate or at least minimise delay in achieving an ignited flare; and reliability of the ignition system [10].

[13] Availability of midstream and downstream infrastructure including pipeline capacity, oil and gas terminal capacity, storage and end consumers including refineries and other users of the gas streams. The loss or restriction of this infrastructure can result in no viable alternative to flaring or venting.

- For new facilities or when making modifications to existing facilities, specify efficient flare tips, taking into account: combustion efficiency, optimised size and number of burning nozzles, and variability of flaring rates and gas composition [10]; and optimise the flare design according to process conditions over the expected field life.
- For flare systems which have either steam or air injection systems, maximise flare combustion efficiency by controlling and optimising temperature, and flow rates to ensure the correct ratio of flare gas/air/steam is achieved.
- Specify a reliable flare pilot ignition system including an adequate supply of pilot gas with a sufficiently high calorific value, a pilot flame detection system and wind guards.
- Specify reduced emissions completions (REC) also known as "green completions" in design, for production operations.
- Use flares with windshields on pilot burners as well as on the main burner, to improve combustion efficiency by deferring sidewind impacts and reducing disturbance due to light from the flare.
- Perform flare monitoring to detect and address conditions that indicate inefficient combustion such as flame lift off, flame lick or visible black smoke.
- Regularly analyse gas sent to flaring and associated parameters of combustion (e.g. flow gas mixture and heat content, ratio of assistance, velocity, purge gas flow rate, pollutant emissions).
- Perform flare inspection, maintenance and replacement programmes to ensure continued flare efficiency.
- In addition, consider implementing flare noise avoidance measures where possible, including:
  - Use of multiport steam injectors to reduce high frequency steam jet noise.
  - Installing injectors in a way that allows jet streams to interact and reduce mixing noise.
  - Increasing efficiency of the suppressant with better and more responsive forms of control.
  - Restricting steam pressure.
  - Using a silencer around the steam injector as an acoustic shield for the injectors.
  - Using air-blown flares or enclosed ground flares to reduce noise.

11.3.2 Venting

- Design to route low pressure atmospheric vents (for example from glycol dehydrators) to flare gas recovery or, where this is not feasible, to flare.
- Use an inert gas (e.g. nitrogen) as a stripping and flotation gas in dissolved gas flotation systems used for treating waste water; as a secondary seal gas in mechanical compressor seals; and as a purge or blanket gas in storage tanks e.g. crude oil storage tanks or medium expansion tanks.

Additional guidance in this area includes [11-19].

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12. Onshore Activity 9: Management of Fugitive Emissions

12.1 Summary of the Activity and Potential Environmental Impacts

Fugitive emissions are emissions that arise from plant and equipment used during hydrocarbon exploration and production operations [1]. They include emissions from leaking equipment; pipes and tubing; valves; flanges and other connections; packings; open-ended lines; pump seals; compressor seals; pressure relief valves; and from hydrocarbon loading and unloading operations [2]. Fugitive emissions may be considered as a subset of diffuse emissions, which also include point-source emissions and venting. Diffuse emissions, for example of VOCs from outdoor storage/retention ponds, are considered in other sources, e.g. the Refineries BREF [3].

Fugitive emissions typically include releases of hydrocarbon gas such as methane and non-methane volatile organic compounds (NMVOC). They do not include hydrocarbons released through combustion processes or process vents. Fugitive emissions are widely recognised as a source of GHGs and air pollution, for which risks must be managed accordingly. Methane is a primary constituent of produced gas and a GHG with global warming potential over 20 times that of carbon dioxide [4]. Emissions management as a risk management approach is discussed further in Section 3.5.14. While NMVOC emissions are less critical from a GHG perspective, their reduction is important for improving local air quality.

Causes of fugitive emissions include improperly fitted connection points or deteriorating seals; and the changes in pressure, temperature, or mechanical stresses that lead to this component and/or equipment degradation. Methods for controlling and reducing fugitive emissions should be considered and implemented in the design and operation of facilities. Fugitive emissions should also receive significant focus from a maintenance and integrity perspective as they are a leading process safety indicator [2]. Proposed measures to avoid and reduce fugitive emissions should be considered in the context of the type of operation, facility and location concerned.

Flaring and venting for onshore facilities are addressed in Onshore Activity 8 (Section 11).

12.2 Best Risk Management Approaches

The overarching best risk management approach for fugitive emissions is to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for managing fugitive emissions (Section 3.4.2).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Implement an Emissions Management Plan that covers the management of facility GHGs including methane and carbon dioxide from flaring, venting and fugitive emissions (Section 3.5.14). This Plan should provide the technical, commercial and environmental justification for the management of emissions, and should take into account reservoir characteristics including composition of fluids and likely variation over time. Level of detail should be consistent with facility complexity. The Emissions Management Plan may include Hydrocarbon Release Management Procedure(s) (or equivalent) [5-14].

- Hold an inventory of existing and potential fugitive emission sources, and estimate fugitive emissions from these, based on consistent theoretical methodologies (i.e. repeatable calculation methodologies, estimation techniques and emission factors). The calculation of fugitive emissions where direct monitoring results are not available involves the use of an activity factor (e.g. fuel consumption or flow to flare/vent), and an emission factor for each source and emission gas. Guidance in this area includes [15-18].
- Fugitive emissions should be addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7), which may be cross referenced to the Emissions Management Plan outlined above.
- When designing new facilities or making modifications to existing facilities, ensure engineering design accounts for inherent safety and the minimisation of potential for environmental impact of fugitive emissions (Section 3.5.5) [19] (refer to BAT below).
- Implement leak detection and repair (LDAR) for monitoring fugitive emissions during operations, with leak screening techniques and/or direct measurement, which may include periodic facility inspections using detection equipment, flange management, etc. [12,20-25] (see BAT below). Requires keeping an up to date equipment register such that leaks can be tagged and repaired.

12.3 Best Available Techniques

The following techniques are considered BAT for the management of fugitive emissions:

12.3.1 Design

- Limit the number of potential emission sources.
- Maximise inherent process containment features.
- Minimise use of flanges and other potential leak paths.
- Select high integrity equipment including valves, flanges, packings, seals and equivalent fugitive sources, to minimise leakage to the external environment.
- Consider welded piping for high and low-pressure lines containing hydrocarbon inventory.
- Specify valves with double packing seals.
- Preference for zero bleed pneumatic controllers over hydrocarbon gas-driven controllers.
- Use magnetically driven pumps/compressors/agitators where practicable.
- Use pumps/compressors/agitators fitted with mechanical seals instead of packing.
- Specify high-integrity gaskets (such as spiral wound, ring joints) for critical applications.
- Where practical, facilitate monitoring and maintenance activities by providing ease of access to potentially leaking components.
- Select appropriate centrifugal compressor seals - Seals on the shafts of centrifugal compressors designed to prevent gas from escaping the compressor casing. These may use oil (wet seals) or mechanical seals (dry seals). Wet seals result in gas being entrained in the oil and then released when the oil leaves the compressor, resulting in a constant fugitive emission during compressor operation. Although dry seals do not use oil, some fugitive emission is still associated with gas

escaping around the rotating compressor shaft, which is considered unavoidable and is also present in wet seals.

- Ensure appropriate fixed fire and gas (F&G) detection systems are specified, to detect larger volume emissions.

12.3.2 Operations

- Sniffing method – Undertake leak detection using hand-held personal analysers, to identify leaking components by measuring the concentration of hydrocarbon vapours in the immediate vicinity of the leak with a flame ionisation detector (FID), a semi-conductive detector or a photo-ionisation detector (PID). The selection of the most suitable type of detector depends on the nature of the substance to be detected (e.g. [22,23]).
- Optical gas imaging (OGI) method –Undertake leak detection using hand-held cameras that can visualise the release of gas using spectroscopic techniques (e.g. NTA 8399:2013). Ongoing developments in the field may eventually lead to OGI being able to provide quantified emissions measurements. OGI cameras are used as part of routine processes and provide a useful means of identifying the presence of small-scale leaks and seeps, especially in otherwise inaccessible facility areas. User training and competency maintenance are essential.
- Assurance and verification – Ensure that the breaking and re-making of flanged joints, including leak testing, is adequately covered by maintenance procedures as part of the facility planned maintenance system (Section 3.5.113).
- Real time methane detection – A range of quantification techniques are currently emerging which may in the future offer the opportunity to quantify emissions from a facility at a broad scale. These include solar occulation flux (SOF) or differential absorption LiDAR (DIAL) campaigns. They are included to provide context for future developments only and should not be considered representative of current BAT.

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13. Onshore Activity 10: Water Resources Management

13.1 Summary of the Activity and the Potential Environmental Impacts

Water management is an essential requirement for upstream onshore hydrocarbons operations, which may need to access significant quantities of water and to manage large volumes of water produced, waste water and rainfall runoff. Operations may also be dependent on water resources at local and regional levels.

The type of hydrocarbon resource being developed, and the maturity of the site will determine how water is used and managed, the requirements for water quality, and the scope for water use efficiency. Other factors include the cost of potable water, the availability and means of collection of rainwater, and the amount of desalination necessary in cases where saline water is the only available source. Typical categories of water use in onshore hydrocarbons operations are summarised in Table 13.1.

Table 13.1 Water use and Categories of Used Water in Onshore Hydrocarbons Operations (Adapted from [1])

Water uses	
Personnel supply	Drinking, personal hygiene, food preparation, laundry, toilet flushing and cleaning
Construction and commissioning	Concrete batching, dust control, road surfacing, hydro-testing pipelines, commissioning
Exploration, drilling and completions	Drilling fluids, well linings (cement/grout), well stimulation fluids, well flushing, well workovers, re-completions/re-fracturing fluids*
Production	Development and extraction of resource from the reservoir
Process and operations	Boiler feed, pump seals, firewater, wash down, cooling water, resource refining and desalters
Categories of used water	
Wastewater	Sewage effluent, 'grey water' (hand basins, showers, baths, laundries and kitchens), industrial effluent and drainage, rainfall run-off
Produced water	Water from the hydrocarbon reservoir
Flowback water*	Water from the well during hydraulic fracturing operations which includes fracturing fluids (including chemicals) and water from the reservoir *
Utility water	Water from blowdown, i.e. condensed water from coolers, dehydration, etc.

* Water resources management related to hydraulic fracturing is addressed in Onshore Activity 9.

Appropriate water management is required to reduce dependency (and potential strain) on both local and regional water resources that may be shared with other users. It is also critical in order to avoid impacts on the environment including to ecosystems and water quality.

Management of water resources should aim to protect the environment by ensuring that water issues are addressed using a systematic approach that:

- Minimises demand on water supply and potential disruption to other local/regional water users;
- Maximises the potential for use, reuse, recycling or other recovery of water produced during operations; and
- Minimises discharge to the environment.

At the EU level, the Water Framework Directive (2000/60/EC) [2] is the most comprehensive instrument of water policy and its main objective is to protect and enhance EU water resources to achieve good status.

This Section addresses the management of water resources used during construction, well drilling, completions and production operations. The focus is on the selection of water resources, water use and efficiency. The management of hydrotest water is addressed in Onshore Activity 5 (Section 8) and produced water is addressed in Onshore Activity 11 (Section 12). Water resources management specifically related to hydraulic fracturing is addressed in Onshore Activity 9 (Section 14) as this is only applicable in regions where hydraulic fracturing and other similar techniques are allowed under local legislation.

13.2 Best Risk Management Approaches

The best risk management approaches for water resources management are to:

- Implement a risk-based Water Management Programme with a view to protecting the environment and to ensuring that water issues are addressed using a systematic approach that minimises water demand and maximises the potential of reuse and recycling [3]. The Water Management Programme should include:
  - Identification and planning of principal water flows from, to and within the site, distinguishing between freshwater and non-freshwater sources. This may be supported by the drafting of a "Water Sourcing Plan", an example of which is provided in API 100-2 Guidance [4].
  - Monitoring of water flows allowing for more effective water management, including metering and engineering estimates. Monitoring should provide an understanding of the quantity of water that is used, reused, recycled and discharged; and the potential for efficiency gains.
  - Implementing water use efficiency and reduction measures where practicable, taking into account the Waste Hierarchy Principles [5] in priority order of Prevention, Reuse, Recycle, Recover, and Dispose (for further explanation, refer to BAT below).
  - Definition and regular review of performance targets or other relevant targets (e.g. reducing freshwater use through reuse or recycling) for water use and discharge, adjusted to account for changes in major influencing factors (e.g. production stage).
  - Regular comparison of performance targets with actual water use and discharge, particularly in areas of water stress, and supported by risk assessment tools to identify where action should be taken to reduce water use. Examples of such tools include (but are not limited to):

- World Resources Institute (WRI) Aqueduct™ Water Risk Atlas [6].
- IPIECA Global Water Tool for Oil and Gas[14] [3,7].
- Global Environmental Management Initiative (GEMI) Local Water Tool™ for Oil and Gas [8].

- Have in place a Spill Contingency Plan for the management of spills of contaminated water to the environment (Section 3.5.13).
- Ensure that water management during operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7). The Water Management Programme described above should inform the EIA, which requires that consideration be given to the management of natural resources including water, and its environmental implications [9].

13.3 Best Available Techniques

The following techniques are considered BAT for water resources management:

- Prevention – reduce the use of water in onshore hydrocarbons operations (refer to Table 13.1 for generalised categories), prevent water losses, and improve water efficiency including:
  - Identify possible reduction of the use of water in processes and facilities. The reference Efficiency in water use – Guidance document for the upstream onshore oil and gas industry (IPIECA, 2014) [10] presents a systematic process and practical examples to identify and assess potential measures to improve water efficiency for both new and existing operations.
  - Select water resources to favour non-freshwater sources, for example the use of brackish/saline groundwater as an alternative to freshwater use. The reference Identifying and assessing water sources (IPIECA, 2014) [1] presents a systematic process and practical examples to select water sources that best meet project needs within the broader context of local or regional water management.
- Reuse – reuse (reuse with minimal or no treatment) water in onshore hydrocarbons operations (refer to Table 13.1 for generalised categories) including:
  - Reuse water for site preparation and construction, drilling (mud preparation), dust suppression, site wash down, irrigation/reclamation water, boiler make-up water, and where practicable and where personnel safety is not compromised: fire-fighting.
  - Use produced water for reservoir pressure maintenance (i.e. reinjection into the producing reservoir) (see onshore Activity 11, Section 12).
  - Reuse drilling and completion fluids in subsequent wells/drilling operations.
  - Reuse of hydrotest water in subsequent commissioning activities.
- Recycling and recovery – Recycle and/or recover water for further use, including:
  - Use treated grey water and treated rainwater (run-off) instead of fresh water.

[14] This document presents a framework for water management in onshore oil and gas activities and involves a cyclical process of planning, implementation, evaluation and review.

- Consider the recycling, after treatment, of used water by third parties as appropriate (e.g. other nearby hydrocarbon facilities, industry, agriculture).

- Disposal – Disposal is the least preferred option when other possibilities have been exhausted and/or deemed impracticable and may (subject to national legislation and/or permit conditions) include:
  - Inject after treatment into suitable confined underlying formations with similar or lower water quality via deep wells, e.g. by low-level treatment, filtration, demineralisation, desalinisation, or evaporation of water.
  - Discharge after treatment, e.g. by low-level treatment, filtration, demineralisation, desalination, evaporation of water. Treatment (also for injection, above) may include:
    - Low-level treatment such as basic filtration using fabric mesh, physical separation, maceration and settling processes (e.g. basic settling of suspended solids).
    - Filtration including membrane filtration, primary, micro, ultra and nano-filtration depending on substances being removed. For example, nano-filtration is used for removing dissolved divalent and polyvalent ions.
    - Further details of water treatment techniques, for example available in [10].

13.4 References for Section 13

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14. Onshore Activity 11: Water Resources Management for Hydraulic Fracturing

14.1 Summary of the Activity and the Potential Environmental Impacts

This Section is only applicable in EU member states where hydraulic fracturing (HF) is permitted under national legislation.

During well stimulation using HF, water, together with a proppant such as sand and/or other chemical additives, is injected into the well to fracture the hydrocarbon-bearing formation. The chemical additives may include corrosion inhibitor to prevent the build-up of scale on the walls of the well, acid to help initiate fractures, biocide to kill bacteria that can produce hydrogen sulphide and lead to corrosion, friction reducers to reduce friction between the well casing and fluid injected into it, and surfactants to facilitate fluid flow [1].

As water is generally the base fluid used for HF activities, HF often makes use of significant quantities of water, requiring appropriate management. Depending on the location, HF can place additional stress on local and regional water resource availability. If not properly controlled, well stimulation through HF a may increase the potential for leakage and subsequent contamination by hydrocarbons and fluids containing chemicals into groundwater, surface water and/or soil. This can also include release of contaminants from the reservoir itself (e.g. NORM, heavy metals, naturally-occurring chemical constituents). Furthermore, there is a potential for a pathway to be created, via new fractures, between the different aquifers/groundwater zones that are of different quality and composition.

This Section is concerned with the management of water resources for hydrocarbons activities involving HF, with techniques related to water resource inputs (dependencies) distinguished from techniques for the management of discharges (impacts). Onshore Activity 6 (Section 9) addresses potential impacts from hydrocarbons and chemicals during well stimulation using hydraulic fracturing. This Section does not duplicate this information. The management of hydrotest water is addressed in Onshore Activity 5 (Section 8) and produced water is addressed in Onshore Activity 11 (Section 12). General water resources management in hydrocarbons activities is addressed in Onshore Activity 8.

While similarities exist in water management challenges posed by conventional hydrocarbons extraction, there are also important considerations related to HF including that it:

- Uses a larger volume of water and chemical additives, which in turn usually generates larger volumes of wastewater (e.g. flowback water) and produced water which could require treatment and disposal;
- Requires the transportation of water to the well pad and the transport of flowback water and fracturing fluids, from the well pad for use, reuse, recycling and/or disposal; and
- Likely attracts greater public concern and scrutiny than conventional oil and gas.

Water resource management related to HF operations includes activities such as water sourcing, chemical mixing, water injection into the well, handling of flowback/produced water, water reuse, recycling and disposal. Water uses specifically related to HF on which onshore hydrocarbons operations are dependent are summarised in Table 14.1.

Table 14.1 Water Dependencies Related to HF in Onshore Hydrocarbons Operations (Adapted from IPIECA, 2014 [2])

Water dependencies	Description/examples
HF operations	Fracturing fluids, well stimulation fluids and well flushing

Water types arising from hydrocarbons operations that has the potential to negatively impact the environment are summarised in Table 14.2.

Table 14.2 Water with Potential for Impact, Specific for HF Operations (Adapted from IPIECA, 2014 [2])

Water with potential for impact	Description/examples
Produced water	Water produced from the hydrocarbon reservoir (refer to Onshore Activity 11)
Flowback water	Water from the well during hydraulic fracturing operations which includes fracturing fluids (including chemicals) and water from the reservoir
Fracturing fluids	Fluids, including additives, injected into the well as part of HF operations

Management of water resources should aim to protect the environment and to ensure that water issues are addressed using a systematic approach that:

- Minimises demand of water supply and potential disruption to other local/regional water users;
- Maximises the potential for use, reuse, recycling or other recovery of water produced during operations; and
- Minimises discharge to the environment.

At the EU level, the Water Framework Directive (2000/60/EC) [3] is the most comprehensive instrument of water policy and its main objective is to protect and enhance EU water resources to achieve good status.

14.2 Best Risk Management Approaches

The best risk management approaches for water resource management for HF are to:

- Implement a Water Management Programme that includes a specific section on HF risks. More information on the Water Management Programme and its recommended content is included in Onshore Activity 8 (Section 12).
- Perform, as part of the Water Management Programme, a HF Water Risk Assessment addressing the following:
  - Sourcing of water for making the HF fluid, considering local water availability, project water demands (quality and quantity) [4].
  - Suitability of the infrastructure and logistics (e.g. water storage, water transport, treatment) for the HF operation [5].

- Expected quantity (volumes) and quality of produced water from the hydrocarbons reservoir.
- Potential for management of spent HF water in terms of the Waste Hierarchy [6] principles of Prevention, Reuse, Recycling, Recovery and Disposal (discharge, evaporation, disposal well injection) options, including required treatment involved in these options (for further explanation, refer to BAT below) [7].
- Planning to ensure well integrity in order to protect water resources during HF activities [8].

- Ensure that energy management is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Section 3). Given the potentially sensitive nature of HF operations among external stakeholders, the EIA should include a social component, specifically a "Community Engagement Plan" to understand and manage public perception of risks and impacts, including to the natural environment [9-12].
- Have in place a Spill Contingency Plan for the management of spills of any of the types of water and/or chemicals used in HF operations (refer to Table 14.1 and Table 14.2) to the environment (Section 3.5.13).

14.3 Best Available Techniques

The following techniques are considered BAT for water resources management for HF:

- Prevention – reduce the use of water in HF operations (refer to Table 14.1) including:
  - Undertake monitoring of water volumes and origin, in particular during dry periods.
  - Control water losses to the formation, for example during cementing, by using fluid loss additives.
  - Produce a Water Sourcing Plan which sets out principles for water use including the selection of water resources to favour non-freshwater sources, for example the use of brackish/saline groundwater as an alternative to freshwater use. Guidance may be found in IPIECA, 2014 [2].
  - Select lower quality water for fracturing (e.g. non-potable water, rainwater harvesting, saline and brackish aquifers, sea water, treated industrial wastewaters).
  - Replace water with other substances (e.g. carbon dioxide) where technically feasible, providing this does not compromise the safety of the operation. Note that this is considered an emerging technique and is included to provide context for potential future innovations. It should not be considered representative of current best practice.
- Reuse, recycling and recovery - reuse spent water in HF operations or elsewhere (refer to Table 14.2); or recycle and/or recover water for further use, including:
  - Collect and reuse fluids (e.g. flowback and produced water) for HF operations where practicable.
  - Collect and reuse fluids (e.g. flowback water) for well drilling operations where practicable.
  - Demineralise and/or desalinate produced water in order to use for HF; however with more recent HF fluid formulations, desalination of the produced water may not always be necessary for its reuse.

- Disposal – This is the least preferred option when other possibilities have been exhausted and/or deemed impracticable and may (subject to national legislation and/or permit conditions) include:
  - Discharging after treatment, e.g. by low-level treatment, filtration, demineralisation, desalination, evaporation of water [13]. Treatment (also for injection, above) may include:
    - Low-level treatment such as basic filtration using fabric mesh, physical separation, maceration and settling processes (e.g. basic settling of suspended solids).
    - Filtration including membrane filtration, primary, micro, ultra and nanofiltration depending on substances being removed. For example, nanofiltration is used for removing dissolved divalent and polyvalent ions.
    - Further details of water treatment techniques, for example available in [14].

14.4 References for Section 14

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15. Onshore Activity 12: Produced Water Handling and Management

15.1 Summary of the Activity and Potential Environmental Impacts

Produced water arises from hydrocarbon production and includes formation water from the reservoir brought to the surface along with hydrocarbons, as well as condensation water and re-produced injection water. Constituents of produced water therefore originate from two main sources: the reservoir itself, and from chemicals used at the facility during production. Together these may include [1]:

- Liquid and/or gaseous hydrocarbons and other organic substances – Occurring in the reservoir and present in crude oil and natural gas condensate (e.g. benzene, toluene, ethylbenzene and xylene - BTEX), phenanthrene, naphthalene, ethyl benzene and phenol), or used in exploration operations (e.g. drilling, completions) and production processes. May occur as dispersed/dissolved hydrocarbons or free oil floating on the surface of water;
- Production chemicals, including for example corrosion inhibitors, scale inhibitors, demulsifiers, biocides and dehydration chemicals. Further details of chemicals used offshore are provided in Section 5.1;
- Heavy metals, NORM and other inorganics – Natural radioactivity and heavy metals, low levels of which may be selectively concentrated in the produced water stream, e.g. uranium, thorium, radium, radon-gas, lead, arsenic, cadmium, chromium, copper, cyanide, mercury, nickel, silver, zinc, vanadium, antimony, and barium [2]. Sulphides may also be present;
- Salts – measured as salinity, total dissolved solids, or electrical conductivity;
- Produced water may also have a high temperature by nature of its long residence time in subsurface geological formations, depending on reservoir characteristics including depth.

Produced water is typically the largest effluent by-product by volume from hydrocarbons operations and can have impacts if discharged to the environment. Onshore, these include contaminated soils, surface water or, over longer periods, groundwater. The type and location of reservoirs has a significant influence on the volume and composition of produced water, as well as the chemicals used and hence present in produced water.

Produced water typically increases in volume over time as the reservoir is depleted during production. In terms of its management, produced water may be either reinjected into a formation for production purposes, injected into a dedicated disposal well, or treated and discharged to the environment. Choosing among these alternatives should take into account energy use, required chemicals, produced water quantity and cost. Although produced water injection is preferred to water treatment and discharge, this solution necessitates suitable injection wells and formations being available, which is frequently not the case. Such information should, however, be considered by the Regulatory authority prior to the project approvals stage.

Produced water treatment and discharge is considered the least preferred option from an environmental perspective, to be applied in the absence of other credible alternatives, and where the discharge meets environmental regulatory and quality standards. In order to meet such standards, treatment using a variety of technologies is required to reduce the dispersed oil content. The effectiveness of such technologies is dependent on its properties, such as whether dispersed hydrocarbon is present, and hydrocarbon droplet size [3]. Onshore, possible uses of produced water include use by other industries, which may be appropriate to consider if the composition of the produced water is compatible with these options.

This Section covers handling and planned discharges of produced water. Unintended releases of produced water may occur due to an accidental event caused by, for example, failure of equipment or human error. This may include loss of containment from storage tanks, or accidental release of untreated produced water from pipework/pipelines. Loss of containment of produced water represents a chemical and hydrocarbon release, and is hence considered as part of Onshore Activities 2 (Section 5) and 3 (Section 6) of this Guidance Document respectively.

15.2 Best Risk Management Approaches

The best risk management approaches for the handling and management of produced water are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for produced water management (Section 3.4.2).
- Ensure that the management of produced water during onshore operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Section 3.5.4/3.5.7).
- For new facilities and modifications to existing facilities, ensure that engineering design includes an option selection process to determine the potential for produced water reduction, reuse, reinjection, and/or treatment and discharge (Section 3.5.5 and Section 15.3).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Implement a Water Management Programme, which should integrate with broader site water management, as detailed in Onshore Activity 8 (Section 12) and include a number of elements specific to produced water, as follows [2]:
  - Identification, analysis, regular measurement, and recording of produced water flows.
  - Planning discharge away from environmentally sensitive areas, with specific attention to high water tables, vulnerable aquifers, and wetlands and community receptors (e.g. water wells, water intakes, and high-value agricultural land).
  - Definition and regular review of performance targets, which are adjusted to account for changes in major factors affecting produced water (e.g. production rate).
  - Pre-selection of production chemicals taking into account their volume, toxicity, persistence, bioavailability, biodegradation and bioaccumulation potential.
  - Regular comparison of produced water flows and hydrocarbon concentrations with performance targets to identify where action should be taken to reduce produced water and associated environmental impacts.
  - Strategy to ensure that possible reinjection of produced water or disposal by injection is maximised.
  - Avoiding excessive produced water through production optimisation in accordance with performance targets and BAT.
  - Discharge planning that considers points of discharge, rate of discharge, chemical use and dispersion, and environmental risk.
- Monitor to verify the effectiveness of risk management measures adopted for produced water management, including via system monitoring, effluent monitoring, and field monitoring. This

should be performed on an ongoing periodic basis, or when significant facility changes occur. It should include definition and continual review of performance targets adjusted to account for changes in major factors affecting produced water (e.g. production rate). Refer also to Onshore Activity 12 (Section 16).

- Implement approaches to manage unintended losses of containment of produced water, which should be considered as releases of hydrocarbons and chemicals as detailed in Onshore Activities 2 (Section 5) and 3 (Section 6), including the consideration of appropriate storage of produced water such as in covered storage tanks.
- Manage produced water during operations using one of the following approaches, which may be considered in a hierarchy (refer to BAT below), as follows:
  1. Minimise and use/reuse produced water where practicable during operations (e.g. re-injection during production for pressure support).
  2. Reinject produced water during production as appropriate or inject into a dedicated disposal well.
  3. Treat produced water to reduce constituents with potential environmental impacts below acceptable EPLs, prior to discharge.

15.3 Best Available Techniques

The following techniques are considered BAT for produced water handling and management:

- Minimise and use/reuse produced water where practicable during operations:
  - Optimise well management during well completion activities and subsequent hydrocarbon production operations to minimise produced water.
  - Perform recompletion of high water-producing wells to minimise produced water.
  - Use downhole fluid separation techniques, where possible, and water shutoff techniques, when technically and economically feasible.
  - Use/reuse produced water, whenever possible, typically with some level of (on-site and/or off-site) treatment, for example for reservoir pressure maintenance (EOR), or for use/reuse by third parties. Requires ensuring that any potentially harmful constituents (e.g. NORM) are not discharged to the receiving environment [4,5,6].
- Reinject produced water during production as appropriate or inject into a dedicated disposal well [7,8]:
  - Achieve EPLs set for the injection of produced water that depend on the receiving environment (i.e. geological formations/reservoirs) and the possible chemical and physical impact on well tubing and piping. EPL parameters may include glycol, methanol, metals and chlorides. Water treatment before injection may be required to achieve these levels (refer to the techniques below).
  - Inject produced water into deep underground strata, such as the original oil and gas bearing strata, after the hydrocarbon reservoir is no longer suitable for production [9]. Requires careful review of parameters including integrity of the receiving formation, engineering design, injection rate, cumulative volume of injection and injection pressure to account for, among others, potential seismic risks arising from this operation.

- Treat produced water to reduce constituents with potential environmental impacts to below acceptable EPLs:
  - Prevent prior formation of stabilised emulsions in produced water, which are typically the most difficult to treat with produced water technologies. Formation prevention can be reduced through selection of production chemicals and optimisation of chemical dosage.
  - Consider technology to prevent shearing of oil droplets during treatment, such as low shear valves and low shear pumps, since larger oil droplets are easier to separate.
  - Treat produced water using primary and/or secondary treatment techniques, which will depend on the properties of the oil/water mixture, and location-specific factors. These may include, for example [1,7,8]:
    - Gravity separators – Gravity separators remove dispersed components by relying on the density difference between water and hydrocarbon phases. Gravity separator designs include: three-phase separators; and plate separators (e.g. titled, parallel, corrugated). Gravity separators are typically used at the first stage of treatment.
    - Hydrocyclones – Hydrocyclones are generally more effective than gravity separation as a means of separating oil droplets from water and removing dispersed oil, but they do not remove dissolved components. Hydrocyclones feed the water/oil into a tube inducing a vortex, forcing denser water to the outer wall and allowing oil to form a low-pressure phase in the centre of the tube that flows out of the hydrocyclone in the reverse direction. Hydrocyclones require a drop-in pressure that may necessitate the installation of pumps. They may be followed by a degassing vessel or gas flotation unit. Multicyclones are units containing a number of hydrocyclone stages.
    - Degasser (Skimmer) - Increased efficiency of oil separation may be achieved with the addition of oil skimming facilities. A Degasser (Skimmer) is sometimes found in a secondary stage of a produced water treatment system. It is a gravity separator with the aim of reducing the dissolved gas, free oil content in a produced water stream before it is re-injected or discharged. A thin layer of oil is formed and skimmed. Removal of free gas at atmospheric conditions is important for discharged water to ensure that dissolved hydrocarbon gases are released in a controlled way.
    - Centrifuges – Centrifuges mechanically separate discrete liquid phases of differing densities by accelerating the material in a centrifugal field. As with hydrocyclones the heavier water phase migrates to the outer edge of the centrifuge leaving less dense hydrocarbons in the centre. Unlike hydrocyclones, which have no moving parts, centrifuges require rotating equipment, which increases complexity. Centrifuges allow for separation of smaller oil droplets than a hydrocyclone; however, energy consumption is higher.
    - Gas flotation – Gas floatation removes oil droplets from water by attachment to rising bubbles. These rise to the surface of the water and may be removed by skimming. Gas flotation is usually the polishing step in a multiple step procedure to remove dispersed oil with treatment prior to this stage to reduce oil in water (OIW) concentration. Gas flotation units may be categorised as:
      - Induced Gas Flotation (IGF) –Flotation gas bubbles are hydraulically or mechanically generated. The horizontal multi-stage IGF units have typically four active flotation cells. The operation of a hydraulically induced gas

flotation cell is similar to the mechanically induced gas flotation cell. However, instead of using a mechanically driven impeller to generate bubbles, a recirculated stream of clean water is mixed with gas and the mixture is injected into the flotation unit.

- Dissolved Gas Flotation (DGF) – Dissolved gas in the process stream is used to generate the gas bubbles used in floatation.
- Vertical IGF – In its simplest form, IGF is a single cell of a horizontal multi-stage IGF configuration. Vertical IGF technology incorporates between 30 seconds and 4 minutes residence time. Single stage vertical flotation units may not be as efficient for de-oiling produced water as multi cell horizontal flotation units, but vertical flotation works well in applications where horizontal flotation may not be feasible due to space and weight constraints. In the industry vertical IGFs are also referred to as Compact Flotation Units (CFUs), which is reflected in the product names of the technologies marketed by various suppliers.

- Membrane technology – Such technology is also referred to as micro-, ultra- or nano-filtration or reverse osmosis depending on the size of the contaminants requiring removal (larger to smaller respectively). Ultrafiltration is capable of removing dispersed hydrocarbons (including emulsions) while nanofiltration might additionally remove some larger dissolved hydrocarbons.
- Macro Porous Polymer Extraction (MPPE) is a fluid extraction technology that removes dissolved organics from produced water. Produced water passes through a column packed with porous polymer beads containing an extraction liquid that removes dissolved oil and organics. Periodic stripping of hydrocarbons from the extraction liquid is then performed. MPPE has a good track record for reducing organic constituents to low levels, including >99% removal of BTEX and polycyclic aromatic hydrocarbons (PAHs), and >95% removal of aliphatics of chain lengths <C20. Removals have been less effective for aliphatics of chain lengths >C20.
- Coalescers - Coalescence uses oleophilic (oil loving) media such as polypropylene or Teflon to catch oil droplets as produced water is passed across its surface. Larger oil droplets are then much easier to separate. Coalescing is usually combined with gravity separation, by being installed as a coalescing pack at the inlet to a gravity separator vessel, or by coating the plates in a tilted plate separator with oleophilic material.
- Adsorption (media) filtration – Adsorption filters may be applied for the removal of dispersed and dissolved hydrocarbons. Upstream treatment is required to remove in advance any dispersed oil that may be present in the produced water. Filters must be replaced frequently and their media (e.g. cellulose) cannot always be recycled, although some carbon activated filters may be partially recycled. Media for this purpose also include walnut and pecan shells. The disposal of spent absorbents creates solid waste management issues.
- Steam stripping - Steam stripping is used to remove BTEX and can also remove dispersed hydrocarbons. Produced water is directed to a packed column and brought into contact with steam. Owing to the high hydrocarbon content, the steam and hydrocarbon vapours condense and separate easily. The technique is reliable and proven but energy consumption is relatively high, although this can be offset using waste heat from gas turbines. A requirement for steam stripping is that a constant flow is maintained or make up water is added.

- Discharge produced water after treatment, and only in compliance with national legislation and/or permit conditions:
  - Ensure that effluent discharge to surface water or to land does not result in significant impact on human health and environmental receptors [10].
  - For discharge to surface water or to land, taking into account the ecological status of the receiving surface water, the indicative EPLs shown in Table 15.1 apply [2, 11].
  - For discharges to coastal waters or to sea, refer to Offshore Activity 5 (Section 23).

Table 15.1 EPLs for Discharge to Surface Water or Land [2,11,12]

Parameter	Unit	EPL *
Total hydrocarbon content	mg/l	10
pH		6-9
BOD	mg/l	25
COD	mg/l	30-125
TSS	mg/l	5-35
Phenols	mg/l	0.5
Sulfides	mg/l	1
Heavy metals (total)*	mg/l	5
Chlorides	mg/l	600 (average) 1200 (maximum)

* EPL values are based on [2] and [8]. Where reference [10] includes a lower value for the same parameter, this is included as the lower end of the range. Figures are monthly averages.
** Heavy metals include: arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, vanadium, and zinc. In reference [10] there are BAT-AEL values for specific heavy metals, however, applicability for hydrocarbon extraction facilities has not been assessed.

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16. Onshore Activity 13: Environmental Monitoring

16.1 Summary of the Activity

Monitoring may be performed for any onshore hydrocarbon activities that have been identified as having potential environmental impacts. Environmental monitoring can involve direct or indirect measurement of emissions, discharges, and resource use applicable to operations and process parameters, as well as of impacts on environmental receptors.

Monitoring activities are undertaken throughout facility or project operational life, i.e. from before activities commence to establish baselines, as well as during, development, production and decommissioning. Monitoring provides insight to support management and ultimately reduce impacts. Appropriate environmental monitoring and control equipment can, in some cases, allow operational improvements and assist in checking compliance with permit conditions while activities are underway.

Monitoring may include, for example:

- Collection of information and data for assessing baseline conditions (e.g. at the approval stage of a development) and for undertaking environmental assessments (e.g. during design and operations).
- Measuring and/or estimating environmental baseline parameters, in order to develop a robust understanding of the environment under consideration including known sensitivities, and measuring and/or estimating potential environmental impacts (e.g. during production), such as:
  - Air quality and air emissions - Combustion products and non-combusted methane from waste gas flares, gas engines or turbines, bath heaters and other on-site combustion devices; and fugitive methane and NMVOC emissions from process systems;
  - Water quality and quantity - Constituents of produced water and flowback fluids (e.g. heavy metals, hydrocarbons, sulphides, chlorides, TDS, NORM); quantities dispatched off-site for disposal; discharge points to surface water or groundwater; and temperature of the water discharged to surface waters;
  - Terrestrial parameters - Quality of soil, surface water and groundwater; hydrogeology, evidence of historical pollution waste streams; induced seismicity and baseline seismic monitoring; and effects on local biotopes; and
  - Physical presence - Levels of noise and vibration from a facility (e.g. caused by compressors, pipelines, pumps, diesel generators, flares, drives), light emissions, odours, land take requirements, etc.

Monitoring parameters selected against each of the lifecycle phases should reflect the pollutants and activities of concern associated with proposed and actual operations and should address both the monitoring of emissions and discharges as well as impacts on the receiving environment. Monitoring should be carried out with a clear overall objective, and a strategy that considers parameters including ecosystem context, location, contaminant properties, and levels of detectable change in the receiving environment.

The focus of this Section is on relevant monitoring programmes and activities in onshore production facilities.

16.2 Best Risk Management Approaches

The best risk management approaches for environmental monitoring are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for environmental monitoring (Section 3.4.2).
- Ensure that environmental monitoring is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Section 3).
- Develop and implement a risk-based Environmental Monitoring Programme, covering all activities and aspects that have potential environmental impacts, and includes elements as set out in the environmental risk assessment (see above). An Environmental Monitoring Programme should include indicative elements:
  - For each project phase:
    - Early development - Carry out baseline monitoring at and in the vicinity of the site as part of an Environmental Baseline Study in order to differentiate between existing ambient conditions and project-related impact (Section 3.5.3).
    - Design/Development - Collect additional information and data as part of EIA (Section 3.5.4). The type, frequency and duration of environmental monitoring requires a site-specific approach that would normally be set out in the EIA and may take as its basis the Environmental Baseline Study.
    - Production – Ensure that the monitoring is addressed in the production phase, during which it should become a routine activity typically included within an Environmental Management System / HSE Management System (see above).
    - Decommissioning - Collect environmental data to establish the pre-decommissioning baseline, in a similar manner to the Environmental Baseline Study outlined above (Section 3.5.3).
  - Overarching objectives [1,2,3]:
    - Establish the types and quantities of substances planned as emissions and/or discharges from the facility.
    - Establish the spatial distribution and extent of emissions and discharges expected, and their impacts on the environment, supported as necessary by environmental modelling (Section 3.5.6).
    - Establish environmental baseline through initial survey (including analysis of historical data for existing assets).
    - Establish temporal trends to estimate the magnitude of environmental changes over time with respect to this baseline. Emissions from highly variable processes may need to be sampled more frequently or through composite methods. Emissions monitoring frequency and duration may also range from continuous for some combustion process operating parameters or inputs (e.g. the quality of fuel) to less frequent, monthly, quarterly or yearly tests.
    - Determine and implement required measures for monitoring identified emissions and discharges, and their associated environmental impacts.

- Undertake continual review to identify unforeseen impacts and new issues, including follow-up survey(s) to monitor environmental changes.
- Select monitoring parameters based on a risk assessment approach [4], that considers at least the following risk factors [5]:
  - Size and type of the installation, which may determine its environmental impact.
  - Complexity of sources (number and diversity, source characteristics (e.g. area sources, channelled emissions, peak emissions)).
  - Complexity of the process, which may increase the number of potential malfunctions.
  - Possible environmental and human health effects resulting from hazards taking into account their level of risk.
  - Proximity of the hazard to sensitive environmental receptors.
  - Presence of natural hazards, such as geological, hydrological, meteorological or marine factors.
  - Past performance of the installation and its management.

- Key considerations for monitoring source releases / emissions from a facility:
  - Apply standard CEN / ISO measurement techniques which are considered best practice and are recommended to ensure high quality results.
  - For air emissions, consider in the planning stages as to how data relating to fuel flow, gas turbine load parameters, gas composition data, and stack velocity are to be monitored and recorded in parallel with monitoring (direct or indirect) of emission concentrations.
  - Identify main emission and discharge sources that warrant monitoring, and the minor sources that may either not require monitoring or could be monitored less frequently or monitored using portable devices.
  - Characterise emissions profiles over a range of representative operating conditions, and for relevant fuel types (i.e. gas and/or diesel), in line with the relevant national and local legislation.
- Key considerations for monitoring environmental impacts (i.e. on receiving environment) [6]:
  - Ensure data generated through the monitoring programme is adequately representative for the processes and activities being addressed over time.
  - Consider the sensitivity of the receiving environment.
  - Establish monitoring locations based on the interpretation of the results of scientific methods and mathematical models, where applicable, to assess the site conditions at regular intervals, compare the results to the environmental baseline study and to measure the impacts of the activities and assess the effectiveness of mitigation measure.
  - Apply national or international methods for sample collection and analysis, such as those published by CEN/ISO or others as appropriate (e.g. OSPAR). Sampling

should be conducted by, or under the supervision of, appropriately experienced individuals.

- Apply sampling and analysis quality assurance / quality control (QA/QC) plans, and document to ensure that data quality is adequate for the intended data use (e.g. method detection limits are below levels of concern). Monitoring reports should include QA/QC documentation where appropriate.
- Have an understanding of the level of uncertainty of all monitoring equipment and methods, in percentage terms (e.g. +/-10%). This will vary depending on type of monitoring and should be accounted for when reporting emissions and discharges.

- For new facilities and modifications to existing facilities, ensure engineering design accounts for inherent safety and the minimisation of potential for environmental impact by including monitoring equipment and procedures for emissions and discharges (refer to BAT below) (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).

16.3 Best Available Techniques

The following techniques are considered BAT for environmental monitoring:

16.3.1 Design

- Provide sampling ports on combustion equipment, where safe to do so, including gas turbines, generators, etc. for sampling of exhaust gas, and concentrations of CO, SO_x, NO_x. Sampling ports provide the location at which portable gas detectors are inserted to monitor emissions.
- Quantify fugitive emissions in design based on the number of components in hydrocarbon service and generic emission factors. Once in operation these should be revised, and facility-specific factors used in place of the default design factors.
- Provide equipment for the measurement of produced water volume, both prior to either reinjection and/or discharge in different operating conditions.
- Perform OIW analysis (e.g. using OIW analyser or laboratory analysis) as well as providing manual sampling points at the point of discharge, for analysing OIW concentrations in produced water and other discharges if required. Analysers should be installed after the last stage of treatment prior to any discharge, and before any commingling or recycle loop. OIW manual sampling points should be installed on the discharge line prior to discharge. Drainage discharge flow meters should also be installed on this line.

16.3.2 Operations

- Monitor flare emissions by calculation and/or direct measurement (where applicable). An alternative to direct measurement of flare gas flow is to measure or otherwise determine all contributory flows into the flare gas system. Analysis may be performed to determine flare gas composition.
- Monitor emissions to air by calculation and/or direct measurement, including for example H_2S, BTEX, NOx, SO_2, PM, VOC, CO, CO_2, CH_4 [5,7] from:

  - Point source emissions to air from combustion emissions and gas flares. Refer to Onshore Activity 8 (Section 11).
  - Fugitive emissions.
- Monitor diesel fuel and fuel gas usage (if applicable). Report diesel and fuel gas usage and emissions to the Regulatory Authority once a facility is operational.
- Monitor discharges to water including heavy metals (arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, vanadium, zinc), hydrocarbons, sulphides, chlorides, and TDS [5,7,8].
- Monitor soil and groundwater using pollution risk leak detection system; groundwater monitoring grid and including for example temperature, hydrocarbons, metals, dissolved oxygen, and TDS.
- Monitor waste streams including quantity, waste type/category, chemical composition of waste streams and radioactive substance monitoring (aqueous and solid radioactive waste) [1].
- Monitor noise and vibration in areas where prior assessment indicates potential disturbance to local populations and/or sensitive ecosystems [9].
- Assess odour levels in terms of impacts on surrounding areas where prior assessment indicates potential disturbance to local populations and/or sensitive ecosystems.
- Establish an appropriate monitoring scheme for verification of the casing and cementing programme against expected conditions (e.g. pressure monitoring and cement placement monitoring as well as well integrity testing).
- Monitor well integrity during drilling by continuous pressure monitoring of casing pressure in inner casings.
- Implement a risk-based programme of post-decommissioning monitoring.
- Implement a risk-based programme of subsidence monitoring during the production phase (diminishing underground pressure) with the potential for induced seismicity.
- Monitor seismic activity (e.g. for hydraulic fracturing) including:
  - Seismic monitoring station network [10].
  - Fracture growth assessments, injectivity monitoring and downhole micro-seismic monitoring arrays.
  - *Traffic Light System (TLS)*, *Response Plan* or *Area of Interest* approaches [11,12,13]:
    - TLS – TLS is a set of operational instructions commonly developed by the Regulatory Authority in conjunction with the organisation conducting well operations. Its purpose is to mitigate the observed seismic activity when specific conditions exist or observations are made. Under a typical TLS operating system, a well (or project) will be under green, yellow or red operating conditions, depending on specific observations related to the well and to seismicity conditions around the well. TLS operates under pre-determined numerical thresholds, commonly relating to magnitudes of seismic events and their proximity to wells.
    - Response Plan - including communication needs around induced seismicity, reflecting the actions required and the technical requirements of the risk management plan (e.g. Subsurface Information Plan – Section 4.2).

- Area of Interest - An alternative approach used by regulators is the definition of an Area of Interest. If operations are conducted within the specific Area of Interest, constraints on scope of operations are pre-defined. In arrays surrounding an area of interest seismometers are typically deployed to monitor potential earthquake activity or provide baseline seismicity data to monitor potential earthquake activity or provide baseline seismicity data.

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Part Four: Guidance for Offshore Activities

17. Offshore Activity 1: Handling of Drill Cuttings and Drilling Muds

17.1 Summary of the Activity and Potential Environmental Impacts

Drilling of hydrocarbon wells as well as the drilling of water injection, gas lift and disposal wells, generates drill cuttings, which are particles of crushed rock produced by the action of the drill bit as it penetrates the earth. The chemical and mineral composition of drill cuttings reflects that of the rock layers being penetrated by the drill. Also used as part of the drilling process are drilling fluids (or muds), which serve multiple purposes including to carry drill cuttings to the surface, to lubricate and cool the drill bit, and to control well pressures as part of safe drilling operations.

Drilling fluids are liquid mixtures of fine-grained solids, inorganic salts, and organic compounds dissolved or dispersed/suspended in a 'continuous phase' (the base fluid) which may be water or an organic liquid. Classification of drilling fluids is based on the primary component of the continuous phase (water, oil or synthetic hydrocarbons) [1]:

- Water-based drilling fluids (WBDFs) are formulated mixtures of clays, natural and synthetic organic polymers, mineral weighting agents, and other additives dissolved or suspended in seawater or brine. WBDFs (or "water-based muds") are the most widely used, are generally less expensive than other systems and are the preferred option from an environmental perspective, although they are not necessarily suitable for all formations (see below); and
- Non-aqueous drilling fluids (NADF) are emulsions in which the continuous phase is an organic base fluid ("oil-based muds" or "synthetic based muds"), with water and chemicals as the internal phase. Water, containing inorganic salt and oil-soluble or oil dispersible additives is dispersed into the non-aqueous continuous phase and the resulting emulsion is stabilised with emulsifier.

The choice of water or oil/synthetic-based fluids (muds) is dependent on the technical characteristics of a well drilling operation. Use of mud with suitable properties ensures that a safe drilling margin is maintained whereby mud properties (e.g. weight) are capable of controlling pore pressure and formation fluids while not fracturing the formation, thus maintaining well control. The use of oil-based muds is sometimes preferred for drilling through production zones containing hydrocarbons, and for technically challenging situations, including:

- Demanding drilling operations, including highly deviated, extended reach, and horizontal wells;
- Where higher lubrication and lower friction are required than is typically offered by water-based muds;
- To enable drilling through rock that would otherwise swell and disperse in water based mud (e.g. clays);
- To facilitate deeper drilling in high-temperature environments that would dehydrate water-based drilling muds and impact hole stability; and
- To enable drilling through water-soluble geologies.

Drill cuttings become contaminated with both the residues of drilling muds and hydrocarbons from the well, and other potential contaminants e.g. reservoir heavy metals and/or NORM. In addition, they also contain chemicals used during the drilling and well completion processes. They must therefore be handled and treated/disposed of accordingly, either through: offshore injection; onshore disposal and beneficial reuse; or

offshore discharge to sea. Discharge to sea is the most common practice for cuttings from wells drilled using water based mud.

Discharge to sea of drill cuttings poses a potential risk to the environment, and hence treatment is typically required to reduce their hydrocarbon content prior to discharge. Cuttings that fail to meet the discharge requirements, and for which no offshore injection is possible, may be stored as waste and returned to shore for processing prior to onshore disposal or recycling (see Onshore Activity 4). Alternatively, cuttings may be re-injected into a dedicated disposal well which is later decommissioned. Chemicals that may be discharged in drilling muds and on drill cuttings are covered as part of offshore chemical regulations and requirements detailed in Offshore Activity 3 (Section 19).

Subject to geographical factors, and cutting characteristics, drill cuttings discharged to sea have the potential to form discrete piles on the seafloor adjacent to the hydrocarbons operation, and/or spread up to several kilometres from the well site and be deposited on the seafloor. They may also remain in suspension.

This activity considers the operational handling of drill cuttings and drilling muds, including management of any planned discharges into the marine environment. It does not consider unintended releases of drill cuttings and drilling mud to the environment – such releases are considered under Offshore Activity 3 (Section 19).

17.2 Best Risk Management Approaches

The best risk management approaches for the handling of drill cuttings and drilling muds are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for handling of drill cuttings/muds (Section 3.4.2).
- Ensure engineering design for handling of drill cuttings/muds accounts for inherent safety aspects and the minimisation of potential for environmental impact and exposure to hazardous materials in the event of either a planned discharge or unintended release of drill cuttings/drilling mud (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- For geographical areas where no previous environmental baseline survey has been performed, carry out an environmental baseline survey prior to drilling. Undertake risk-based monitoring of impacts of discharged cuttings against this baseline, e.g. physical and biological sampling and analysis of water column, benthos and sediments (Section 3.5.3) [2].
- Ensure that the handling of drill cuttings and drilling muds during offshore operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7), including:
  - Estimating intended discharges of mud and cuttings in terms of volumes and tonnage expected.
  - Assessing drilling muds based on their properties, and the receiving environment, and characterise drill cuttings to arrive at an understanding of environmental risk.
  - Performing progress monitoring on 'substitution chemicals' on a regular basis summarising chemicals still to be replaced and justification for continued use and / or discharge (see also Section 23).

- Where it is planned to discharge drill cuttings into the marine environment, perform analysis as part of a specialist technical studies (see Section 3.5.6 and Section 23) that may cover, for example:
  - Well design to minimise cuttings volumes, in line with safety margin(s) for well drilling (e.g. slimhole, branched and batch drilling, "drill and drive", toe driven conductor) [1].
  - Design of collection and treatment system on facility for used muds, and/or systems to return waste to shore, and system permitting backloading of mud to supply boat [1].
  - Modelling of fate of mud-contaminated cuttings in the marine environment, to understand potential impacts, particularly when drilling occurs in a new area, or an area with known environmental sensitivities.
  - Sampling to monitor and record all drilling mud use and mud and cuttings discharge, as well as changes in the receiving environment. Refer also to Offshore Activity 10 (Section 26).
- Implement additional approaches as considered necessary to manage risks for specific operations, including but not limited to:
  - Select the appropriate drilling mud for the required application, avoiding the use of oil-based muds where possible. If not possible, only use oil-based muds that are at or below toxicity levels consistent with permits issued to the hydrocarbons organisations by the Regulatory Authority.
  - Do not dispose of whole OBM (i.e. that which is not adhered to or mixed with drill cuttings) to sea [3].
  - Do not mix OBM with cuttings for the purpose of disposal [3].
  - Do not use diesel oil-based muds [3].
  - Do not use any OBM in the top hole section of wells, except where exemptions are granted by the Regulatory Authority for geological or safety reasons.
  - For cuttings with OBM, consider (a) transfer to shore; (b) slurrification and injection; (c) treatment for oil content prior to discharge [1]. Option (c) should only be applied in cases where infrastructure is available offshore to treat cuttings prior to discharge to sea to meet performance standards for BFROC (refer to EPL below).
  - Avoid discharge of mud and cuttings to sea in areas which prior modelling, risk based studies, or local designations determine to be sensitive and/or protected [4].
  - If cuttings discharge to sea is taking place while drilling through a hydrocarbon-bearing reservoir, take samples of cuttings for analysis to determine the crude oil content. Methods of sample analysis include Retort Analysis, Gas Chromatography – Mass Spectrometry (GC-MS), Gas Chromatography Flame Ionisation Detection (GC-FID) and Fourier Transform Infrared Spectroscopy (FT-IR) [5].
  - Discharge to achieve maximum dispersion of solids on the seabed and avoid smothering benthic ecosystems, e.g. discharge via a caisson [1].

17.3 Best Available Techniques

Where discharge of cuttings to sea is permitted by the Regulatory Authority, EPLs associated with the application of BAT for discharges to sea of NADF (oil-based mud) on drill cuttings are shown in Table 17.1 [3]:

Table 17.1 EPL for BFROC Discharged to the Environment

Parameter	EPL [3]
Hydrocarbon (NADF) content	< 1% Base fluid retained on cuttings (BFROC)

Methods of sample analysis include the BEIS IR Method [5], carried out offshore during the discharge operation. EPLs can be achieved by applying BAT comprising one or a combination of the techniques listed below, or alternatives that achieve equivalent performance. The following are listed in order of preference:

- Offshore reuse – Reuse of mud offshore to the maximum extent possible is preferred prior to consideration of discharge.
- Offshore injection – Offshore injection of drill cuttings may be used in locations in which suitable disposal wells are available. Drill cuttings and retained muds are injected into suitable subterranean geological formations [2]. This involves reducing cuttings particle size at surface to produce a slurry which is then hydraulically injected into a subsurface formation that is receptive and permanently isolated at a safe depth to prevent propagation to the surface.
- Onshore Disposal or Reuse – Drill cuttings and muds may be collected and transported onshore for treatment prior to disposal or beneficial reuse, using methods such as:
  - Thermal treatment – Thermal desorption is primarily used to separate hydrocarbons from cuttings drilled with oil-based mud Thermal desorption can be direct (where combustion is used to generate heat in the same chamber as the desorption) or indirect (where heat is generated separately from the desorption chamber) or based on mechanical friction. Most thermal desorption systems used in the hydrocarbons industry are indirect or friction-based systems (refer also to below).
  - Biological treatment – Used for composting of residues on drill cuttings after being transported onshore. Composting is a controlled, biological treatment process whereby organic substances are converted by microorganisms to innocuous, stabilised by-products. Successful composting of drill cuttings generally requires blending of the cuttings with organic materials to provide the appropriate proportions of carbon, nitrogen, and moisture, all of which are required for the composting process. Addition of organic material will increase overall volume of waste.
  - Beneficial use – Mud/cuttings may be processed for beneficial use, including use in construction materials, cement kiln feedstock, etc. This may require considerable pre-treatment to meet applicable specifications; and requires approval by the Regulatory Authority and end-users which may be costly and time-consuming.
  - Other disposal – Methods include incineration, land spreading and landfill as a last resort.
- Offshore discharge – Discharge to sea of drill cuttings and drilling muds may occur where environmental regulations permit ocean discharge, following suitable treatment to reduce oil concentrations on cuttings to acceptable levels as permitted by the Regulatory Authority. Treatment for oil based mud may use thermal desorption (e.g. thermomechanical cuttings cleaner – TCC) technology to separate hydrocarbons from cuttings. Cuttings treatment may, however, be impractical offshore (e.g. due to weight/space restrictions) and hence oil/synthetic based mud/cuttings may instead be returned to shore for treatment (refer to above).

Additional guidance in this area includes [6-10].

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18. Offshore Activity 2: Risk Management for Handling and Storage of Hydrocarbons

18.1 Summary of the Activity and Potential Environmental Impacts

The handling and storage of hydrocarbons – both oil and gas – occurs offshore during exploration and production as part of operations as diverse as:

- Well drilling and completion – During drilling of exploration and development wells, hydrocarbons from a reservoir may circulate to the surface as part of the drilling process;
- Production – Hydrocarbons are extracted from the reservoir via the well, wellhead flowlines and risers and onto a facility for processing, storage and offloading/export. During production, hydrocarbon handling and storage occurs in a variety of ways within a process system that includes plant, equipment and pipework;
- Offloading – Hydrocarbons may be stored in bulk on a facility for regular offloading by tanker or transferred continuously from the facility via a dedicated pipeline;
- Day to day operations for hydrocarbon utilities – Hydrocarbons are loaded, stored and handled for daily requirements and specific operations. Examples include diesel fuel (generators, pumps, etc.) and helifuel.

The dynamic nature of offshore operations means that hydrocarbons on a facility are often in a continual state of onloading, offloading and transfer at any given time. The term "handling" refers to the loading onto a facility of hydrocarbons and their transfer while on the facility as required for specific operations. "Storage" refers to the temporary holding of hydrocarbons within fixed containment on a facility.

All of the above described operations carry a risk of unintended release of hydrocarbons to the environment. This may occur on the facility (e.g. a release from process equipment) or off the facility (e.g. a loss of containment from the well, pipelines, or during offloading. Hydrocarbon releases can vary in size from small volume leaks (e.g. from storage tanks, pumps, hoses, valves, flanges, etc.) to very large spills.

This activity refers only to unintended releases of liquid hydrocarbons. Gaseous emissions are covered in Offshore Activity 6 (Section 22). A variety of operations (e.g. equipment maintenance) may also result in planned discharges of hydrocarbons which are collected by the facility drains system. Hydrocarbon contaminated drain water is treated and discharged to sea once hydrocarbon content is reduced below an acceptable threshold. Such releases are covered in Offshore Activity 8 (Section 24). In addition, produced water releases represent a planned discharge of hydrocarbons and are covered in Offshore Activity 7 (Section 23).

Unintended releases may result from, for example, failure of equipment, human error, incidents or accidents. Large spills to the marine environment in particular can result in adverse effects on marine species and their habitats in the water column and on the seafloor. Sufficiently large spills close to the coast may also have terrestrial impacts. EU Directives consider environmental consequences in terms of environmental impact, severity of harm and recovery time, including to water, land, protected species and natural habitats as well as to human health [1].

A pragmatic way of understanding the risk of unintended liquid hydrocarbon releases is by considering their magnitude in terms of spill size, likelihood based on historical precedent and industry knowledge and scale of response. Offshore hydrocarbon spills and response may be categorised using the IPIECA [2] "tiered" approach. Under this, Tier 1 is where operators can themselves mitigate spills that are typically of an

operational nature, and occurring on or near their own facility, using local resources. Tier 2 is where extra resources may be required from national or regional providers to increase response capacity or draw on more specialist expertise. Tier 3 is where the response requires resources that are globally available to supplement tiers 1 and 2. The tier of response for a given spill size/type may vary depending on e.g. the geographical location and availability of resources to respond.

In terms of managing risk, unintended hydrocarbon releases are typically considered in terms of both their safety and environmental consequences, and hence most of the existing regulations and guidance for safety risk management are also applicable to environmental risk. The Offshore Safety Directive [3] provides specific definitions for events of a magnitude such as to be considered as "major accidents" and "major environmental incidents" (Section 3.2).

The TWG concluded that the Guidance Document should cover best risk management approaches, but not BAT for unintended releases of hydrocarbons. Therefore, there is no Section on BAT for this activity.

18.2 Best Risk Management Approaches

The best risk management approaches for the handling and storage of hydrocarbons are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels and contains procedures for hydrocarbon storage and handling (Section 3.4.2).
- For new facilities and modifications to existing facilities, ensure engineering design for handling, storage, production and export of hydrocarbons accounts for inherent safety and minimisation of potential for environmental impact, in the event of either a planned or unintended release (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Ensure that the management of hydrocarbons stored and handled on the facility is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- Have in place a Spill Contingency Plan for the emergency response management of spills of hydrocarbons to the marine environment (Section 3.5.13). Relevant guidance such as [2] should be taken into account.
- Implement additional approaches as considered necessary to manage risks of unintended releases for specific operations to acceptable levels. While individual approaches are not detailed here, some examples are outlined along with insight into key management measures and a (non-exhaustive) list of possible SECEs [4]. In all cases, these summaries assume that an organisation already has a management system in place and has considered best practice engineering design.
    - Well drilling and completion
        - Well blowout is a risk normally considered to be of remote likelihood, but with the potential for high severity consequences. SECEs typically in place to manage this hazard include: Primary and Secondary Well Control, Well Monitoring, and undertaking relief well planning. Guidance in this area includes [5-18].

- Well testing may require flaring which could result in the unintended release of liquid hydrocarbons (dropout) from flare. If such an event occurs, the best risk management approach is to more carefully control or cease well testing operations if it is safe to do so and report the event as a spill to the Regulatory Authority. The Spill Contingency Plan for the facility should be invoked (Section 3.5.13).

- Production
  - Unintended release of hydrocarbons during transfer to the facility via the marine riser has potential for high severity consequences, as does a large hydrocarbon release on facility topsides or from cargo storage tanks. SECEs typically in place to manage these hazards include: Hazardous Material Containment; Emergency Shutdown Systems; and Facility Structure. Guidance in this area includes [19-47].
  - Process upset conditions requiring depressurisation and blowdown may lead to a requirement for flaring which could lead to unintended release of liquid hydrocarbons (dropout) from flare. If such an event occurs, the best risk management approach is to more carefully control or cease operations if it is safe to do so, and report the event as a spill to the Regulatory Authority. The Spill Contingency Plan for the facility should be invoked (Section 3.5.13).
  - Integrity of hydrocarbon storage may be monitored, e.g. using pressure and level monitoring equipment, in order to detect unintended releases due to loss of containment.
- Offloading
  - Unintended hydrocarbon releases during crude offloading have the potential for medium severity environmental consequences. SECEs typically in place to manage this hazard include: Hazardous Material Containment; and Emergency Shutdown Systems. Guidance in this area includes [48-52].
  - The best risk management approach for offloading is to develop an offloading strategy that considers types of offload (quantities, timing, etc.), types of vessel to service offloading, export pipeline options, restricted/prohibited loading zones, offloading equipment, offloading procedure (approach, connect, loading, disconnect, departure, weather operating windows), and potential safety and environmental hazards and risks.
- Day-to-day operations
  - Unintended release of hydrocarbons such as the diesel inventory on the facility may have medium-high severity consequences in the event of a large release, e.g. loss of diesel inventory from hull tanks or loss of crude oil from a separator. Measures in place for management of these hazards form an important part of a facility's containment strategy. SECEs typically in place to manage this hazard include: Hazardous Material Containment; and Facility Structure.
  - The best risk management approach for assuring ongoing operational effectiveness is to record reasons for, and consequences of, all unintended releases of hydrocarbons occurring during day-to-day operations, in order to take the necessary corrective actions to reduce release frequency [53].

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19. Offshore Activity 3: Risk Management for Handling and Storage of Chemicals

19.1 Summary of the Activity and Potential Environmental Impacts

Handling and storage of chemicals is required for a variety of offshore operations during exploration and production. Handling refers to the loading onto a facility of chemicals and their transfer while on the facility as required for specific operations. Storage refers to the temporary holding of chemicals within fixed containment on a facility. Following use, chemicals should where possible be collected, stored as waste, and transported onshore for treatment and disposal.

The use of chemicals poses risks to the environment in relation to both planned discharges and unintended releases to the marine environment, which may lead to adverse effects on species in the water column and on the seafloor. In this context planned discharges are those expected to take place during normal operations, while unintended releases are unexpected and may occur due to, for example, failure of equipment, loss of containment from storage facilities, human error, incidents and accidents.

The use of chemicals offshore occurs in the following operations:

- Well drilling, well interventions and completions – Chemicals are used during drilling and well completions and examples (non-exhaustive) include [1]:
  - Cement, used to secure drilling casing in place, to protect and seal the wellbore.
  - Weighting materials - Increase the density of drilling mud, and balance formation pressures, as part of well control. Includes barite, hematite, calcite, and ilmenite.
  - Viscosifiers - Increase viscosity of mud to suspend cuttings and weighting materials in drilling mud. Includes bentonite or attapulgite clay, xanthan, carboxymethyl cellulose, and other polymers.
  - Thinners, dispersants, and temperature stability agents - Deflocculate clays to optimise viscosity and gel strength of drilling mud. Includes tannins, polyphosphates, lignite, and lignosulfonates.
  - Flocculants - Increase viscosity and gel strength of clays or clarify or de-water low-solids drilling muds. Includes inorganic salts, hydrated lime, gypsum, sodium carbonate and bicarbonate, sodium tetraphosphate, and acrylamide-based polymers.
  - Filtrate reducers - Decrease fluid loss to the formation through the filter cake on the wellbore wall. Includes bentonite clay, lignite, sodium-carboxymethyl cellulose, polyacrylate, and starch.
  - Alkalinity, pH control additives - Optimise pH and alkalinity of drilling mud, controlling mud properties. Includes Lime (CaO), caustic soda (NaOH), soda ash (Na_2CO_3), sodium bicarbonate ($NaHCO_3$), and other bases as well as acids.
  - Lost circulation materials - Plug leaks in the well bore wall, preventing loss of drilling mud to the formation. Includes natural fibrous materials, inorganic solids, and inert insoluble solids.
  - Lubricants - Reduce torque and drag on the drill string. Includes oils, synthetic liquids, graphite, surfactants, glycols, and glycerine.

- Shale control materials - Control hydration of shales that causes swelling and dispersion of shale, collapsing the wellbore wall. Includes soluble calcium and potassium salts, other inorganic salts, and organics such as glycols.
- Emulsifiers and surfactants - Facilitate formation of stable dispersion of insoluble liquids in water phase of mud. Includes anionic, cationic, or non-ionic detergents, soaps, organic acids, and water-based detergents.
- Bactericides and other biocides - Prevent biodegradation of organic additives. Includes glutaraldehyde and other aldehydes.
- Defoamers - Reduce mud foaming. Includes alcohols, silicones, aluminium stearate ($C_{54}H_{105}AlO_6$), and alkyl phosphates.
- Pipe-freeing agents - Prevent pipe from sticking in wellbore or used to free stuck pipe. Includes detergents, soaps, oils, and surfactants.
- Calcium reducers - Counteract effects of calcium from seawater, cement, formation anhydrites, and gypsum on mud properties. Includes sodium carbonate and bicarbonate (Na_2CO_3 and $NaHCO_3$), sodium hydroxide (NaOH), and polyphosphates.
- Corrosion inhibitors - Prevent corrosion of drill string by formation acids and acid gases. Includes amines, phosphates, and other specialty mixtures.
- Temperature stability agents - Increase stability of mud dispersions, emulsion and rheological properties at high temperatures. Includes acrylic or sulfonated polymers or copolymers, lignite, lignosulfonate, and tannins.
- Drilling muds and well completion fluids supplemented with chemical additives such as corrosion inhibitor, biocide, oxygen scavenger, acids, glycol, weighting materials, salt, viscosifier, etc.

- Production – Chemicals are also used in a variety of applications during production. They may, for example, be injected into the process stream, used as pipeline chemicals, gas treatment chemicals, or utility chemicals, as well as those added to export flow and arriving from upstream facilities. These chemicals include:
  - Corrosion inhibitors - Prevent corrosion of process equipment and pipework by formation acids and acid gases. Includes amines, phosphates, and other specialty mixtures.
  - Scale inhibitors - Prevent formation of scale from blocking/hindering fluid flow through pipelines, valves, and pumps, both topsides and subsea. Includes acrylic acid polymers, maleic acid polymers and phosphonates.
  - Demulsifiers – Break crude oil emulsion into oil and water phases. Includes xylene, heavy aromatic naphtha (HAN), Isopropanol, methanol, 2-ethylhexanol and diesel.
  - Biocides – Prevent microbiologically influenced corrosion for example in crude rundown and slops tanks. Includes antibacterial, antifungal and anti-algae formulations.
  - Dehydration chemicals – Prevent corrosion and free-water accumulation. Includes monoethylene glycol (MEG), diethylene glycol (DEG), triethylene glycol (TEG) and hydrate prevention chemicals (e.g. methanol).
  - Others including water clarifiers, antifoam, and scale dissolver.
- Day-to-day operations (covering multiple phases) – Chemicals are bulk loaded, stored and handled for daily requirements and specific operations offshore in both exploration and

production phases offshore. Examples include hydraulic fluid, chemicals used for maintenance, detergents, etc.

- Chemicals may also be used during other phases, such as well workover activities.

This activity covers all chemical management offshore, including planned discharges and unintended releases from all offshore activities in the Guidance Document. Specifically, the activities involving chemicals to which this Section refers are:

- Handling of drill cuttings and drilling muds – Offshore Activity 1 (Section 17);
- Produced water handling and management – Offshore Activity 7 (Section 23); and
- Management of Drain water – Offshore Activity 8 (Section 24).

Unintended chemical releases are typically considered in terms of both their safety and environment consequences, and hence most of the existing regulations and guidance for safety risk management can also be applied to environmental risk. Unintended releases of chemicals could occur for example during the following operations:

- Release during transfer of chemicals onto the facility (e.g. during lift from supply vessel);
- Loss of containment from storage or handling of chemicals (and chemical waste) to point of topsides/subsea use (e.g. from pipework, tote tank);
- Loss of containment during drilling/completions (e.g. loss of well control, drilling mud spill, etc.); or
- Spillages during routine day to day operations.

The causes of the above scenarios may be diverse and include organisational, operational errors, equipment failure, and escalation due to a preceding event.

The most widely adopted system in place to assess the potential impact of planned offshore chemical discharges to the marine environment in the EU is the OSPAR Harmonised Mandatory Control System (HMCS) [2,3]. This system promotes the shift towards the use of less hazardous or preferably non-hazardous substances. OSPAR makes clear which chemicals are covered or otherwise by the system [4].

The OSPAR [5] Hazardous Substances Strategy considers that organisations should aim for a continuous reduction in discharges of hazardous substances via produced water with the ultimate aim to achieve near background concentrations in the marine environment for naturally occurring substances and close to zero concentrations of synthetic substances. OSPAR Recommendation 2006/3 [6] also requires that organisations phase out the discharge of offshore chemicals that are, or which contain substances, identified as candidates for substitution, except for those chemicals where, despite considerable efforts, it can be demonstrated that this is not feasible due to technical or safety reasons.

REACH Regulation 1907/2006 [7] requires the operator using a chemical substance either on its own or in a mixture, to implement its safe use on site. The facility should retain an (extended) Safety Data Sheet (SDS) or equivalent information for each chemical held, with exposure scenarios containing operational conditions and risk management measures for safe use, and to facilitate the training of workers in the relevant risk assessment procedures (where such an eSDS is available). REACH is directly linked to CLP Regulation 1272/2008 [8] which establishes hazard and precautionary statements.

19.2 Best Risk Management Approaches

The best risk management approaches for the handling and storage of chemicals are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for chemicals handling and storage (Section 3.4.2).
- Conduct a Regulatory Review – Determine whether chemicals used are subject to REACH requirements or other regulatory requirements, including [9]:
  - Ensure registration requirements under REACH are fulfilled (where relevant) and that operations that will take place at the facility are covered by the registration or "downstream user report". Even if chemicals are REACH registered, additional information may be needed for notification to the Regulatory Authority (see HOCNF below).
  - Ensure compliance with specified risk management measures and operational conditions within REACH registrations and eSDSs where available; these may also be set out within relevant 'generic exposure scenarios' where chemical suppliers do not provide safety data sheets or specific exposure scenarios.
  - Ensure compliance with any requirements for authorisation of substances of very high concern (SVHC), and with any other restrictions under REACH.
  - Ensure that biocides used are authorised under the EU Biocides Regulation 528/2012 (EU BPR) [10] and that use at the facility follows safety instructions and any provisions stated in the biocidal product authorisation.
- Apply the OSPAR HMCS[15] [4] for use and reduction of discharges of offshore chemicals (or a process with similar level of assessment for non-OSPAR regions) incorporating the following elements [6,11-18]:
  - Provide the Regulatory Authority with data and information about the chemicals to used and discharged offshore, including details of chemical composition and environmental properties of the products (e.g. toxicity to aquatic organisms, fate and effects of component substances), and details on the chemical application and quantities used and discharged. Under OSPAR, provision of details of the chemical composition and environmental properties of the products requires preparing a submission according to the Harmonised Offshore Chemical Notification Format (HOCNF) [3] and associated guidelines, including the OSPAR Guidelines for Toxicity Testing of Substances and Preparations Used and Discharged Offshore [19]; similar formats could be used in other regions.
  - Ensure pre-screening is performed to verify, according to HOCNF information:
    - Chemical substances on the OSPAR List of Substances/Preparations Used and Discharged Offshore that are Considered to Pose Little or No Risk (PLONOR) to the Environment which do not require further review. Where appropriate, using such chemicals in place of more harmful substances is to be preferred.
    - Chemical substances having combinations of high toxicity, high potential for bioaccumulation and low degradability that are identified as requiring substitution, and the user should be asked to find suitable alternatives [20].

[15]OSPAR Agreement 2012-7 [3] states that the risk management approach developed under Recommendation 2012/5 is valid only for substances causing direct effects and does not address postponed effects that may be caused by bio accumulative and persistent substances. These should in principle not be used, as under [10] (as amended by [11]).

- Perform a Risk Assessment to determine the risks posed by chemicals of key concern. Models and parameter calculations may aid this process, e.g. the Hazard Quotient (HQ), representing the ratio between a chemicals predicted environmental concentration (PEC) - derived from exposure models, and the predicted no effect concentration (PNEC) - derived from ecotoxicity tests. PLONOR substances can usually be exempted from such an assessment. The use of models for risk assessment should assume the following:
    - Modelling will be performed for parameters resulting from discharge of effluent from a facility. This may include bioassays of effluents, and assessments of naturally occurring substances and added chemicals discharged including ecotoxicological information, substance physical and chemical properties, discharge information (volume, depth, etc.); and site-specific conditions.
    - The PEC may be predicted by use of a 1-, 2- or 3-dimensional dilution/dispersion model. It should be demonstrated that dilution is not overestimated by the model by use of (peer reviewed) field validation study(s). Furthermore, the model chosen should be well documented and its users should be trained and competent.
    - If the exposure level does not exceed the PNEC outside a column of water surrounding the facility known as the "mixing zone", the radius of which is defined by a distance from the facility, or outside the volume of water directly impacted by the discharge (as determined by hydrographic modelling of dispersion of the discharge), the risk should be considered to be adequately controlled.
    - If exposure levels could approach or exceed the PNEC value, steps to reduce the risks should be considered.

- For new facilities and modifications to existing facilities, ensure engineering design for chemical handling and storage accounts for inherent safety and minimisation of potential for environmental impact in the event of either a planned or unintended release (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Have in place a Spill Contingency Plan for the management of spills to the marine environment, which should include measures in place for chemicals (Section 3.5.13) [21].
- Implement additional approaches as considered necessary to manage risks of unintended losses of containment for specific operations to ALARP or equivalent (Section 3.5.10). Such best risk management approaches should include:
    - Chemical transfers onto the facility:
        - Ensure lifting and/or pumping procedures and risk assessments in place for all transfers onto and off the facility from supply vessels.
        - Ensure personnel competence procedures in place for personnel involved in all chemical transfer, handling and storage operations.
        - Ensure that supply vessels are certified for the transportation and storage of chemicals.
    - Storage and handling of chemicals/chemical waste on topsides/subsea:
        - Undertake a risk assessment and classification exercise to determine the class of containment required (i.e. primary, secondary and tertiary) for chemicals. Examples

of containment measures and techniques are described in EC (2016) [22] and PGS (2016) [23].

- Ensure chemical storage procedures specify that chemicals and chemical waste is stored in separate, labelled containers/drums.

- Well drilling/completions:
  - Chemical usage should be monitored and recorded such that the chemical content of any unintended release is known and may be reported to the Regulatory Authority.

The following risk management measures should be considered for the handling and storage of chemicals [24,25]:

Design

- Install non-return valves at chemical injection points to production systems.
- Ensure the design pressure of chemical injection pumps is the same as the system into which they inject.
- Provide bunded areas with adequate drainage for emptying of transportable tank containers. Locate incompatible chemicals in separate bunds. Provide possibility to securely fix transportable tank containers in the bunded area.
- Consider as part of early design the necessary system capacity for storing chemicals on site.
- Define containment barriers in relation to possible leaks, incidents and accidents.
- Ensure piping from transportable tank containers or boat loading stations to permanent storage tanks or other facilities is self-draining.
- Protect permanent piping installations and hose couplings against damage from handling operations. Ensure dropped object protection on critical structures and equipment including in tote tank areas and above pipework.
- Consider the requirement for a dedicated drain to a chemical spill tank from the chemical injection package/system.
- Supply any cryogenic liquid systems with insulated bunds that are designed to collect any leaks and prevent adverse low temperature effects on structures or other equipment.
- Design to minimise risk of spills (e.g. breakage of sacks) and facilitate collection of spills. Spills of hazardous materials that cannot be recycled should be collected for transport to shore as hazardous waste.
- Design the transfer system between transport and storage tanks to be a closed system which allows the complete draining of transfer tanks. Unique couplings should be used on transfer systems in order to reduce risk of unintentional transfer to a wrong tank.

Operations

- Prioritise the return of unused chemicals to shore and only discharge to sea in exceptional cases where approved under the relevant chemical permit (e.g. emergency situations, where containment on the facility would pose a safety risk).

- For each chemical used, maintain the amounts, trade names, major hazardous components and toxicity information both at the facility and at another location, through a centrally held "live" database (i.e. kept continually up-to-date).
- Ensure that chemical spill response and containment equipment is routinely inspected, maintained, and operationally exercised and tested, and is deployed or available as necessary for response.
- Ensure that discharges of hydraulic fluid and other chemicals used for the operation of subsea equipment are minimised, and that their magnitude and frequency of discharges is continually monitored.
- Document and report all spills, as well as near misses. Following a spill or near miss with potential for significant environmental impact, carry out a root cause investigation tailored to the specific incident, and undertake corrective actions to prevent recurrence.
- Maintain transfer equipment and storage facilities in accordance with manufacturer guidance and regulatory requirements (e.g. on frequency of maintenance) and retain records of such maintenance.
- Inspect transfer equipment and storage facilities in order to identify any potential structural flaws or leaks, as well as ensuring security of these facilities.

19.3 References for Section 19

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20. Offshore Activity 4: Energy Efficiency

20.1 Summary of the Activity and the Potential Environmental Impacts

The hydrocarbons industry is an energy-intensive industry by virtue of the activities it carries out, and hence energy efficiency and energy savings have long been essential to the industry's operations [1]. Energy consuming activities occur throughout field life including during drilling; oil and gas production (e.g. for pumping, gas lift, processing) and for the powering of utilities and auxiliary systems in various phases.

A whole of field life approach to energy management can lead to significant energy use savings and hence reduced air emissions; mitigation of noise issues associated with energy production (e.g. diesel generators); and overall operational cost reductions. This Section focuses on specific approaches and techniques for energy management leading to improved energy efficiency of a facility, over and above those typically considered as part of design, process integration, and maintenance [1-4]. It should be noted that the applicability of energy efficiency approaches and techniques is highly dependent on both operational phase and the age of the facility concerned.

Offshore, many facilities are located at a distance from land that makes their connection to onshore energy grids unviable or are mobile facilities for which a fixed shore connection would be unsuitable. Therefore, power is usually generated on the facilities. Power generation equipment (turbines, engines, etc.) is used to provide an energy source for main and auxiliary plant systems. This normally occurs via either turbines or large reciprocating diesel engines. Turbines may run on diesel or gas and may utilise produced gas from the separation process [1,2]. Where there is an insufficient amount of associated gas to fuel the power plant, crude oil may be used as fuel for power generation if suitable generators are available [3]. Imported gas or diesel can also be used in this situation.

Energy requirements offshore vary according the stage of particular operations being carried out. Drilling facilities, for example, require energy to support drilling activities, often over extended periods of time. Producing facilities with a long-expected field life may experience a gradual increase in energy needs as production levels decline, and measures employed to enhance production such as water and gas injection, gas compression, and reinjection of produced water increase. In addition, likely increases in volumes of produced water may require increased energy input.

The key environmental issue of concern as regards energy management is ensuring the effective use of energy and the minimisation of air pollutant emissions. Emissions to air from power generation are not in the scope of this Guidance Document but are rather covered by the IED LCP BREF [5] under Directive 2010/75/EU on industrial emissions. As well as mitigating risk to the environment, energy management offshore ensures the operational efficiency of the facility overall. It is also in the interests of organisations involved in offshore activities to carefully manage energy from an economic perspective.

Measures can be applied during all field operations phases to ensure appropriate energy management, with the greatest opportunity to influence energy efficiency of an offshore facility occurring during the design phase. A well-structured energy management system is expected in order to meet minimum requirements of Article 8 of the Energy Efficiency Directive (2012/27/EU) (Annex VI) [6]. Significant energy use savings can reduce emissions to air and enable infrastructure and other cost reductions. Indeed, one of the documents that hydrocarbons organisations typically produce during the design phase is a BAT Review for power generation, which examines different candidate power generation solutions and reviews these in the context of the facility design as a whole. BAT Review typically includes an option selection process resulting in the identification of an optimal solution. It is not described in further detail here owing to its inclusion within the IED LCP BREF [5].

Risks directly or indirectly linked to energy efficiency such as the impact of flaring or gas venting, atmospheric emissions and resource minimisation are normally included as part of an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7) and are addressed in Offshore Activity 5 (Section 21).

20.2 Best Risk Management Approaches

The best risk management approaches for improving the energy efficiency of projects/facilities are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels (Section 3.4.2).
- Consider energy efficiency requirements as part of the earliest possible stage of the approval process for all capital investment projects.
- Ensure that energy management is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- Implement an Energy Efficiency Management System, either as a stand-alone system [7] or as part of an integrated management system [8], covering the entire life of field operations and including the following elements [9]:
  - Definition of an Energy Efficiency Policy for the facility, and commitment of senior executives to that Policy.
  - A system framework that includes a strategy with objectives and targets, and a set of operational procedures to support achieving that strategy.
  - A basis for the adopted energy efficiency strategy, including a risk assessment that reviews health, safety, societal, security and environmental risks related to energy consumption to understand trade-offs that may be achieved while managing risk to tolerable levels.
  - Mechanisms and tools for forecasting energy consumption over the lifetime of the project, taking into account anticipated variations, e.g. expected changes in production profile for producing installations [6].
  - Benchmarking, including the identification and assessment of energy efficiency indicators (e.g. operational processes, supply chain, etc. [10]) over time, and the systematic and regular comparison with sector, national or regional norms for energy efficiency.
  - Performance review and corrective action functions, including:
    - Perform efficiency monitoring including energy metering and monitoring programmes, adequately implemented, to allow an energy consumption baseline to be defined.
    - Review against manufacturers' specifications.
    - Conduct analysis of energy consumption and efficiency and identify practical and cost-effective ways in which energy efficiency can be improved.
    - Ensure ongoing effective maintenance of infrastructure, particularly energy intensive equipment, e.g. compressors and pumps.
    - Conduct periodic energy audits.
  - Review of the Energy Efficiency Management System by senior management to ensure its continuing suitability, adequacy and effectiveness.

- For new facilities and modifications to existing facilities, ensure engineering design (Section 3.5.5) accounts for energy efficiency aspects including:
  - For new facilities, apply integrated design practices that consider the facility as a single system and aim to minimise overall energy use across the expected range of operating conditions while maximising production, configuration choices, and treating options.
  - For existing facilities, although fewer opportunities to improve energy efficiency may be available, it is still possible to increase efficiency savings by applying measures targeting energy intensive activities.

20.3 Best Available Techniques

The following techniques are considered BAT for improving energy efficiency[16]:

- Energy efficiency studies – Energy efficiency studies should be performed as part of Concept phase and during options selection processes, including quantification and valorisation of the impact of different options on the various forms of energy (extracted oil and gas, purchased gas and power, energy losses etc.). Later in the engineering design phase, energy efficiency can be further improved through the optimisation of process parameters, and careful selection of systems and equipment [9].
- Energy monitoring - Monitoring systems should be implemented widely where practicable in order to collect data, enrich data through appropriate modelling and to provide trends over time to highlight deviations or potential opportunities for energy performance improvement. Monitoring is already widely used by the hydrocarbons industry, and makes use of modern sensors, data collection and information management systems, as well as sophisticated control and analysis software.
- Reservoir management - A strategy for optimum hydrocarbon recovery should be defined during the early design phase, after which the selection of the associated development scheme and needs (artificial lift, pressure support, electric submersible pumps, gas compression, and EOR) may be determined through a strategy to optimise energy use in conjunction with other operational requirements. During operations, reservoir behaviour should be monitored, and the data compared with expectations in order to adjust the power scheme accordingly.
- Active control and enhanced monitoring of wells - In addition to reservoir management, the ongoing control and enhanced monitoring of wells contribute to improving production performance, by more rapidly diagnosing and controlling any problematic well behaviour, such as gas lift shortage (single or dual gas lift), surge and flow irregularities as they occur.
- Process systems - For offshore production, energy requirements for various systems should be considered depending on project needs. A summary of BAT for a number of specific systems is provided in Table 20.1. Design and operational principles include:
  - Compressor type and configuration (including number of trains, number of compression stages, spatial and mechanical configuration, and compressor type) should be optimised for each project. Turbomachinery (i.e. compressors, turbines, pumps) selection should account for variable production profiles where practicable.

[16] Note that these should be addressed by the Energy Efficiency Management System outlined in Section 10.2.

- Oil and gas export system design should be carefully considered in order to meet upstream equipment capacities and process performance requirements. Designing for over-capacity should be considered in terms of both initial energy requirements and efficiency and future needs throughout the life of the field.
- Hydrocarbons export needs over the field life should be reviewed to arrive at an appropriate configuration and installation of export pumps, ensuring that optimal efficiencies are achieved for different operating modes.
- Variable speed drives (VSDs) offer flexibility during the life of field operations when process variations occur (flow rate, pressure, fluid composition, etc.) or when production volumes or conditions are expected to change over time, leading to energy savings and economic benefits.
- Glycol system used for gas dehydration should be considered from the perspective of energy requirements and then dehydration performance optimised appropriately in terms of reboiler temperature, glycol recirculation rate, glycol purity, rich gas pressure and temperature before drying glycol, fuel gas stripping rate, etc.
- Waste heat recovery units (WHRUs) may be fitted on turbine stacks to deliver energy and fuel gas savings by recovering heat for use by other systems (e.g. oil/water separation).

- Water injection systems - For offshore production, the following should be considered depending on specific project requirements:
  - Injection pump configuration (including number of pumps, spatial configuration) should be optimised for each project, taking into account energy efficiency alongside technology choices, operating conditions and investment and operating costs (energy use).
  - VSDs – refer to above. For major dynamic machines (e.g. water injection pumps) and when applicable, VSD can lead to energy savings and economic benefits by avoiding discharge and suction recirculation.
- Utilities and auxiliary systems - For offshore production, the following should be considered depending on specific project requirements:
  - Cooling systems have specific energy requirements, and their configuration and performance should be reviewed and optimised according to the facility needs.
  - Heat exchangers are closed loop systems used to recover surplus heat or cooling and reuse it for process purposes (e.g. preheating, conditioning).
  - Energy efficient lighting which reduces power requirements, and assessment of lighting needs and priorities; optimisation of natural light use; selection of appropriate fixtures and energy efficient lamps (e.g. LED technology).

Table 20.1 Systems BAT Examples for Operations and Maintenance, Capital Improvements and Emerging Techniques

System	Operations and Maintenance	Capital Improvements *	Emerging Techniques **
Pumping	Focus on flow- differential pressure optimisation, minimising the number of parallel pumps in use, ensuring appropriate wearing ring clearance.	Variable frequency drives, trim or de-stage impellers to reduce head when excessive, upgrade impellers to enable fewer pumps in operation, piping and valve changes to reduce pressure drop, add expander with pump booster	

System	Operations and Maintenance	Capital Improvements *	Emerging Techniques **
		generator to recover let-down power; consider the use of electrical submersible pumps, impeller coatings and higher voltage solid state variable frequency drive modules.	
Power Generation and gas turbine drives	Favour more efficient gas turbines or grid power (where conditions permit), management of gas turbine loading to ~N+1 or possibly lower, manage air inlet filter differential pressure and maintenance, address leaking dampers around waste heat recovery units, track efficiency and degradation, optimise waster wash frequency, optimisation of energy conversion systems aligned with energy demand.	Install filters, add wind screens to deflect warm air from intakes, add inlet air chilling for summer capacity, add or upgrade to more efficient aero-derivative gas turbines or gas engines (e.g. >40% efficiency), connect to grid power, upgrade internals for higher capacity and efficiency – i.e. add compact waste heat recovery unit(s) to heat hot oil, get more power from hot gas turbine exhaust (closed-cycle gas turbine) via steam with heat recovery steam generator and condensing turbine, via hot oil and emerging techniques below Renewable energy integration. The use of renewable energy sources wherever possible depending on the power requirements, economics and local environment.	Consider the use of emerging techniques, for example, install battery trailers with ~30 minute back-up to enable N+0 operation, install renewables and battery with or without gas turbine(s), install supercritical CO_2 power generation from gas turbine exhaust with compact stack waste heat recovery unit and skid, membrane gas conditioning systems to enable low NO_x burners and or more reliable gas turbine operation).
Heat recovery and hot oil	Track process-process Overall Heat Transfer Co-efficiency and manage fouling and cleaning; maximise recovered heat before fired heat; reduce hot oil supply temperature to raise flow to users and minimise bypass; optimise pumps in operation or variable speed drive supply pressures; ensure waste heat recovery units from gas turbine exhaust is maximised and bypasses closed if hot oil furnace heat required.	Enhanced heat integration by adding area or upgrading to Welded Plate exchangers; expand waste heat recovery units to minimise overall energy use across the whole installation.	Consider the use of emerging techniques, for example, use of surplus hot oil heat in heat to power or chilling.
Air coolers	Enhanced monitoring (approach temperature, dashboards), cleaning, variable frequency drive fan optimisation, maintenance on blade pitch, belts, tip seals, hub seals.	Enhance bundles, fan blade upgrades, fan upgrades to Fibre Reinforced Plastic blades, wind screens to deflect hot air.	Consider the use of emerging techniques, for example low-fin bundles to enhance area inside tubes on air and water coolers, Whizz wheel air cooler retrofits.
Water cooling	Water quality cycles optimisation, fouling, circulating water pump and fan management.	Review cold water system packing and fans; add variable speed pumps to trim pressure, lower pressure and add small booster pump for elevated users; re-pipe large critical users in series with main header unloaded for downstream users, relocate sea water to colder inlet.	Consider the use of emerging techniques, for example novel fan designs, marine growth preventive systems for sea water fouling.
Chilling and refrigeration	Ensure optimal chiller management by assessing fouling management high chiller levels; condenser best practices; let inter-stage pressure float and use inlet guide vane or variable speed drives on	Enhance air/water cooling upstream and in condensers; re-pipe users to warmer refrigerant level; add users before economisers on 2+ stage systems; convert compressors to dry gas seals to reduce oil contamination in refrigerant.	Consider the use of emerging techniques, for example low-fin bundles to enhance area inside refrigerator condenser tubes, novel refrigerants for winter-summer optimisation.

System	Operations and Maintenance	Capital Improvements *	Emerging Techniques **
	compressor to minimise recycles; manage refrigerant quality purge light ends; revise refrigerant composition winter-summer (mainly for Re-gasified Liquefied Natural Gas cycle).		

* The feasibility of capital improvements described will depend on the outcome of a BAT assessment (refer to Appendix C).
** As these techniques are "emerging" they are included to provide context for potential future innovations and should not be considered representative of current BAT.

20.4 References for Section 20

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21. Offshore Activity 5: Flaring and Venting

21.1 Summary of the Activity and Potential Environmental Impacts

Hydrocarbons operations involve the separation and processing of reservoir fluid combinations of gas, oil and water, along with various other constituents. Systems used for this purpose incorporate flaring and venting capability to release gases to atmosphere as necessary. Flaring and venting activities may be employed as part of the [1,2]:

- Exploration phase: during oil and gas well drilling, completion and well testing operations;
- Production phase: during situations including:
  - Routine hydrocarbons production operations;
  - Planned non-routine depressurising of process equipment and pipelines for maintenance; and
  - Unintended non-routine depressurising of process equipment and pipework due to process upsets/trips or emergencies (i.e. as a safety measure).

Flaring specifically describes the situation in which gas is combusted upon its release from the process system via a flare header. Flares are typically positioned at safe distance from the operating plant and personnel to manage any risk of heat radiation and to ensure the safe dispersion of combustion products. Venting refers to the release of unburnt gas from process systems and storage. Offshore, the main sources of vented emissions are from crude cargo tanks, wastewater tanks, offloading operations, purging of atmospheric flare and vent headers, pumps and pressure controlling equipment (if gas is not flared).

Flaring and venting during the exploration phase is typically of short duration and aimed at gathering data to assist with design of production systems in later field development. Properties of the reservoir may not be well understood at this time, necessitating a requirement to release gaseous hydrocarbons to atmosphere if these are encountered during drilling, completions or well testing.

Production operations occur over longer timescales and involve putting in place more permanent plant and equipment to recover hydrocarbons, which includes flaring and venting infrastructure as part of the process design. Such infrastructure functions to enable process system depressurisation, in situations such as those outlined above. Design for production systems should hence follow a "depressurisation hierarchy" which ensures that gas arising during hydrocarbons processing is either (in order of preference):

1. Routed back into the process (e.g. for use as fuel gas or for export) negating the requirement to directly emit either carbon dioxide (from flaring) or methane (from venting); or
2. Routed to the closed flare system for combustion, resulting in the emission of carbon dioxide to atmosphere, preferable to venting which would instead result in methane emissions; or
3. Routed to atmosphere through a vent – the least preferred option from an environmental perspective, and which results in the emission of unburnt methane to atmosphere.

The decision around which of these three routes gas should take is taken based on technical, safety, regulatory, and economic constraints [3]. Given the long-term nature of production operations, changes to working practices and plant modifications can have long term, sustainable and material impacts on flare and vent emissions, and should be carefully considered at an early stage. New production facilities should be designed in accordance with the principle of "no requirement for routine operational flaring or venting".

Examples of activities which can result in venting (and potentially flaring) include all gas releases from pressurised equipment (e.g. well workovers, completions, pipeline pigging, etc.) and also hydrocarbon processing (e.g. gas dehydration process, sour gas treatment processes, etc.). Emissions from venting comprise mainly emissions of hydrocarbons, primarily methane and NMVOCs. Emissions from flaring are primarily carbon dioxide, as well as carbon monoxide, methane, VOCs, NOx, SOx, and other pollutants [1].

Flaring and venting are widely recognised as a significant source of GHG emissions and air pollution, for which risk may be managed accordingly. As outlined above, flaring is a preferred alternative to venting as it is both safer (it removes the potential for unplanned ignition of the gas) and it reduces emissions of methane which has a higher global warming potential than carbon dioxide [4]. Flaring also has the potential for impacts from light and/or noise, which may need to be considered depending on environmental sensitivities at specific locations. Emissions management as a risk management approach is discussed further in Section 3.5.14.

A detailed discussion on the use of flaring and venting as a safety measure is not included in the scope of this Section. However, this function is recognised and many of the risk management approaches and BAT that cover flaring and venting also have safety applicability. Note that under many jurisdictions, flaring and venting are permitted activities overseen by the Regulatory Authority.

Fugitive emissions are not included in this activity and are addressed as part of Offshore Activity 6 (Section 22).

21.2 Best Risk Management Approaches

The best risk management approaches for flaring and venting are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for management of flaring and venting (Section 3.4.2).
- Implement an Emissions Management Plan that covers the management of facility GHGs including methane and carbon dioxide from flaring, venting and fugitive emissions. This Plan should provide the technical, commercial and environmental justification for the management of emissions, and should take into account reservoir characteristics including composition of fluids and likely variation over time (e.g. in water, H_2S and gas-to-oil ratios). Level of detail should be consistent with facility complexity (Section 3.5.14).
- Address management of flaring and venting as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7). These may reference the Emissions Management Plan outlined above.
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Consider operating efficiency across all phases of the development from design, through exploration, production and decommissioning. Maximising operating efficiency minimises the potential for unplanned flaring events.
- When designing new facilities or making modifications to existing facilities, apply an option selection process to determine the potential for reducing flaring and venting and for recovery of gas. This may include to (Sections 3.5.5 and 3.5.14) [5]:

- Ensure gases are captured for subsequent use, and to minimise flaring and venting during exploration and production phases.
- Design new production facilities in accordance with the principle of no requirement for routine operational flaring or venting.
- Design the flare system to accommodate the range of gas flow rates and composition as predicted for the exploration/commissioning phase and, informed by actual data, for the production and ultimately decommissioning phases.
- Design to recover gas by recycling it back into the process system. For new facilities, recovery of gases is well-proven for larger emission sources/processes [6]. For existing facilities, additional recovery of waste gas may require technical modifications to processing plants e.g. installation of low-pressure compressors. It is therefore important to take account of constraints regarding the specific characteristics of the facility (type, age, space constraints) and reservoir properties. Applicability issues are addressed at the end of this Section.
- For new facilities, design flare systems handling high pressure sources to recover gas during normal operation. Recovery of gas from flare systems handling low pressure systems during normal operation should also be considered.
- Minimise venting from purges, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units and inert purge gas.
- Minimise liquid carry-over and entrainment in the gas flare stream with a suitable liquid separation system.
- Ensure that any non-hydrocarbon gases such as hydrogen sulphide or ammonia which may be directed to flare are mixed with a sufficient quantity of hydrocarbon gas to maintain complete combustion of both types of gases at the flare tip.
- Design vents such that these are routed to flare where possible.
- Provide the possibility for flare gas metering/estimation as per requirements of the EU Emissions Trading System (ETS) [7].

- Examples of specific approaches that may be implemented include:
  - Exploration (e.g. well testing):
    - Opportunities to reduce flaring should be considered during the earliest possible planning stage for well testing, particularly when the duration and intensity of tests are defined.
    - Reviews should be conducted involving representatives from multiple functions to optimise planning for well testing. Opportunities to minimise flaring once a well testing programme has started are likely to be much more limited.
    - Oil flaring should be minimised by use of temporary storage wherever possible and practicable. It should be recognised that separating oil gas and water can prove difficult on some exploration well tests and such difficulties might not be known until the well is tested.
    - Flaring from well testing should be eliminated where feasible. This will not always be possible and therefore the duration and intensity of the well test should be justified based on technical, financial and environmental basis.

- For new developments operators should be encouraged to consider in project design concepts whereby conventional well testing may be avoided entirely.

- Production operations:
  - Flaring from production operations should be eliminated where feasible. This will not always be possible and therefore the duration and intensity of the well test should be justified based on technical, financial and environmental basis;
  - Minimise flaring and venting from the point of view of both environmental reasons and for the purposes of optimising resource efficiency (avoiding the waste of finite resource and the associated revenues).
  - Allowable flaring and venting levels should take into consideration factors such as the availability of export infrastructure, design and technology options. The options to manage flaring and venting may be significantly affected by the potential for use of gas streams. These include pipeline capacity, oil and gas terminal capacity, storage and end consumers including refineries and other users of the gas streams.
  - Flaring targets (e.g. for commissioning and operation/production) should try to achieve continuous improvements in performance and should specify conditions/arrangements for any deviation (e.g. a possible increase in the target might be justified, for example, to implement a maintenance intervention which sustainably reduces flaring).

- Applicability of gas recovery to drilling and production facilities may be limited offshore, since the design may not be equipped to handle recovered gas and space limitations may prohibit retrofitting of systems. There are also a number of other limitations that should be taken into account, including:
  - For nitrogen-purged systems, recycling of gas and nitrogen mixtures contaminated with oxygen may not be feasible.
  - The nature of the gas/fluids which will arrive onto the facility during a well test or well clean-up operation is often uncertain.
  - Recovery of gas may require more energy and create more emissions than are saved through flaring and venting, and therefore careful consideration should be given to the benefits of implementing such techniques.

21.3 Best Available Techniques

The following techniques are considered BAT for flaring and venting [5,6,8,910,11]:

21.3.1 Flaring

- Implement source gas reduction measures to the maximum extent possible, including ensuring that hydrocarbon processing plant and/or equipment is designed for optimal efficiency and reliability.
- Minimise venting of hydrocarbons from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units and inert purge gas.
- Provide auxiliary power to prevent trips to flare.

- Consider either "continuously lit pilots" and "ignition-on-demand" as the primary ignition system. These can eliminate or at least minimise delay in achieving an ignited flare; and reliability of the ignition system [12].
- For new facilities or when making modifications to existing facilities, specify efficient flare tips, taking into account: combustion efficiency, optimised size and number of burning nozzles, and variability of flaring rates and gas composition [12]; and optimise the flare design according to process conditions over the expected field life.
- Specify a reliable flare pilot ignition system including an adequate supply of pilot gas with a sufficiently high calorific value, a pilot flame detection system and wind guards.
- Use flares with windshields on pilot burners as well as on the main burner, to improve combustion efficiency by deferring sidewind impacts and reducing disturbance due to light from flare.
- Perform flare monitoring to detect and address conditions that indicate inefficient combustion such as flame lift off, flame lick or visible black smoke.
- Regularly analyse gas sent to flaring and associated parameters of combustion (e.g. flow gas mixture and heat content, ratio of assistance, velocity, purge gas flow rate, pollutant emissions).
- Perform flare inspection, maintenance and replacement programmes to ensure continued flare efficiency.
- In addition, consider implementing flare noise avoidance measures including:
  - Installing injectors in a way that allows jet streams to interact and reduce mixing noise.
  - Increasing efficiency of the suppressant with better and more responsive forms of control.

21.3.2 Venting

- Design to route low pressure atmospheric vents (for example from glycol dehydrators) to flare gas recovery, or where this is not feasible to flare.
- Use an inert gas (e.g. nitrogen) as a stripping and flotation gas in dissolved gas flotation systems used for treating waste water; as a secondary seal gas in mechanical compressor seals; and as a purge or blanket gas in storage tanks (e.g. crude oil storage tanks or medium expansion tanks).
- Use hydrocarbon gas for Floating Production, Storage and Offloading (FPSO) storage tanks/blanketing that can be recovered instead of vented.

Additional guidance in this area includes [14-22].

21.4 References for Section 21

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22. Offshore Activity 6: Management of Fugitive Emissions

22.1 Summary of the Activity and Potential Environmental Impacts

Fugitive emissions are emissions that arise from plant and equipment used during hydrocarbon exploration and production operations [1]. They include emissions from leaking equipment; pipes and tubing; valves; flanges and other connections; packings; open-ended lines; pump seals; compressor seals; pressure relief valves; and from hydrocarbon loading and unloading operations [2]. Fugitive emissions may be considered as a subset of diffuse emissions, a category which also includes point-source emissions and venting.

Fugitive emissions typically include releases of hydrocarbon gas such as methane and non-methane volatile organic compounds (NMVOC). They do not include hydrocarbons released through combustion processes or process vents. Fugitive emissions are widely recognised as a source of GHGs and air pollution, for which risks must be managed accordingly. Methane is a primary constituent of produced gas and a GHG with global warming potential over 20 times that of carbon dioxide [3]. Emissions management as a risk management approach is discussed further in Section 3.5.14. While NMVOC emissions are less critical from a GHG perspective, their reduction is important for improving facility air quality, for the sake of personnel health.

Causes of fugitive emissions include improperly fitted connection points or deteriorating seals; and the changes in pressure, temperature, or mechanical stresses that lead to this component and/or equipment degradation. Methods for controlling and reducing fugitive emissions should be considered and implemented in the design and operation of facilities. Fugitive emissions should also receive significant focus from a maintenance and integrity perspective as they are a leading process safety indicator [2]. Proposed measures to avoid and reduce fugitive emissions should be considered in the context of the type of operation, facility and location concerned. Offshore, the avoidance of gaseous emissions is paramount from a safety perspective due to the proximity of potential ignition sources.

Flaring and venting on offshore facilities are addressed in Offshore Activity 5 (Section 21).

22.2 Best Risk Management Approaches

The best risk management approaches for fugitive emissions are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for managing fugitive emissions (Section 3.4.2).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).
- Implement an Emissions Management Plan that covers the management of facility GHGs including methane and carbon dioxide from flaring, venting and fugitive emissions (Section 3.5.14). This Plan should provide the technical, commercial and environmental justification for the management of emissions, and should take into account reservoir characteristics including composition of fluids and likely variation over time. Level of detail should be consistent with facility complexity. The Emissions Management Plan may include Hydrocarbon Release Management Procedure(s) (or equivalent) [4-13].

- Hold an inventory of existing and potential fugitive emission sources, and estimate fugitive emissions from these, based on consistent theoretical methodologies (i.e. repeatable calculation methodologies, estimation techniques and emission factors). The calculation of fugitive emissions where direct monitoring results are not available involves the use of an activity factor (e.g. fuel consumption or flow to flare/vent), the number of components in hydrocarbon service, and an emission factor for each source and emission gas. Where calculations are performed during design, these should be revised once in operation, and facility-specific factors used in place of default design factors. Guidance in this area includes [14,15,16,17,18].
- Fugitive emissions should be addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7), which may be cross referenced to the Emissions Management Plan outlined above.
- When designing new facilities or making modifications to existing facilities, ensure engineering design accounts for inherent safety and the minimisation of potential for environmental impact of fugitive emissions (Section 3.5.5) [19] (see BAT below).
- Implement LDAR for monitoring fugitive emissions during operations, with leak screening techniques and/or direct measurement, which may include periodic facility inspections using detection equipment, flange management, etc. [11,20-24] (see BAT below). Requires an up to date equipment register so that leaks can be logged and repaired.
- For floating facilities carrying crude oil, produce an approved and effectively implemented ship-specific VOC Management Plan covering at least the points given in [26-28], to ensure that the operation prevents or minimises VOC emissions to the extent possible.

22.3 Best Available Techniques

The following techniques are considered BAT for the management of fugitive emissions:

22.3.1 Design

- Limit the number of potential emission sources.
- Maximise inherent process containment features.
- Minimise use of flanges and other potential leak paths.
- Select high integrity equipment including valves, flanges, packings, seals and equivalent fugitive sources, to minimise leakage to the external environment.
- Consider welded piping for high and low-pressure lines containing hydrocarbon inventory.
- Specify valves with double packing seals.
- Preference for zero bleed pneumatic controllers over hydrocarbon gas-driven controllers.
- Use magnetically driven pumps/compressors/agitators) where practicable.
- Use pumps/compressors/agitators fitted with mechanical seals instead of packing.
- Specify high-integrity gaskets (such as spiral wound, ring joints) for critical applications.
- Where practical, facilitate monitoring and maintenance activities by providing ease of access to potentially leaking components.

- Select appropriate centrifugal compressor seals - Seals on the shafts of centrifugal compressors designed to prevent gas from escaping the compressor casing. These may use oil (wet seals) or mechanical seals (dry seals). Wet seals result in gas being entrained in the oil and then released when the oil leaves the compressor, resulting in a constant fugitive emission during compressor operation. Although dry seals do not use oil, some fugitive emission is still associated with gas escaping around the rotating compressor shaft, which is considered unavoidable and is also present in wet seals.
- Ensure appropriate fixed fire and gas (F&G) detection systems are specified, to detect larger volume emissions.

22.3.2 Operations

- Sniffing method – Undertake leak detection using hand-held personal analysers, to identify leaking components by measuring the concentration of hydrocarbon vapours in the immediate vicinity of the leak with a flame ionisation detector (FID), a semi-conductive detector or a PID (photo ionisation detector). The selection of the most suitable type of detector depends on the nature of the substance to be detected (e.g. [23-28]).
- Optical gas imaging (OGI) method – Undertake leak detection using hand-held cameras that can visualise the release of gas using spectroscopic techniques (e.g. [29]). Ongoing developments in the field may eventually lead to OGI being able to provide quantified emissions measurements. OGI cameras are used as part of routine processes and provide a useful means of identifying the presence of small volume leaks and seeps, especially in otherwise inaccessible facility areas. User training and competency maintenance are essential.
- Assurance and verification – Ensure that the breaking and re-making of flanged joints, including leak testing, is adequately covered by maintenance procedures as part of the facility planned maintenance system (Section 3.5.11).
- Real time methane detection – A range of quantification techniques are currently emerging which may in the future offer the opportunity to quantify emissions from a facility at a broad scale. These include solar occultation flux (SOF) or differential absorption LiDAR (DIAL) campaigns. They are included to provide context for future developments only and should not be considered representative of current BAT.

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23. Offshore Activity 7: Produced Water Handling and Management

23.1 Summary of the Activity and Potential Environmental Impacts

Produced water arises from hydrocarbon production and includes formation water from the reservoir brought to the surface along with hydrocarbons, as well as condensation water and re-produced injection water. Constituents of produced water therefore originate from two main sources: the reservoir itself; and from chemicals used at the facility during production. Together these may include [1]:

- Liquid and/or gaseous hydrocarbons and other organic substances – From the reservoir and present in crude oil and natural gas condensate (e.g. BTEX (benzene, toluene, ethylbenzene and xylene), phenanthrene, naphthalene, ethyl benzene and phenol), or used in exploration operations (e.g. drilling, completions) and production processes. These may be dispersed or dissolved in the water or free floating on the surface of water.
- Production chemicals, including for example corrosion inhibitors, scale inhibitors, demulsifiers, biocides and dehydration chemicals – Further details of chemicals used offshore are provided in Section 19.1.
- Heavy metals, NORM and other inorganics – Naturally occurring radioactivity materials and heavy metals, low levels of which may be present in the produced water stream, e.g. uranium, thorium, radium, radon-gas, lead, arsenic, cadmium, chromium, copper, cyanide, mercury, nickel, silver, zinc, vanadium, antimony, and barium [2]. Sulphides may also be present.
- Salts – measured as salinity, total dissolved solids, or electrical conductivity.
- Produced water may also have a high temperature by nature of its long residence time in subsurface geological formations, depending on reservoir characteristics including depth.

Produced water is typically the largest effluent by-product by volume from hydrocarbons operations, which can have impacts if discharged to the environment. The type and location of reservoirs has a significant influence on the volume and composition of produced water, as well as the chemicals used and hence present in produced water [3].

Produced water quantities typically increase over time as the reservoir is depleted during production. In terms of its management, produced water is typically either reinjected into a formation for production purposes, injected into a dedicated disposal well, or treated and discharged to the environment. Choosing among these alternatives should take into account energy use, required chemicals, produced water volumes and costs. Although produced water injection is preferred to water treatment and discharge, such disposal necessitates suitable injection wells and formations being available, which is frequently not the case. Such information should, however, be considered by the Regulatory Authority prior to the project approvals stage.

Produced water treatment and discharge to the marine environment is considered the least preferred option from an environmental perspective, to be applied only in the absence of other credible alternatives, and where the discharge meets environmental regulatory and quality standards. In order to meet such standards, treatment using a variety of technologies is required to reduce the dispersed oil content. The effectiveness of such technologies is dependent on its properties, such as droplet size [1].

Within the established offshore hydrocarbon industry environment of the North East Atlantic, OSPAR [4] sets the goal that, for produced water, organisations "*should ensure that plans to construct new offshore installations, or to modify substantially existing offshore installations, should take as a point of departure the*

minimisation of discharges and, where appropriate, the achievement of zero discharges of oil in produced water into the sea".

This Section covers handling and planned discharges of produced water. Accidental releases of produced water, for example due to failure of equipment or human error, may include loss of containment from storage tanks, or accidental release of untreated produced water from tanks and/or pipework/pipelines. Loss of containment of produced water more correctly represents a chemical and hydrocarbon release, and is hence considered as part of Activities 2 (Section 18) and 3 (Section 19).

23.2 Best Risk Management Approaches

The best risk management approaches for the handling and management of produced water are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for produced water management (Section 3.4.2).
- Ensure that the management of produced water during offshore operations is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- For new facilities and modifications to existing facilities, ensure engineering design (Section 3.5.5) includes an option selection process to determine the potential for produced water reduction, reuse, reinjection, and/or treatment and discharge (see description of BAT below).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Implement a management plan for produced water including the following elements [2]:
  - Identification, analysis, regular measurement, and recording of produced water flows.
  - Definition and regular review of performance targets, which are adjusted to account for changes in major factors affecting produced water (e.g. production rate).
  - Selection of production chemicals taking into account their volume, toxicity, persistence, biodegradation, bioavailability, and bioaccumulation potential (refer to information on the Harmonised Mandatory Control Scheme (HMCS) below).
  - Analysis and ecotoxicity tests to update environmental risk calculations (PEC/PNEC risk characterisation).
  - Regular comparison of produced water flows and hydrocarbon concentrations with performance targets to identify where action should be taken to reduce produced water and associated environmental impacts.
  - A strategy to ensure that possible reinjection of produced water or disposal by injection is maximised.
  - Avoiding excessive produced water through production optimisation in accordance with performance targets and BAT.
  - A Discharge plan that considers points of discharge, rate of discharge, chemical use and dispersion, and environmental risk.

- Where treatment and discharge of produced water to the marine environment is the chosen option, ensure a risk-based approach is implemented together with chemical management, for example as part of the HMCS[17]. This approach should identify the main risks and components of concern in produced water, and develop mitigating measures for these, as outlined in Offshore Activity 3 (Section 19). One example of a management tool for making such risk assessments is by application of models, e.g. Environmental Impact Factor (EIF) [8], which may be supported by proprietary software for performing risk calculations. When selecting techniques to reduce hydrocarbon content in produced water to comply with EPLs for discharge (see BAT below), apply a risk-based approach to considering the trade-off between desired OIW concentration and the inputs (e.g. energy, chemicals for treatment), the potential impacts (e.g. air emissions, chemical discharge) and the associated costs needed to achieve that concentration.;
- Monitor to verify the effectiveness of risk management measures adopted for produced water management, which may include system monitoring, effluent monitoring, and field monitoring. This should be performed on a periodic basis, or when significant facility changes occur. It should include definition and continual review of performance targets adjusted to account for changes in major factors affecting produced water (e.g. production rate).
- Implement approaches to manage unintended losses of containment of produced water, which should be considered as a release of hydrocarbons and chemicals as detailed in Offshore Activities 2 (Section 18) and 3 (Section 19).
- Manage produced water during operations using one of the following approaches, which may be considered in a hierarchy (refer to BAT below), as follows [9-17]:
    1. Minimise and use/reuse produced water where practicable during operations (e.g. re-injection during production for pressure support).
    2. Reinject produced water during production as appropriate or inject into a dedicated disposal well.
    3. Return produced water to shore for reuse or disposal following treatment where practicable.
    4. Treat produced water to reduce constituents with potential environmental impacts below acceptable EPLs prior to discharge.

23.3 Best Available Techniques

The following techniques are considered BAT for produced water handling and management in line with the hierarchy of options addressed in Section 21.2 above:

- Minimise and use/reuse produced water where practicable during operations:
    - Optimise well management during well completion activities and subsequent hydrocarbon production operations to minimise produced water.

[17]OSPAR Agreement 2012-7 [6] states that the risk management approach developed under Recommendation 2012/5 is valid only for substances causing direct effects and does not address postponed effects that may be caused by bio-accumulative and persistent substances. These should in principle not be used, as under [10] (as amended by [11]).

- Consider performing recompletion of high water-producing wells to minimise produced water.
- Use downhole fluid separation techniques, where possible, and water shutoff techniques, when technically and economically feasible.
- Use/reuse produced water, whenever possible, typically with some level of treatment, for example for reservoir pressure maintenance (EOR), or for use/reuse by third parties. Requires ensuring that any potentially harmful constituents (e.g. NORM) are not discharged to the receiving environment [5,6,7,18].

- Reinject produced water during production as appropriate or inject into a dedicated disposal well [19,20]:
  - Inject produced water into the producing formation, for example to enhance hydrocarbon recovery. Treatment to reduce contaminants may first be necessary. Applicability may be restricted in cases where the reservoir integrity would be compromised by re-injection of produced water (e.g. due to degradation of reservoir performance or souring of reservoir fluid).
  - For final disposal, consider converting former production wells into injection wells first, to minimise both geological risks associated with disposal into another formation (e.g. leakage of the disposed water to the seabed or shallow confined aquifers) and the construction costs of dedicated disposal wells.
  - For final disposal, inject produced water into another formation. May involve transportation of produced water to the injection well. Ensure that the well is in a suitable formation and that the injection well can be sealed to prevent contamination of the environment.
- Treat produced water to reduce constituents with potential for environmental impact to below acceptable EPLs:
  - Prevent prior formation of stabilised emulsions in produced water, which are typically the most difficult to treat with produced water technologies. Formation prevention can be reduced through selection of production chemicals and optimisation of chemical dosage.
  - Consider technology to prevent shearing of oil droplets during treatment, such as low shear valves and low shear pumps, since larger oil droplets are easier to separate.
  - Treatment using primary and/or secondary treatment techniques, which will depend on the properties of the oil/water mixture, and location-specific factors. Note that technologies may not be suitable for all offshore applications due to weight requirements and space restrictions. The treatment techniques available include, for example [12,21,22][18]:
    - Gravity separators – Gravity separators remove dispersed components by relying on the density difference between water and hydrocarbon phases. Gravity separator designs include: three-phase separators; and plate separators (e.g. titled, parallel, corrugated). Gravity separator are typically used at the first stage of treatment, after which oil skimming, plate interceptors, and degassing (skimming) occurs to enable removal of dispersed OIW.

[18] The typical stages of gravity separation, hydrocyclones and degassing will not be sufficient to meet the EPLs stated in the table, necessitating additional treatment steps prior to discharge.

- Hydrocyclones – Hydrocyclones are generally more effective than gravity separation as a means of separating oil droplets from water and removing dispersed oil, but they do not remove dissolved components. Hydrocyclones feed the water/oil into a tube inducing a vortex, forcing denser water to the outer wall and allowing oil to form a low-pressure phase in the centre of the tube that flows out of the hydrocyclone in the reverse direction. Hydrocyclones require a drop-in pressure and may necessitate the installation of pumps. They may be followed by a degassing vessel or gas flotation unit. Multicyclones are units containing a number of hydrocyclone stages. Hydrocyclones are considered to be able to reduce dispersed oil by up to 98 % for oil droplets > 15-30 µm and to 40-60 mg/l [21].
- Degasser (Skimmer) - Increased efficiency of oil separation may be achieved with the addition of oil skimming facilities. A Degasser (Skimmer) is sometimes found in a secondary stage of a produced water treatment system. It is a gravity separator with the aim of reducing the dissolved gas, free oil content in a produced water stream before it is re-injected or discharged. A thin layer of oil is formed and skimmed. Removal of free gas at atmospheric conditions is important for discharged water to ensure that dissolved hydrocarbon gases are released in a controlled way.
- Centrifuges – Centrifuges mechanically separate discrete liquid phases of differing densities by accelerating the material in a centrifugal field. As with hydrocyclones the heavier water phase migrates to the outer edge of the centrifuge leaving less dense hydrocarbons in the centre. Unlike hydrocyclones, which have no moving parts, centrifuges require rotating equipment, which increases complexity. Centrifuges allow for separation of smaller oil droplets than a hydrocyclone; however, energy consumption is higher.
- Gas flotation – Gas floatation removes oil droplets from water by attachment to rising bubbles. These rise to the surface of the water and may be removed by skimming. Gas flotation is usually the polishing step in a multiple step procedure to remove dispersed oil with treatment prior to this stage to reduce OIW concentration. Gas flotation units may be categorised as:
    - Induced Gas Flotation (IGF) – Flotation gas bubbles are hydraulically or mechanically generated. The horizontal multi-stage IGF units have typically four active flotation cells. The operation of a hydraulically induced gas flotation cell is similar to the mechanically induced gas flotation cell. However, instead of using a mechanically driven impeller to generate bubbles, a recirculated stream of clean water is mixed with gas and the mixture is injected into the flotation unit.
    - Dissolved Gas Flotation (DGF) – Dissolved gas in the process stream is used to generate the gas bubbles used in floatation.
    - Vertical IGF – In its simplest form, IGF is a single cell of a horizontal multi-stage IGF configuration. Vertical IGF technology incorporates between 30 seconds and 4 minutes residence time. Single stage vertical flotation units may not be as efficient for de-oiling produced water as multi cell horizontal flotation units, but vertical flotation works well in applications where horizontal flotation may not be feasible due to space and weight constraints. In the industry vertical IGF's are also referred to as Compact Flotation Units (CFUs), which is reflected in the product names of the technologies marketed by various suppliers. A typical configuration in which water is first treated in hydrocyclones, with a CFU located

downstream of either these or the degassing tank, CFU has been known to reduce dispersed oil to 10-15 mg/l (oil droplet size < 5 µm) and less than 5 mg/l in some cases.

- Membrane technology – Such technology is also referred to as micro-, ultra- or nano-filtration or reverse osmosis depending on the size of the contaminants requiring removal (larger to smaller respectively). Ultrafiltration is capable of removing dispersed hydrocarbons (including emulsions) while nanofiltration might additionally remove some larger dissolved hydrocarbons. As the energy consumption of this technique is high, this should be considered when deciding on its application.
- Macro Porous Polymer Extraction System (MPPE) is a fluid extraction technology that removes dissolved organics from produced water. Produced water passes through a column packed with porous polymer beads containing an extraction liquid that removes dissolved oil and organics. Periodic stripping of hydrocarbons from the extraction liquid is then performed. MPPE has a good track record for reducing organic constituents to low levels, including >99% removal of BTEX and PAHs, and >95% removal of aliphatics of chain lengths <C20. Removals have been less effective for aliphatics of chain lengths >C20.

- Discharge produced water after treatment, and only in compliance with national legislation and/or permit conditions [1,2,9-12,22]:
  - Determine treatment chemicals intended for use and their quantities, together with the amounts expected to be discharged and achievement of EPLs (refer to Table 23.1). Perform a risk assessment for the environmental effect of the discharges of chemicals into the sea (refer to Section 23.2).
  - Provide sampling points immediately after the last item of the produced water treatment equipment in or downstream of a turbulent region and before any subsequent dilution. A monitoring program, preferably using online OIW analysers and/or manual sampling, is recommended as BAT for monitoring the performance of the produced water treatment technologies, and monitoring the produced water quality to be discharged.
  - Return of produced water to shore for treatment [10] is only likely to be a credible option for low volumes of produced water and is unlikely to be practicable in the long term if there are increasing produced water volumes. In the event that this occurs, refer to guidance provided for Onshore Activity 12 (Section 15).

Table 23.1 EPLs Associated with the Application of BAT for the Management of Produced Water Discharges Containing Hydrocarbons [3,23,24]

New facilities EPL	Existing facilities (monthly average) EPL
Zero discharge* of oil in produced water or, where not appropriate**, minimisation of discharges as defined for existing facilities	Minimisation of discharges to < 15 mg/L dispersed oil or, where not appropriate** < 30 mg/L (per analytical method set out in [25].

* The goal of zero discharge is achievable in cases where reinjection/injection is undertaken for produced water management.

**Appropriateness of minimisation/cessation of discharges to be determined by a field specific BAT assessment, which is an assessment of existing technologies and the appropriateness of installing these on a specific platform (updated every 5 years). This will include

considerations of weight and space, safety, cost, chemical use, other emissions (e.g. air) and the assessment of the environmental risk of discharge and the main contributing constituents to that risk. Setting requirements to document this process assures that the data needed to evaluate the appropriateness of minimisation/cessation of discharges (outlined above) would be readily available. An overview of BAT assessment is presented in Appendix C.

23.4 References for Section 23

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[4] OSPAR Recommendation 2001/1 for the management of Produced Water on Offshore Installations and 2006/4 and 2011/8 amendments.

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[7] Hylland, K. and Øistein Eriksen, D. 2013. Naturally occurring radioactive material (NORM) in North Sea Produced Water: Environmental Consequences.

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[10] OSPAR Agreement 2012-7 "OSPAR Guidelines in support of Recommendation 2012/5 for a Risk-based Approach to the Management of Produced Water Discharges from Offshore Installations" http://www.ospar.org/documents?d=32930

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[15] SINTEF Norway, DREAM – Dose-related Risk and Effects Assessment Model. https://www.sintef.no/en/software/dream/

[16] OSPAR Decision 2000/2 on a Harmonised Mandatory Control System for the Use and Reduction of the Discharge of Offshore Chemicals.

[17] OSPAR Recommendation 2006/3 on Environmental Goals for the Discharge by the Offshore Industry of Chemicals that Are, or Which Contain Substances Identified as Candidates for Substitution.

[18] IPIECA, 2014. Efficiency in water use – Guidance document for the upstream onshore oil and gas industry. http://www.ipieca.org/resources/good-practice/efficiency-in-water-use-guidance-document-for-the-upstream-onshore-oil-and-gas-industry/

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[20] OSPAR Commission, 2006, Addendum to the OSPAR Background Document Concerning Techniques for the Management of Produced Water from Offshore Installations (Publication No. 162/2002). Publication number 295.

[21] OSPAR Commission 2013, Background Document concerning Techniques for the Management of PW from Offshore Installations. Publication number 602.

[22] NEL, National Measurement System, 2018. Good Practice Guide – An Introduction to produced water management.

[23] OSPAR Decision 2005/1 amending OSPAR Decision 2000/2 on a harmonised mandatory control system for the use and reduction of the discharge of offshore chemicals. http://www.ospar.org/convention/agreements?q=decision+2000%2F2&t=&a=&s

[24] Offshore Petroleum Activities (Oil Pollution Prevention and Control) (OPPC) Regulations 2005 and Amendment (2011).

[25] OSPAR Reference Method of Analysis for the Determination of the Dispersed Oil Content in Produced Water, Agreement, 2005-1.

24. Offshore Activity 8: Management of Drain Water

24.1 Summary of the Activity and Potential Environmental Impacts

Discharge of drain water to sea can affect the marine environment due to its potential contamination with hydrocarbons and chemicals used on the facility. Containment of fluids is managed using drain systems which collect liquids from process systems, capture spillages and redirect various different water flows. These systems are required to cater for both planned discharges that are expected as part of day-to-day operations, and unintended releases that may occur as a result of an accident or incident.

This activity specifically covers planned discharges of hydrocarbons from drain systems, and unintended releases involving drain systems. Unintended releases of hydrocarbons and chemicals more broadly are not addressed here, but rather covered under Activities 2 and 3. Such releases may or may not make use of the drain system, depending on the nature of the release. Note that this activity also does not cover facility domestic effluent including grey water and sewage.

Different types of drain systems are used offshore depending on their location, service requirements and other aspects of operational context. Drain systems should be designed to ensure that releases and discharges from hazardous and non-hazardous areas on a facility are separated. To fulfil this requirement, drain systems are typically divided into at least the following systems:

- Closed Drain System – completely closed pipe network accepting controlled transfer of hydrocarbons from process equipment, e.g. draining down equipment prior to maintenance.
- Open Drain System – open vented system that collects rainwater, seawater and fire protection system (sprinklers, etc.) water, leaks, wash-down water including spilt liquids/solids from decks, spills into bunded areas and drip trays around equipment. The system may be divided into:
  - Hazardous System – collects fluids from areas classified on the facility as hazardous, e.g. hydrocarbon or chemical containing plant and equipment; and
  - Non-Hazardous System – collects fluids from areas on the facility not classified as hazardous, e.g. non-hazardous workshops, warehouses and storage areas.

In all of the above systems, design typically dictates that fluids are routed to separate dedicated tanks, from which hydrocarbons are recovered by oil-in-water (OIW) separation for transport to shore as with any other hydrocarbon-contaminated water (e.g. produced water) prior to disposal of treated water to sea. Such tanks are also specified to manage gas entrained with hydrocarbons, ensuring it is purged safely from the system.

Drains from areas not significantly contaminated with chemicals and hydrocarbons (e.g. roof of the facility accommodation) are normally routed directly to sea as they are not subject to spills of hydrocarbons or chemicals. In the event of an emergency incident requiring discharge from the fire protection system (sprinklers), higher than normal quantities of water may also necessitate setting the drainage system to overflow directly to sea. This should only occur in situations where a clear safety risk is identified.

Machinery space drainage is defined as any drainage not associated with the oil and gas production process and is covered under MARPOL Regulations [1]. It is generally relevant to offshore floating facilities, and examples of machinery space drainage include FPSO and vessel/MODU bilges, etc. [2].

In addition to the above, systems for handling operationally specific situations may arise in which other fluids are present on a facility and require management, including:

- Highly volatile chemicals requiring separate systems such as dedicated bunding and collection, e.g. methanol, and other chemicals sometimes held for use in tote tanks on offshore facilities;
- Compounds present in crude oil, e.g. H_2S, NH_3 gas require additional plant and equipment to strip these from the process stream and treat fluids before entering the closed drain system;
- Laboratory chemicals used offshore for the purposes of analysis, usually in relatively small quantities. These are typically managed within the scope of laboratory activities, with waste materials being collected and transported to shore; and
- Chemicals used for cleaning of indoor and outdoor facility areas, e.g. decks, that are washed into the drain systems.

Unlike for removal of hydrocarbons, no mechanism is in place for the treatment of chemical contamination in drain fluids prior to discharge. Instead, planned discharges of chemicals are typically permitted operations and as part of the process a risk assessment on the specific intended discharge should be conducted and submitted through a permit application to the Regulatory Authority.

Most of the approaches and techniques that can be implemented in order to ensure effectively functioning drain systems are primarily relevant to the design stage of a facility. Once a facility is operational, techniques are mainly concerned with ensuring asset integrity.

24.2 Best Risk Management Approaches

The best risk management approaches for managing contaminated drain water are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for managing drain water (Section 3.4.2).
- For new facilities and modifications to existing facilities, ensure engineering design for management of drain water accounts for inherent safety and minimisation of potential for environmental impact, in the event of either a planned or unintended release (refer to BAT below) (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Ensure that planned discharges from drainage are addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- Ensure that a Spill Contingency Plan is in place for the management of spills from the facility into the marine environment, including the response to the spill and procedures for its remediation (Section 3.5.13).

24.3 Best Available Techniques

The following techniques are considered BAT for management of drain water:

24.3.1 Design

- Ensure that the drains system functions within the environmental, technical safety and integrity design envelope of the facility (e.g. [1,3-6]).

- Ensure segregation between closed and open drains and between hazardous and non-hazardous open drains.
- Prevent hydrocarbon/chemical spillages overboard and outside designated areas and drip trays/coamings/bunds.
- Consider the location of drain and slops tanks in relation to facility process areas in line with environmental parameters, ensuring slope gradients between these is achieved.
- Fit production and utility systems with sufficient drain points to enable controlled draining of all segments in an optimal manner.
- Prevent the accumulation of hazardous liquids on facility deck areas.
- Consider larger piping diameters in the drain system including at pipe bends to allow for cleaning, in situations where the presence of sands and solids is expected.
- Provide drip trays/coamings/bunds under equipment and pipework from which spillage and leaks could occur, for example:
  - Process equipment.
  - Tote tanks (diesel, chemicals, etc).
  - Bunker stations.
  - Crude offloading equipment.
  - Workshops and maintenance areas.
- Prevent migration via the drain system of fluids, gases (and fires) between facility areas.
- Permit recovery of hydrocarbons from drained fluids, and the safe disposal of clean/treated water, e.g. from rain, fire system deluge, and drains systems effluent.
- Provide sampling points where practicable with convenient access such that the quality of water discharged to sea from drain system tanks may be monitored and recorded.

24.3.2 Operations

- Consider operational-specific factors that may compromise parameters for which drain systems were designed and undertake risk assessments (e.g. HAZID/ENVID/ HAZOP) as necessary (Section 3.5.6).
- Maintain a chemical inventory, minimising the number and variety of chemicals on the facility, limited only to those necessary for current operations, and having conducted a risk/exposure assessment for new chemicals per Regulatory Authority permitting requirements [7]. This is discussed in detail in Section 23.
- During maintenance and other activities, avoid discharges of chemicals to the drain system where practicable, collecting these in dedicated containers for transport to shore.
- Ensure inspection, repair and maintenance of drain system integrity (i.e. leak prevention) covered by a Planned Maintenance System (see also Section 3.5.11).
- Subject to risk assessment, consider providing facilities for the storage and transport to shore of off-spec contents from drain system tanks, including hazardous materials and contaminants.
- Review compatibility of different fluids used to prevent chemical reaction/solidification in the open drain system.

- Ensure offshore operators understand the different types and correct operation of the facility drain systems.
- Apply procedures and/or equipment for calculating/monitoring chemicals in offshore discharge stream, where practicable.
- Ensure that automatic flow diversion devices preferentially transfer contaminated runoff to the drains system prior to any routing overboard[19].
- Where legacy systems on existing facilities do not allow for accurate discharge sampling, set stringent internal targets and monitor inputs to minimise risk of environmental exposure.
- Ensure procedures are in place to remove chemical spills using spill kits and dispose of as hazardous waste, not washed into hazardous drains system, unless there is an overriding safety concern.

EPLs associated with the application of BAT for discharges to sea from draining of water and other liquids are presented in Table 24.1. Alternatively, other techniques can be applied that allow equivalent performance levels to be achieved.

Table 24.1 EPLs for Discharges to Sea of Hydrocarbons

Parameter	EPL
Oil in water (OIW) discharged (monthly average) [8]	30 mg/L *
Oil in water (OIW) discharged (Machinery Space drainage) [1]	15 mg/L

* Per OIW discharge EPL for produced water, refer to Offshore Activity 7.

Discharges of hydrocarbons from hazardous and non-hazardous drains may be sampled and analysed using the BEIS IR, FT-IR or GC/MS methods or different solvent systems [9]. The OSPAR Reference Method of Analysis [10] also applies. The industry recognises that, in practice, measuring a "monthly average" for drain water is likely to be a challenging endeavour, and that monitoring requirements remain at the discretion of the Regulatory Authority.

24.4 References for Section 24

[1] IMO MARPOL– International convention for the prevention of pollution from ships. Annex I - Regulations for the Prevention of Pollution by Oil.

[2] Oil & Gas UK. Drainage – Machinery Space, https://oilandgasukenvironmentallegislation.co.uk/contents/topic_files/offshore/oily_water.htm

[3] API RP 14 C, 2017. Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety systems.

[19] For unintended releases of highly volatile or flammable materials, safe routing elsewhere is preferred

[4] API RP 14J, 2001. Recommended Practice for the design and hazards analysis for Offshore Production facilities.

[5] Energy Institute, 2015. EI 15 – Model code of safe practice Part 15 – Area classification for installations handing flammable fluids.

[6] UK Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (as amended) Guidance Notes.

[7] OSPAR Decision 2000/2 on a Harmonised Mandatory Control System for the Use and Reduction of the Discharge of Offshore Chemicals (as amended by OSPAR Decision 2005/1).

[8] World Bank/IFC, 2015, EHS Guidelines for offshore oil and gas development, http://www.ifc.org/wps/wcm/connect/f3a7f38048cb251ea609b76bcf395ce1/FINAL_Jun+2015_Offshore+Oil+and+Gas_EHS+Guideline.pdf?MOD=AJPERES.

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[10] OSPAR, 2005. Reference Method of Analysis for the Determination of the Dispersed Oil Content in Produced Water, Agreement 2005-15.

25. Offshore Activity 9: Risk Management for Facility Decommissioning

25.1 Summary of the Activity and Potential Environmental Impacts

Decommissioning describes the measures taken in connection with the permanent cessation of facility operations. Although strictly speaking "decommissioning" defines the steps involved in the ending of a facility's active status, in the hydrocarbons industry it also broadly covers the subsequent management of facility infrastructure, wells and pipelines, in terms of reuse, removal or (in exceptional cases) leaving in place. Decommissioning can be broken down into the following stages:

- Plugging and abandonment of wells;
- Preparing topside structures for removal, and subsequent removal of those structures;
- For fixed facilities, dismantling and removal of structures such as jackets and those fixing the installation to the seabed;
- For floating facilities e.g. FPSO, removal from station of the vessel;
- Management of subsea infrastructure including pipeline and bundle assemblies, umbilicals, etc. where in place; and
- Shipping of used infrastructure (may occur at all stages).

Permanent well plugging and abandonment (P&A) usually occurs first, and involves the cessation of production and preparation for plugging, the actual well plugging and verification, and finally removal and recovery of the wellhead/conductor [1,2]. Maintaining well integrity during and after this process is paramount. Well plugging typically involves the use of cement plugs to prevent the leakage of hydrocarbons to the surface and/or to any other formations with flow potential. There is a high degree of reliance placed upon existing annular cement quality at the depths where plugs are to be set. Such annular cement quality should be assessed and, if necessary, remediated prior to setting the main well plugs. Following P&A, the status and locations of the abandoned wells are recorded and provided to the Regulatory Authority.

Topsides are normally removed from the field as part of decommissioning. Prior to removal, the topsides are prepared in line with environmental and safety considerations, by ensuring facilities and pipework are secured, (e.g. cleaned, drained), and that spent materials are appropriately managed to enable safe execution of subsequent activities. Any hazardous materials with potential for leakage to the environment should be removed, or secured as appropriate. Engineering studies are typically used to support selected removal methods. Topsides removal can involve the cutting of topside modules. Smaller substructures may be removed in a single lift and transported onshore, while larger substructures may require sectioning before transport. Minimising the number of lifts is favourable as it reduces time offshore and required marine traffic.

For fixed facilities, jacket decommissioning refers to removing the frame which connects the topsides to the seabed and which is fixed in place using steel and concrete materials. It is possible to remove the topside platform from the jacket and then to remove the jacket from the seabed, leaving behind the footings and remaining structures. The removal of jacket facilities may, for example, include:

- Dismantling of the jacket structure, involving the use of cutting tools;
- Cleaning the jacket to remove marine growth, for example to prepare cut zones and, in cases where infrastructure will be relocated, to avoid the translocation of marine species;

- Management of the jacket structure itself which can involve removal as one piece, cutting into sections, or further cutting into smaller components to aid the ease of removal and shipping; and
- Removal of footings, which requires uncovering these and cutting (e.g. using abrasive, diamond wire) to remove the bulk of the structure[20].

For footings which may be left in-situ, the potential risk posed by upright structures to other marine users such as fishing vessels should be considered as part of the EIA (Section 3.5.4). It would also be the decision of the Regulatory Authority as to whether leaving footings in-situ would be acceptable.

Options for structures on the seabed including pipelines, bundles, templates, manifolds, valve stations, wye pieces, etc. should be considered, including [3]:

- Leave in-situ – assuming pipeline(s) do not pose a risk to other users of the sea;
- Partial removal – removing some ancillary structures such as concrete mattresses, pipeline end manifolds; and
- Full removal – removal of pipeline(s) following a reverse process for pipe-laying which may involve a pipelay vessel retrieving the pipeline from the seabed.

Sufficient cleaning of pipeline(s) should also be considered prior to removal.

Shipping is used to remove equipment and materials for each of the processes outlined, with shipping vessel size, type and frequency of planned trips dependent on the facility and removal processes.

Decommissioning should also ensure that the following activities are carried out:

- Safe removal onshore or offshore of hazardous materials such as asbestos, polychlorinated biphenyls (PCBs), hydrocarbons, or H_2S [4]; and
- Remediation of the site, including activities to remove debris, reduce or eliminate potential impacts, and to restore environmental conditions to acceptable levels with reference to regulatory or company standards as appropriate[21].

Impacts from drill cuttings piles may arise due to the moving of previously discharged oil-based mud contaminated cuttings (although in many regions including OSPAR, cuttings discharge with BFROC >1% is no longer permitted [5]) in order to access subsea infrastructure. Hence a range of potential management options for such cuttings piles should be considered [6]. Disturbed water-based drill cuttings piles do not appear to lead to increased impacts on the marine environment and hence no specific measures are normally required for their management [5].

The entire removal of the facility from offshore locations for reuse, recycling, or final disposal on land is preferred [7], except where an organisation makes a clear case for an alternative disposal option. The decision ultimately rests with the Regulatory Authority, taking into account all relevant circumstances. Comparative assessment of alternative disposal options should consider facility type, disposal methods, disposal sites, and environmental and social impact, including interference with other sea users, impacts on safety, energy and raw material consumption, and emissions. Furthermore, where an assessment indicates that decommissioning and leaving in place is less environmentally harmful than removal to onshore then this

[20] Note that foundation structures below seabed level (e.g. pilings) are typically accepted to be left in place.

[21] See also OSPAR Recommendation 2006/5 on a Management Regime for Offshore Cuttings Piles.

may be considered [8].re-use and decommissioning-in-place are internationally recognised decommissioning methods, which may be employed if determined to be the least environmentally impactful alternatives.

Provided that decommissioning is carried out in accordance with best risk management approaches, environmental impacts of the operation itself should be relatively limited. These may include emissions/discharges associated with removal operations, e.g. discharge of chemically treated structural water and cutting material (heavy metal containing abrasive grit), discharge from pipelines during cleaning, and discharge of eroded paint from paint removal if this occurs.

25.2 Best Risk Management Approaches

The best risk management approaches for decommissioning are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for facility decommissioning. The HSEMS should contain consideration for the environmental impacts from eventual facility decommissioning at the design stage, and throughout operating life (Section 3.4.23).
- Perform a Comparative Assessment for decommissioning, comparing the potential impacts on safety, environment, stakeholders, technical feasibility and cost, in order to select the appropriate decommissioning option, and to ensure management of risks to people (e.g. personnel and other users of the sea) and the environment, in line with OSPAR 98/3 [7,8]. Where the assessment indicates that decommissioning and leaving in place is less environmentally harmful than removal to onshore then this may be considered with agreement of the Regulatory Authority [7]. Assessment may be carried out using decision support tools (e.g. multicriteria analysis) which are rational, transparent and retraceable; and allow the management of conflicting objectives.
- Produce a Decommissioning Plan, agreed with the Regulatory Authority and describing the measures the operator proposes to take in connection with the decommissioning of the facility, wells and pipelines (Section 3.5.15).
- Ensure that decommissioning is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7), which includes:
  - Offshore activities relevant to decommissioning of infrastructure, their associated environmental impacts and management measures as detailed in the Decommissioning Plan.
  - Onshore activities relevant to the reuse, recycling, recovery and disposal of disused infrastructure and associated spent materials. Although typically a third-party activity, management measures for these activities should be addressed in overview.
  - Stakeholder engagement component that takes into account the interests of other sea users. Example guidance in this area includes: [9].
- Consider the use of Comparative Assessment in engineering design when assessing options in the decommissioning/execution phase and that procedures are in place for the following operations (Section 3.5.5):
  - Well plugging and abandonment.
  - Facility decommissioning operations.
  - Drill cuttings pile management.

- Management of facility infrastructure returned to shore.

- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2). Implement a risk-based programme for post-decommissioning environmental monitoring and aftercare.

25.3 References for Section 25

[1] Oil & Gas UK, 2015. Guidelines for the abandonment of wells – Issue 5. http://oilandgasuk.co.uk/product/op105/

[2] Oil & Gas UK, 2015. Guidelines on qualification of materials for the abandonment of wells – Issue 2. http://oilandgasuk.co.uk/product/op109/

[3] OGP, 2014. Options for decommissioning subsea bundles, OGP Report No. 469.

[4] Climate and Pollution Agency Norway, 2011. Decommissioning of Offshore Installations, Report TA2761.

[5] OSPAR Commission, 2009, Assessment of the possible effects of releases of oil and chemicals from any disturbance of cuttings piles (2009 update)

[6] DNV GL, 2017. Drill cuttings piles management and environmental experiences, Report No.: 2017-4056, Rev. 01.

[7] OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations. https://www.ospar.org/convention/agreements?q=98%2F3&t=32282&a=&s.

[8] 1996 Protocol to the Convention on the Prevention of Marine Pollution By Dumping Of Wastes And Other Matter, 1972 (as amended in 2006) (the "London Protocol")

[9] Norsk Olje og Gass by DNV, 2001. Handbook for consequence evaluation in offshore decommissioning. Report 00-4041. https://www.norskoljeoggass.no/contentassets/d7bfa8b2f6874235a1e0dc0719b7250a/handbok-i-ku-ved-offshore-avvikling-dnv-2001.pdf

26. Offshore Activity 10: Environmental Monitoring

26.1 Summary of the Activity

Monitoring may be performed for any offshore hydrocarbon activities that have been identified as having potential environmental impacts. Environmental monitoring can involve direct or indirect measurement of emissions, discharges, and resource use applicable to operations and process parameters, as well as of impacts on environmental receptors.

Monitoring activities are undertaken throughout facility or project operational life, i.e. from before activities commence to establish baselines, as well as during development, production and decommissioning. Monitoring provides insight to support management and ultimately reduces impacts. Appropriate environmental monitoring and control equipment can, in some cases, allow operational improvements and assist in checking compliance with permit conditions while activities are underway.

Monitoring may include, for example:

- Collection of information and data for assessing baseline conditions (e.g. at the approval stage of a development) and for undertaking environmental assessments (e.g. during design and operations).
- Measuring and/or estimating environmental parameters and potential environmental impacts (e.g. during production), such as:
  - Emissions to air (e.g. CO, CO_2, NO_x, SO_x, CH_4, NMVOCs, PM, ozone, particulates, odour) by calculation and/or direct measurement – emissions from power generation, flares and process equipment (e.g. from acid gas removal unit (AGRU) incinerators, hot-oil furnaces, steam boilers, etc.); fugitive emissions (e.g. from compressor seals, valves, flanges and pumps); vented emissions (e.g. from storage and loading facilities); and other process emissions;
  - Discharges to the marine environment (e.g. chemicals, oil-in-water, etc.) - quantity and composition of drilling discharges; subsea completion and control fluid discharges; hydrotest water; produced water; cooling water; sewage and grey water; desalination reject water; deck drainage; ballast water;

Monitoring also occurs for unintended releases (e.g. leak detection systems and reactive monitoring). Examples of unintended discharges include an accidental spill of oil or chemicals to sea, and examples of unintended releases include a leak of gas from process equipment or a loss of containment from gas production or storage. Measures in place to prevent, detect, control, mitigate and remediate such events are discussed in further detail throughout the other activities in the Guidance Document.

This activity covers both monitoring of the source air emissions and marine discharges (for example in terms of volume, composition, location and timing of release) and monitoring of the environmental impacts from emissions and discharges (i.e. monitoring the receiving environment), both of which should be integrated and mutually reinforcing.

Monitoring parameters selected against each of the lifecycle phases should reflect the pollutants and activities of concern associated with proposed and actual operations and should address both the monitoring of emissions and discharges as well as impacts on the receiving environment. Monitoring should

be carried out with a clear overall objective, and a strategy that considers parameters including ecosystem context, location, contaminant properties, and levels of detectable change in the receiving environment.

26.2 Best Risk Management Approaches

The best risk management approaches for environmental monitoring are to:

- Have in place an organisational HSE Management System (or equivalent) that drives health, safety and environmental management at corporate and operational levels, and contains processes and procedures for environmental monitoring (Section 3.4.2).
- Ensure that environmental monitoring of emissions and discharges is addressed as part of management measures detailed in an environmental risk assessment such as an EIA/ENVID (Sections 3.5.4/3.5.7).
- Develop and implement a risk-based Environmental Monitoring Programme, covering all activities and aspects that have potential environmental impacts, and includes elements as set out in the environmental risk assessment (see above). Different offshore development phases and activities, and local environmental conditions, will dictate different survey strategies and monitoring frequencies. In general, two different approaches may be applied: field specific monitoring and wider area (regional) monitoring [1]. An Environmental Monitoring Programme should include indicative elements:
  - For each project phase:
    - Early development - Carry out baseline monitoring at and in the vicinity of the site as part of an Environmental Baseline Study in order to differentiate between existing ambient conditions and project-related impact (Section 3.5.3).
    - Design/Development - Collect additional information and data as part of EIA (Section 3.5.4). The type, frequency and duration of environmental monitoring requires a site-specific approach that would normally be set out in the EIA and may take as its basis the Environmental Baseline Study.
    - Production – Ensure that the monitoring is addressed in the production phase, during which it should become a routine activity typically included within an Environmental Management System / HSE Management System (see above) [2,3].
    - Decommissioning - Collect environmental data to establish the pre-decommissioning baseline, in a similar manner to the Environmental Baseline Study outlined above (Section 3.5.3), and undertake risk-based post-decommissioning monitoring.
  - Overarching objectives [4,5,6,7]:
    - Establish the types and quantities of substances planned as emissions and/or discharges from the facility.
    - Establish the spatial distribution and extent of emissions and discharges expected, and their impacts on the environment, supported as necessary by environmental modelling (Section 3.5.6).
    - Establish environmental baseline through initial survey (including analysis of historical data for existing assets).
    - Establish temporal trends to estimate the magnitude of environmental changes over time with respect to this baseline. Emissions from highly variable processes

may need to be sampled more frequently or through composite methods. Emissions monitoring frequency and duration may also range from continuous for some combustion process operating parameters or inputs (e.g. the quality of fuel) to less frequent, monthly, quarterly or yearly tests.

- Determine and implement required measures for monitoring identified emissions and discharges, and their associated environmental impacts.
- Undertake continual review to identify unforeseen impacts and new issues, including follow-up survey(s) to monitor environmental changes.
- Select monitoring parameters based on a risk assessment approach [6]; that considers at least the following risk factors [8]:
  - Size and type of the installation, which may determine its environmental impact.
  - Complexity of sources (i.e. number and diversity, source characteristics, e.g. area sources, channelled emissions, peak emissions).
  - Complexity of the process, which may increase the number of potential malfunctions.
  - Possible environmental and human health effects resulting from hazards taking into account their level of risk.
  - Proximity of the hazard to sensitive environmental receptors.
  - Presence of natural hazards, such as geological, hydrological, meteorological or marine factors.
  - Past performance of the installation and its management.

- Key considerations for monitoring emissions and discharges from a facility:
  - Apply standard CEN / ISO measurement techniques which are considered best practice and are recommended to ensure high quality results.
  - For air emissions, consider in the planning stages as to how data relating to fuel flow, gas turbine load parameters, gas composition data, and stack velocity are to be monitored and recorded in parallel with monitoring (direct or indirect) of emission concentrations.
  - Identify main emission and discharge sources that warrant monitoring, and the minor sources that may either not require monitoring or could be monitored less frequently or monitored using portable devices.
  - Characterise emissions profiles over a range of representative operating conditions, and for relevant fuel types (i.e. gas and/or diesel), in line with the relevant national and local legislation.
  - Have an understanding of the level of uncertainty of all monitoring equipment and methods, in percentage terms (e.g. +/-10%). This will vary depending on type of monitoring and should be accounted for when reporting emissions and discharges.
- Key considerations for monitoring environmental impacts (i.e. on receiving environment) [9]:
  - Ensure data generated through the monitoring programme is adequately representative for the processes and activities being addressed over time.

- Consider the sensitivity of the receiving environment.
- Establish monitoring locations based on the interpretation of the results of scientific methods and mathematical models, where applicable, to assess the site conditions at regular intervals, compare the results to the environmental baseline study and to measure the impacts of the activities and assess the effectiveness of mitigation measure.
- Apply national or international methods for sample collection and analysis, such as those published by CEN/ISO or others as appropriate (e.g. OSPAR). Sampling should be conducted by, or under the supervision of, appropriately experienced individuals.
- Apply sampling and analysis quality assurance / quality control (QA/QC) plans, and document to ensure that data quality is adequate for the intended data use (e.g. method detection limits are below levels of concern). Monitoring reports should include QA/QC documentation where appropriate.

- For new facilities and modifications to existing facilities, ensure engineering design accounts for inherent safety and the minimisation of potential for environmental impact by including monitoring equipment and procedures for emissions and discharges (refer to BAT below) (Section 3.5.5).
- For all facilities, ensure appropriate "HSE Documentation" is in place, a key function of which is to: present and justify the technical, management and operational measures proposed to identify and control hazards, including those that may lead to accidents and environmental incidents (Section 3.5.2).

26.3 Best Available Techniques

The following techniques are considered BAT for environmental monitoring:

26.3.1 Design

- Provide sampling ports on combustion equipment, where safe to do so, including gas turbines, emergency generator, etc. for sampling of exhaust gas, and concentrations of CO, SO_x, NO_x. Sampling ports provide the location at which portable gas detectors are inserted to monitor emissions.
- Quantify fugitive emissions in design based on the number of components in hydrocarbon service and generic emission factors, e.g. as developed by UKOOA [10]. Once in operation these should be revised, and facility-specific factors used in place of the default design factors. Refer also to Offshore Activity 6 (Section 22).
- Provide equipment for the measurement of produced water volume, both prior to either reinjection and/or discharge in different operating conditions.
- Perform OIW analysis (e.g. OIW analyser or laboratory analysis) as well as providing manual sampling points at the point of discharge, for analysing OIW concentrations in produced water and other discharges. Analysers should be installed after the last stage of treatment prior to any discharge, and before any commingling or recycle loop. OIW manual sampling points should be installed on the discharge line prior to discharge. Drainage discharge flow meters should also be installed on this line. See also Section 23.3.

26.3.2 Operations

- Monitor flare emissions by calculation and/or direct measurement where applicable. An alternative to direct measurement of flare gas flow is to measure or otherwise determine all contributory flows into the flare gas system. Analysis may be performed to determine flare gas composition. Refer also to Offshore Activity 5 (Section 21).
- Monitor emissions to air by calculation and/or direct measurement, including for example H_2S, BTEX, NOx, SO_2, PM, VOC, CO, CO_2, CH_4 from:
  - Point source emissions to air from combustion emissions and gas flares.
  - Fugitive emissions. Refer also to Offshore Activity 6 (Section 22).
- Monitor diesel fuel and fuel gas usage (if applicable). Report diesel and fuel gas usage and emissions to the Regulatory Authority once a facility is operational.
- Monitor discharges to the environment, e.g. using OIW analyser technology.
- Monitor sediments, e.g. sampling for PAH accumulation, identification and quantification with high-performance liquid chromatography (HPLC) systems [11-13].
- Monitor the seafloor and water column [14], for example in terms of:
  - Physical parameters – e.g. sonar detection techniques for object and leakage detection; automatic analytical techniques to process data and detect areas of impacted seafloor.
  - Geochemical parameters – e.g. monitoring spatial-temporal distribution of natural and leakage-induced marine geochemical anomalies using sampling equipment for gas concentration, temperature, salinity and water pressure.
- Waste monitoring including quantity, waste type/category, chemical composition of waste streams and radioactive substance monitoring (aqueous and solid radioactive waste) [4].

26.4 References for Section 26

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[13] Norwegian Environment Agency (NEA), Region 1 Ekofisk; http://www.miljodirektoratet.no/no/Tema/Miljoovervakning/Miljoovervaking-pa-norsk-sokkel/Bunnhabitatsundersokelser/Rapporter_1/Miljoovervaking-Region-1-2014-Sammendragsrapport--Summary-Report/

[14] Norwegian Environment Agency (NEA), Vannsøyleovervåking og tilstandsovervåking; http://www.miljodirektoratet.no/no/Tema/Miljoovervakning/Miljoovervaking-pa-norsk-sokkel/Vannsoyleovervaking/

Appendix A
Overview of the Information Exchange

The Guidance Document has been drafted based, inter alia, on the information submitted by the Technical Working Group (TWG) as part of an information exchange process.

The information on each activity is based on an extensive review, including existing guidance, standards, regulations and other sources, primarily those identified by members of the TWG as part of the information exchange process.

The process included the following steps:

- Meetings of the TWG: the first meeting was held in autumn 2015 at the start of the project, a second meeting in autumn 2016 further refined the project's scope, and a final meeting in November 2018;
- Meeting of a TWG subgroup held in January 2016: the mandate of the subgroup was to undertake a gap analysis to identify where there is/is not guidance to assist in how to address the key environmental issues covering offshore activities and certain onshore activities and ultimately prioritise the environmental issues that the Guidance Document should cover. The meeting was supported by the prior submission of an initial assessment of data completed by the subgroup (submitted in December 2015) reviewing gaps for each potential environmental issue;
- Consultation on draft dossiers for information collation/exchange (in summer 2017);
- TWG members' inputs to the exchange of information held in late 2017;
- TWG members' comments on the first and second draft of the Guidance Document (submitted in spring and autumn 2018, respectively); and
- Various meetings, discussions and other exchanges with TWG members.

The project team's own knowledge and review of relevant literature have also been used in drafting the Guidance Document. For each activity, some of the most relevant references used are provided, particularly those which include existing guidance and standards identified as most relevant through the above exchange of information. However, the lists of references are not exhaustive.

Appendix B
Abbreviations and Glossary

Abbreviations

Abbreviation	Definition	Abbreviation	Definition
ALARP	As low as reasonably practicable	**DGF**	Dissolved gas floatation
ANSI	American National Standards Institute	**DIAL**	Differential absorption LDAR
API	American Petroleum Institute	**EFS**	Emissions from Storage
BAT	Best available technique	**EIA**	Environmental impact assessment
BATNEEC	Best available techniques not entailing excessive cost	**EIF**	Environmental impact factor
BES	Biodiversity and ecosystem Study	**EMS**	Environmental management system
BOD	Biological oxygen demand	**EMSA**	European Maritime Safety Agency
BREF	BAT reference document	**ENE**	Energy Efficiency
BFROC	Base fluid retained on cuttings	**ENVID**	Environmental (Hazard) Identification
BTEX	Benzene, toluene, ethylene, xylene	**EPL**	Environmental performance level
CBA	Cost-benefit analysis	**EOR**	Enhanced oil recovery
CCAC	Climate and Clean Air Coalition	**ESD**	Emergency Shutdown
CCS	Carbon capture and storage	**ETS**	Emissions trading system
CEN	European Committee for Standardisation	**EU**	European Union
CFU	Compact floatation unit	**EUOAG**	EU Offshore Oil and Gas Authorities Group
CLP Regulation	Classification, Labelling and Packaging Regulation (1272/2008)	**FEM**	Finite element model
COD	Chemical oxygen demand	**FID**	Flame ionisation detector
COMAH	Control of Major Accident Hazards	**FPSO**	Floating production, storage and offloading
CSBI	Cross sector biodiversity initiative	**GEMIR**	Global Environmental Management Initiative
CSM	Conceptual site model	**GHG**	Greenhouse gas
CWW	Common Waste Water Treatment	**HAN**	Heavy aromatic naphtha
DEG	Diethylene glycol	**HEMP**	Hazard and effect management process

HF	Hydraulic fracturing	**NORM**	Naturally occurring radioactive material
HMCS	Harmonised Mandatory Control System (OSPAR)	**NPV**	Net present value
HNS	Hazardous and noxious substances	**OAG**	Offshore Authorities Group
HOCNF	Harmonised Offshore Chemical Notification Format	**OBM**	Oil-based mud
HPLC	High-performance liquid chromatography	**OGI**	Optical gas imaging
HQ	Hazard Quotient	**OGMP**	Oil and gas methane partnership
HSE	Health, safety and environment	**OIW**	Oil in water
HVHF	High volume hydraulic fracturing	**OPEP**	Oil pollution emergency plan
IGF	Induced gas floatation	**OSPAR**	Oslo and Paris Conventions
IRPA	Individual Risk per Annum	**P&A**	Plugging and abandonment
ISSoW	Integrated safe system of work	**PAH**	Polycyclic aromatic hydrocarbons
IEA	International Energy Agency	**PCB**	Polychlorinated biphenyl
IED	Industrial Emissions Directive	**PEC**	Predicated environmental concentration
IMO	International Maritime Organisation	**PID**	Photo-ionisation detector
IRMS	Isotope ratio mass spectroscopy	**PLONOR**	Pose little or no risk
ISD	Inherent safety in design	**PNEC**	Predicated no effect concentration
ISO	International Organisation for Standardisation	**PLL**	Potential Loss of Life
KPI	Key performance indicator	**PPE**	Personal protective equipment
MCP	Medium Combustion Plant	**PTW**	Permit to work
MEG	Monoethylene glycol	**QRA**	Quantitative risk assessment
MoC	Management of change	**REACH Regulation**	Regulation on the Registration, Evaluation, Authorisation and Restriction of Chemicals (Regulation 1907/2006)
MPPE	Macro porous polymer extraction	**SDS**	Safety data sheet (eSDS = extended safety data sheet)
MWEI	Mining waste and extractive industries	**SEA**	Strategic environmental assessment
NADF	Non-aqueous drilling fluids	**SECE**	Safety and environmentally critical element
NMVOC	Non-methane volatile organic compounds	**SIT**	System integrity test

SOF	Solar occultation flux
SVHC	Substances of very high concern
TCC	Thermomechanical cuttings cleaner
TDS	Total dissolved solids
TEG	Triethylene gycol
TLS	Traffic light system
TMAC	Tetramethyl ammonium chloride
TSS	Total suspended solids
TWG	Technical working group
UKOOG	UK Onshore Oil and Gas
VOC	Volatile organic carbon
VSD	Variable speed drive
WBDF	Water based drilling fluids
WFD	Water framework directive (2000/60/EC)
WHRU	Waste heat recovery unit
WRI	World Resources Institute
WT	Waste Treatment

Definitions of commonly used terms[22]

- **Best available techniques** (BAT): BAT means the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques for providing the basis for emission limit values and other permit conditions designed to prevent and, where that is not practicable, to reduce emissions and the impact on the environment as a whole:

  (a) 'techniques' includes both the technology used and the way in which the installation is designed, built, maintained, operated and decommissioned;

  (b) 'available techniques' means those developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages, whether or not the techniques are used or produced inside the Member State in question, as long as they are reasonably accessible to the operator; and

  (c) 'best' means most effective in achieving a high general level of protection of the environment as a whole.

  For clarity, this encompasses techniques that can be used to address both routine (foreseen) and unintended (accidental) emissions and impact on the environment.

- **Discharge**: Planned release of liquid from a hydrocarbons facility to the terrestrial or marine environment.
- **Emission**: Release of gas or other pollutant from a hydrocarbons facility to atmosphere. Emissions may include particulates, vapour phase etc.
- **Environmental performance level**: A quantified value which is expected to be achieved through the application of BAT. This may be, for example a measurement of emissions or discharges in terms of volume and/or frequency.
- **Flowback fluid:** Fluid generated during flowback activities, whereby fluid is allowed to flow from a well following treatment, either in preparation for a subsequent phase of treatment or in preparation for clean-up and return to production.
- **Fugitive emissions:** A type of emission to atmosphere involving the incremental losses of gas from seals and connection points on process equipment and pipework.
- **Hazardous material:** A material containing hazardous substances and warranting classification as a hazardous substance mixture under Regulation (EC) No 1272/2008 or waste under Directive 2008/98/EC.
- **'New' and 'Existing' facilities/installations**: These terms are deliberately not defined within the Guidance Document, nor is what constitutes a facility 'modification' that would warrant implementation of new techniques. This is a matter to be determined between the Regulatory Authority and the hydrocarbons organisation.
- **Non-aqueous drilling fluids (NADF):** Drilling fluids (muds) that contain a non–aqueous organic base fluid (oil or synthetic) as the main liquid component.

[22] http://www.glossary.oilfield.slb.com/Terms/f/flowback.aspx

- **Performance Standard**: An objectively established standard or limit to which a facility, or particular activities, operations or components of that facility are expected to perform under specific conditions.
- **Planned environmental impacts:** Impacts about which the oil/gas organisation and Regulatory Authority have prior knowledge, and which are expected to occur during routine operations. Planned environmental impacts are monitored and are often subject to a regulatory permit.
- **Produced water**: Water deriving from wellbores in oil and gas production that includes formation water from the reservoir, condensation water and re-produced injection water.
- **Regulatory Authority**: Regulatory/permitting authorities for hydrocarbons activities, including for jurisdictions where either a single or multiple such authorities exist.
- **Risk**: Effect of uncertainty on objectives. An effect is a deviation from the expected — positive and/or negative. Objectives can have different aspects (such as financial, health and safety, and environmental goals) and can apply at different levels (such as strategic, organisation-wide, project, product and process). Risk is often characterised by reference to potential events and consequences, or a combination of these. Risk is often expressed in terms of a combination of the consequences of an event (including changes in circumstances) and the associated likelihood of occurrence (ISO Guide 73:2009). In the context of the Guidance Document, the primary focus is on risks to the environment.
- **Risk management**: Coordinated activities to direct and control an organisation with regard to risk (ISO Guide 73:2009).
- **Risk management framework**: A set of components that provide the foundations and organisational arrangements for designing, implementing, monitoring, reviewing and continually improving risk management throughout the organisation. The foundations include the policy, objectives, mandate and commitment to manage risk. The organisational arrangements include plans, relationships, accountabilities, resources, processes and activities. The risk management framework is embedded within the organisation's overall strategic and operational policies and practices. (ISO Guide 73:2009).
- **Unintended environmental impacts:** Impacts that are not expected to occur during routine operations but for which the potential occurrence is anticipated and managed through the application of risk management approaches. Includes accidents and environmental incidents.
- **Venting:** A type of emission to atmosphere involving the release of uncombusted gas from facility process systems and storage.
- **Water based drilling fluids (WBDFs):** Drilling fluids (muds) containing water as the main liquid component.

Appendix C
Performing a BAT Assessment

Performing a BAT assessment for the purpose of the application of this guidance is an effective means of evaluating an operation – at the level of project, process or site – to arrive at an appropriate solution resulting in the least environmental impact given a set of cost and benefit constraints. The concept of BAT implies that different techniques, or design options, should be evaluated in the development of facilities and their methods of operation, to prevent or reduce impacts on the environment.

The greatest opportunity for impact reduction via BAT occurs during the earliest operational stage, and it is hence desirable to initiate BAT assessment as a high-level appraisal process at this stage. The assessment may then be subject to update and be developed in greater detail as more information is obtained. Indeed, BAT should be identified in consecutive phases, and assessments performed to ensure that opportunities for reducing environmental impact have been captured.

In overview, performing a BAT assessment may be considered as a stepwise process as follows:

1. Define options/techniques;
2. Quantify environmental aspects and impacts;
3. Perform detailed options selection;
4. Perform cost-benefit review; and
5. Select option that represents BAT.

Further detail on each of these steps is provided in the following Sections.

Define options/techniques

Operational scope (i.e. project, process, site) should be defined, and relevant options and techniques identified. Applicable lifecycle phases (e.g. exploration, production, decommissioning) should also be identified and process, material and energy boundaries characterised. For modifications to existing facilities, separation between existing and new infrastructure should be clarified. If appropriate techniques are described in relevant BREFs or other regulatory guidance these should be included. This step should ensure that the options/techniques selected for more detailed review are based on sound environmental, safety and technical feasibility criteria. If a high-level screening of options/techniques is performed at this stage, it should clearly document why options are eliminated and others taken forward, to provide an audit trail.

Quantify environmental aspects and impacts

Environmental aspects (e.g. emissions, discharges, raw material and energy use) should be identified and characterised for each option. Approaches for achieving this include Environmental Hazard Identification (ENVID) and Environmental Aspects and Impacts Register (Section 3.5.8). Data relevant to environmental aspects should be obtained that is of a level of detail suitable for informed decision making. This stage of the assessment also requires collection and analysis of relevant data to characterise the local environment (e.g. environmental baseline). Once aspects are known, environmental impacts should be quantified, beginning at a high level, screening for insignificant impacts, and then performing further analysis if required. Impacts should be compared with environmental benchmarks using standardised and credible methodologies.

Perform detailed options selection

This step involves comparing the overall environmental performance of each option in order to identify which represents the lowest impact. Options selection may be carried out in a variety of different ways depending on the needs of a specific operation. The outcome should be a ranking of options according to environmental performance. A weighting system is typically used to arrive at this ranking, with impacts and their scores weighted according to relative importance and priorities set for impact reduction. Weighting factors can be adjusted to reflect operational circumstances, e.g. to amplify the importance of environmental sensitivities or reduce the importance of environmental impacts that are not relevant to a project. Trade-offs should also be considered between BAT options as regards cross-media effects with the process accounting for how different options may be combined in a way that leads to the least overall environmental impact.

Perform cost-benefit review

The aim of this step is to estimate the costs of implementing each of the options carried forward from the previous steps, in order to allow a balanced judgement of the costs against the environmental benefits. Examples of cost factors that may be included are: CAPEX and OPEX, timescale, EU ETS costs for CO_2, operator familiarity and training requirements, compatibility with existing systems, availability of equipment and spares, maintenance, etc. If environmental liabilities and risks are to be considered, scenarios that may result in pollution should be evaluated, including normal and abnormal operating conditions, process upsets, pollution incidents, likely frequencies of such incidents and clean-up costs. Net present value (NPV) associated with each option should also consider end-of-life and decommissioning costs.

Select option that represents BAT

The option that represents BAT may be selected based on the outcome of the above steps. The option with the most favourable score and if relevant, the lowest NPV, represents the BAT solution.

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