



Environmental, Health, and Safety Guidelines for Offshore Oil and Gas Development

Introduction

1. The Environmental, Health, and Safety (EHS) Guidelines are technical reference documents with general and industry-specific examples of Good International Industry Practice (GIIP).¹ When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. These industry sector EHS guidelines are designed to be used together with the **General EHS Guidelines** document, which provides guidance to users on common EHS issues potentially applicable to all industry sectors. For complex projects, use of multiple industry sector guidelines may be necessary. A complete list of industry sector guidelines can be found at: www.ifc.org/ehsguidelines.
2. The EHS Guidelines contain the performance levels and measures that are generally considered to be achievable in new facilities by existing technology at reasonable costs. Application of the EHS Guidelines to existing facilities may involve the establishment of site-specific targets, with an appropriate timetable for achieving them.
3. The applicability of the EHS Guidelines should be tailored to the hazards and risks established for each project on the basis of the results of an environmental assessment in which site-specific variables, such as host country context, assimilative capacity of the environment, and other project factors, are taken into account. The applicability of specific technical recommendations should be based on the professional opinion of qualified and experienced persons.
4. When host country regulations differ from the levels and measures presented in the EHS Guidelines, projects are expected to achieve whichever are more stringent. If less stringent levels or measures than those provided in these EHS Guidelines are appropriate, in view of specific project circumstances, a full and detailed justification for any proposed alternatives is needed as part of the site-specific environmental assessment. This justification should demonstrate that the choice for any alternate performance levels is protective of human health and the environment.

¹ Defined as the exercise of professional skill, diligence, prudence and foresight that would be reasonably expected from skilled and experienced professionals engaged in the same type of undertaking under the same or similar circumstances globally. The circumstances that skilled and experienced professionals may find when evaluating the range of pollution prevention and control techniques available to a project may include, but are not limited to, varying levels of environmental degradation and environmental assimilative capacity as well as varying levels of financial and technical feasibility.

Applicability

5. The EHS Guidelines for Offshore Oil and Gas Development include information relevant to seismic exploration, exploratory and production drilling, development and production activities, offshore pipeline operations, offshore transportation, tanker loading and unloading, ancillary and support operations, and decommissioning. They also address potential onshore impacts that may result from offshore oil and gas activities. This document is organized according to the following sections:

Section 1.0 — Industry-Specific Impacts and Management

Section 2.0 — Performance Indicators and Monitoring

Section 3.0 — References

Annex A — General Description of Industry Activities

1.0 Industry-Specific Impacts and Management

6. This section provides a summary of EHS issues associated with offshore oil and gas development, along with recommendations for their management. These issues may be relevant to any of the activities listed as applicable to these guidelines. Guidance for the management of EHS issues common to most large industrial facilities during the construction phase is provided in the **General EHS Guidelines**.

1.1 Environment

7. The following environmental issues should be considered as part of a comprehensive assessment and management program that addresses project-specific risks and potential impacts. Potential environmental issues associated with offshore oil and gas development projects include the following:

- Air emissions
- Wastewater discharges
- Solid and liquid waste management
- Noise generation (including underwater)
- Spills
- Energy efficiency and resource conservation

Air Emissions

8. The main sources of air emissions (continuous or intermittent) resulting from offshore activities include: combustion sources from power and heat generation; the use of compressors, pumps, and reciprocating engines (boilers, turbines, and other engines) on offshore facilities, including support and supply vessels and helicopters; emissions resulting from flaring and venting of hydrocarbons; and fugitive emissions.

9. The main component of these emission sources is carbon dioxide (CO₂). Principal pollutants include nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), and particulates. Additional pollutants can include: hydrogen sulfide (H₂S); volatile organic compounds (VOCs) methane and ethane; benzene, ethyl benzene, toluene, and xylenes (BTEX); glycols; and polycyclic aromatic hydrocarbons (PAHs). Firefighting and refrigeration systems may contain Halon and chlorofluorocarbons.²

² See also http://www.oilandgasuk.co.uk/knowledgecentre/atmospheric_emissions.cfm.

10. Significant (>25,000 tons CO₂ equivalent per year) greenhouse gas (GHG) emissions from all facilities and offshore support activities should be quantified annually as aggregate emissions, in accordance with internationally recognized methodologies and reporting procedures.

11. All reasonable attempts should be made to maximize energy efficiency and design facilities for lowest energy use. The overall objective is to reduce air emissions. Cost-effective and technically feasible options for reducing emissions should be evaluated. Additional recommendations on the management of greenhouse gases and energy conservation are addressed in the **General EHS Guidelines**.

Exhaust Gases

12. Exhaust gas emissions produced by the combustion of gas or liquid fuels in turbines, boilers, compressors, pumps, and other engines for power and heat generation, or for water injection or oil and gas export, can be the most significant source of air emissions from offshore facilities. During equipment selection, air emission specifications should be considered.

13. Guidance for the management of small combustion source emissions with a capacity of up to 50 megawatt thermal (MWth), including air emission standards for exhaust emissions, is provided in the **General EHS Guidelines**. For combustion source emissions with a capacity of greater than 50 MWth, refer to the **EHS Guidelines for Thermal Power**.

Venting and Flaring

14. Associated gas brought to the surface with crude oil during oil production is sometimes disposed of at offshore facilities by venting or flaring. This practice is now widely recognized to be a waste of valuable resources, as well as a significant source of GHG emissions.

15. However, flaring and venting are important safety measures on offshore oil and gas facilities to ensure that gas and other hydrocarbons are safely disposed of in the event of an emergency, a power or equipment failure, or other plant upset condition. Risk assessment processes (e.g., hazard and operability study (HAZOP), hazard identification study (HAZID), etc.) to estimate and record the potential discharges are used in such facilities.

16. Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard³ (part of the World Bank Group's Global Gas Flaring Reduction Public-Private Partnership, GGFR program)

³ World Bank 2004. <http://documents.worldbank.org/curated/en/2004/05/4946640/voluntary-standard-global-gas-flaring-venting-reduction>.

should be adopted when considering venting and flaring options for offshore activities. The standard provides guidance on how to eliminate or achieve reductions in the flaring and venting of natural gas.

17. Continuous venting of associated gas is not good practice and should be avoided. The associated gas stream should be routed to an efficient flare system, although continuous flaring of gas should be avoided if alternatives are available. Before flaring is adopted, all feasible⁴ alternatives for the gas's use should be evaluated to the maximum extent possible and integrated into production design.

18. Alternative options may include gas utilization for on-site energy needs, gas injection for reservoir pressure maintenance, enhanced recovery using gas lift, or export of the gas to a neighboring facility or to market. An assessment of alternatives should be adequately documented. If none of the options for the associated gas's use is feasible, measures to minimize flare volumes should be evaluated and flaring should be considered as an interim solution, with the elimination of continuous production-associated gas flaring as the preferred goal.

19. New facilities should be designed, constructed, and operated so as to avoid routine flaring. Cost-effective options to reduce flaring from existing/legacy facilities that offer sustainable social benefits (e.g., gas-to-power) should be identified and evaluated in collaboration with host country governments and other stakeholders and with a particular focus on GHG emissions.

20. If flaring is the only viable solution, continuous improvement of flaring through the implementation of good practices and new technologies should be demonstrated. The following pollution prevention and control measures should be considered for gas flaring:

- Implement source gas reduction measures to the extent possible.
- Use efficient flare tips, and optimize the size and number of burning nozzles.
- Maximize flare combustion efficiency by controlling and optimizing flare fuel/air/steam flow rates to ensure the correct ratio of assist stream to flare stream.
- Minimize flaring from purges and pilots—without compromising safety—through measures including installation of purge gas reduction devices, flare gas recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots.
- Minimize risk of pilot blow-out by ensuring sufficient exit velocity and providing wind guards.
- Use a reliable pilot ignition system.
- Install high-integrity instrument pressure protection systems, where appropriate, to reduce over-pressure events and avoid or reduce flaring situations.

⁴ Ibid.

- Minimize liquid carryover and entrainment in the gas flare stream with a suitable liquid separation system.
- Minimize flame lift off and/or flame lick.
- Operate flare to control odor and visible smoke emissions (no visible black smoke).
- Situate flare at a safe distance from accommodation units.
- Implement burner maintenance and replacement programs to ensure continuous maximum flare efficiency.
- Meter flare gas.

21. In the event of an emergency or equipment breakdown, or when faced with plant upset conditions, excess gas should not be vented but rather sent to an efficient flare gas system. Emergency venting may be necessary under specific field conditions where flaring of the gas stream is not possible, or where a flare gas system is not available, such as a lack of sufficient hydrocarbon content in the gas stream to support combustion or a lack of sufficient gas pressure to allow it to enter the flare system. Justification for excluding a gas flaring system on offshore facilities should be fully documented before an emergency gas venting facility is considered.

22. To minimize flaring events as a result of equipment breakdowns and plant upsets, plant reliability should be high (>95 percent) and provisions should be made for equipment sparing and plant turn-down protocols.

23. Flaring volumes for new facilities should be estimated during the initial commissioning period so that appropriate flaring targets can be developed. The volumes of gas flared for all flaring events should be recorded and reported.

Well Testing

24. During well testing, flaring of produced hydrocarbons should be avoided, especially in environmentally sensitive areas. Feasible alternatives should be evaluated for the recovery of these test fluids, while considering the safety of handling volatile hydrocarbons, either for transfer to a processing facility or for alternative disposal options. An evaluation of alternatives for produced hydrocarbons should be adequately documented.

25. If flaring is the only option available for the disposal of test fluids, only the minimum volume of hydrocarbons required for the test should be flowed and well test durations should be reduced to the extent practical. An efficient test flare burner head equipped with an appropriate combustion

enhancement system should be selected to minimize incomplete combustion, black smoke, and hydrocarbon fallout to the sea. Volumes of hydrocarbons flared should be recorded.

Fugitive Emissions

26. Fugitive emissions in offshore facilities may be associated with cold vents, leaking tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, and hydrocarbon loading and unloading operations.

27. Methods for controlling and reducing fugitive emissions should be considered and implemented in the design, operation, and maintenance of offshore facilities. The selection of appropriate valves, flanges, fittings, seals, and packings should consider safety and suitability requirements, as well as their capacity to reduce gas leaks and fugitive emissions. Additionally, leak detection and repair programs should be implemented.

Wastewaters

Produced Water

28. Oil and gas reservoirs contain water (formation water) that becomes produced water when brought to the surface during hydrocarbon production. Oil reservoirs can contain large volumes of this water, whereas gas reservoirs typically produce smaller quantities. A specific case is that of Coal Bed Methane (CBM) reservoirs, from which a large amount of produced water is generated. CBM reservoirs are infrequently exploited offshore. In addition, in many fields, water is injected into the reservoir to maintain pressure and/or maximize production. The total produced water stream can be one of the largest waste products, by volume, and therefore requires management by offshore operations.

29. Produced water contains a complex mixture of inorganic (dissolved salts, trace concentrations of certain metals, suspended particles), organic (free and trace concentrations of dissolved hydrocarbons), and in some cases, residual trace concentrations of chemical additives (for example, scale and corrosion inhibitors, hydrate inhibitors), that are sometimes used to enhance the hydrocarbon production process.

30. Feasible alternatives to the management and disposal of produced water should be evaluated and integrated into production design. These alternatives may include injection along with seawater for reservoir pressure maintenance, injection into a suitable offshore disposal well, or export to shore with produced hydrocarbons for treatment and disposal.

31. When disposal wells are the adopted solution, geological and technical aspects should be considered, to avoid leakage of the disposed water to the seabed or shallow confined aquifers. The

conversion of existing wells to injection wells should be considered first, to minimize both geological risk and the construction costs of dedicated disposal wells.

32. If none of these alternatives is technically or financially feasible, the Environmental and Social Impact Assessment (ESIA) should establish mitigation targets for produced water according to the discharge guidelines provided in Table 1 of Section 2 prior to its disposal into the marine environment.

33. Treatment technologies to consider include combinations of gravity and/or mechanical separation and chemical treatment, and may include a multistage system, typically including a skim tank or a parallel plate separator, followed by a gas flotation cell or hydrocyclone. A number of treatment package technologies are available and should be considered, depending on the application and particular field conditions.

34. Sufficient treatment system backup capability should be in place to ensure continual operation and should be available for use if an alternative disposal method—for example, a produced water injection system—should fail.

35. Where disposal to sea is necessary, all means to reduce the volume of produced water should be considered, including:

- Adequate well management during well completion activities to minimize water production.
- Recompletion of high water-producing wells to minimize water production.
- Use of downhole fluid separation techniques, where possible, and water shutoff techniques, when technically and economically feasible.
- Shutting off in high water-producing wells.

36. To minimize environmental hazards related to residual chemical additives in the produced water stream, where surface disposal methods are used, production chemicals should be selected carefully by taking into account their application rate, toxicity, bioavailability, and bioaccumulation potential. In particular, the use and dispersion of Kinetic Hydrate Inhibitors (KHI) should be assessed to avoid possible accumulation of poorly degraded residuals.

Hydraulic Fracturing

37. If hydraulic fracturing is planned or forms part of the project, as in the case of shale gas projects or CBM, all environmental aspects—including fracture propagation, fracturing fluid management, and the fate and management of flowback water—should be evaluated.⁵

Flowback Water

38. The water that flows back from the well to the surface after hydraulic fracturing, generally referred to as “flowback water,” requires considerations separate from or in addition to those bearing on produced water. Flowback water characteristics depend on the type of fluid injected to induce rock fracturing and can also be present in large quantities. Flowback water can thus constitute the main environmental management issue for hydraulic fracturing operations.

39. Feasible alternatives for the management and disposal of flowback water should be evaluated and integrated into operational design. Alternatives may include injection into a suitable offshore disposal well, temporary storage for re-use in further hydraulic fracturing operations, or the export of flowback water to shore with the produced hydrocarbons for treatment and disposal. If none of these alternatives is technically or economically feasible, flowback water should be treated according to the discharge guidelines provided in Table 1 of Section 2 for oil and grease content prior to its disposal into the marine environment. An assessment of alternatives should be adequately documented. In addition, an environmental risk assessment on the chemicals mixed with the hydraulic fracturing water—including their toxicity, bioavailability, and bioaccumulation potential—should be conducted to assess the maximum site-specific allowable concentrations.

Hydrostatic Testing Water

40. Hydrostatic testing of offshore equipment and marine pipelines involves pressure testing with water (typically filtered seawater, unless equipment specifications do not allow it) to verify equipment and pipeline integrity. Chemical additives (corrosion inhibitors, oxygen scavengers, biocides, and dyes) may be added to the water to prevent internal corrosion or to identify leaks. In managing hydrotest waters, the following pollution prevention and control measures should be considered:

- Minimize the volume of hydrotest water offshore by testing equipment at an onshore site prior to loading the equipment onto the offshore facilities.
- Use the same water for multiple tests.

⁵ Any possible social concerns (for example, related to induced micro seismicity) should also be assessed.

- Reduce the need for chemicals by minimizing the time that test water remains in the equipment or pipeline.
- Carefully select chemical additives in terms of dose concentration, toxicity, biodegradability, bioavailability, and bioaccumulation potential.
- Send offshore pipeline hydrotest water to onshore facilities for treatment and disposal, where practical.

41. If the discharge of hydrotest waters to the sea is the only feasible alternative for disposal, a hydrotest water disposal plan should be prepared that considers points of discharge, rate of discharge, chemical use and dispersion, environmental risk, and monitoring. Hydrotest water disposal into shallow coastal waters and sensitive ecosystems should be avoided.

Cooling Water

42. Antifoulant chemical dosing to prevent marine fouling of offshore facility cooling water systems should be carefully considered. Available alternatives should be evaluated and, where practical, the seawater intake depth should be optimized to reduce the need for use of chemicals. An assessment of alternatives should be adequately documented. Appropriate screens should be fitted to the seawater intake, if safe and practical.

43. The cooling water discharge depth should be selected to maximize mixing and cooling of the thermal plume to ensure that the temperature is within 3 degrees Celsius of ambient seawater temperature at the edge of the defined mixing zone, or if the mixing zone is not defined, within 100 meters of the discharge point, as noted in Table 1 of Section 2 of these Guidelines.

Desalination Brine

44. Operators should consider mixing desalination brine from the potable water system with cooling water. If mixing with other discharge streams is not feasible, the discharge location should be carefully selected with respect to potential environmental impacts. In particular, in the case of coastal and/or brackish water, the salinity of the rejected effluent should be reduced by adjusting the Reverse Osmosis (RO) process.

Other Waste Waters

45. Other waste waters routinely generated at offshore facilities are listed below, along with appropriate treatment measures:

- *Sewage*: Gray and black water from showers, toilets, and kitchen facilities should be treated in an appropriate on-site marine sanitary treatment unit in compliance with MARPOL 73/78 requirements.
- *Food waste*: Organic (food) waste from the kitchen should, at a minimum, be macerated to acceptable levels and discharged to sea, in compliance with MARPOL 73/78 requirements.
- *Storage displacement water*: Water pumped into and out of storage during loading and off-loading operations should be contained and treated before discharge to meet the guidelines provided in Table 1 of Section 2.
- *Bilge waters*: Bilge waters from machinery spaces in offshore facilities and support vessels should be routed to the facility's closed drainage system, or contained and treated before discharge to meet the guidelines provided in Table 1 of Section 2. If treatment to this standard is not possible, these waters should be contained and shipped to shore for disposal.
- *Deck drainage water*: Drainage water generated from precipitation, sea spray, or routine operations, such as deck and equipment cleaning and fire drills, should be routed to separate drainage systems in offshore facilities. This includes drainage water from process areas that could be contaminated with oil (closed drains) and drainage water from non-process areas (open drains). All process areas should be bunded to ensure that drainage water flows into the closed drainage system. Drip trays should be used to collect runoff from equipment that is not contained within a bunded area and the contents routed to the closed drainage system. Contaminated drainage waters should be treated before discharge to meet the guidelines provided in Table 1 of Section 2.

Waste Management

46. Typical non-hazardous and hazardous wastes⁶ routinely generated at offshore facilities include general office and packaging wastes, waste oils, oil-contaminated rags, hydraulic fluids, used batteries, paint cans, waste chemicals and used chemical containers, used filters, fluorescent tubes, scrap metals, and medical waste, among others.

47. At a minimum, these waste materials should be segregated offshore into non-hazardous and hazardous wastes, and shipped to shore for re-use, recycling, or disposal. A waste management plan for the offshore facility should be developed and should contain a mechanism allowing waste consignments to be tracked from the originating location offshore to the final waste treatment and disposal location onshore. Efforts should be made to eliminate, reduce, or recycle waste at all times.

⁶ As defined by local legislation or international conventions.

48. Guidance for onshore management of these typical wastes is provided in the **General EHS Guidelines**.

49. Additional waste streams associated with offshore development activities include:

- Drilling fluids and drilled cuttings
- Produced sand
- Completion and well work-over fluids
- Naturally occurring radioactive materials (NORM)

Drilling Fluids and Drilled Cuttings

50. The primary functions of drilling fluids used in oil and gas field operations include removal of drilled cuttings (rock chippings) from the wellbore and control of formation pressures. Other important functions include sealing permeable formations, maintaining wellbore stability, cooling and lubricating the drill bit, and transmitting hydraulic energy to the drilling tools and bit. Drilled cuttings removed from the wellbore and spent drilling fluids are typically the largest waste streams, by volume, generated during oil and gas drilling activities.

51. Though various drilling fluids are available, they can generally be categorized into:

- *Water-Based Drilling Fluids (WBDF)*: Fluids for which the continuous phase and suspending medium for solids is seawater or a water-miscible fluid. There are many WBDF variations, including gel, salt-polymer, salt-glycol, and salt-silicate fluids.
- *Non-Aqueous Drilling Fluids (NADF)*: The continuous phase and suspending medium for solids is a water-immiscible fluid that is oil-based, enhanced mineral oil-based, or synthetic-based.

52. The selection of a drilling fluid should be made after evaluating its technical suitability and environmental impact. The use of fluids that contain diesel as the principal component of the liquid phase is not good practice for offshore drilling programs and should be avoided.

53. Typically, barite (barium sulfate) is the solid medium used to increase the specific density of most drilling fluids, with bentonite clays also used as a thickener. Drilling fluids contain a number of additional chemicals, depending on the downhole formation conditions.

54. Drilling fluids are (i) circulated downhole with direct loss to the seabed, along with displaced cuttings, particularly while drilling well sections nearest to the surface of the seabed; or (ii) recovered for re-use

when returned to the drilling rig via casing or marine riser and routed to a solids removal system. The direct loss system is to be considered an interim solution for the first drilling phase and only applied when the chemical content is low, or water-based drilling mud is used.

55. In the solids removal system, the drilling fluids are separated from the cuttings so that they may be recirculated downhole, leaving the cuttings behind for disposal. The volume of cuttings produced will depend on the depth of the well and the diameter of the hole sections drilled. The cuttings contain residual drilling fluid.

56. The drilling fluid rheological properties and density are adjusted during drilling via solid control systems; the fluid is eventually replaced (i) when its rheological properties or density can no longer be maintained, or (ii) at the end of the drilling program. These spent fluids are then contained for reuse or disposal. Disposal of spent NADF by discharge to the sea must be avoided. Instead, NADF should be transferred to shore for recycling or treatment and disposal.

57. Feasible alternatives for the disposal of spent WBDF and drilled cuttings from well sections drilled with either WBDF or NADF should be evaluated. Options include injection into a dedicated disposal well offshore, injection into the annular space of a well, and containment and transfer to shore for treatment and disposal. When no alternative options are available, residual WBDF might be discharged to sea at the end of a drilling program, provided that the overall ESIA conducted for the site has considered this scenario, demonstrating the environmental acceptability of this practice.

58. When discharge to sea is the only alternative, a drilled cuttings and fluid disposal plan should be prepared, taking into account cuttings and fluid dispersion, chemical use, environmental risk, and necessary monitoring. Discharge of cuttings to sea from wells drilled with NADF should be avoided. If discharge is necessary, cuttings should be treated before discharge to meet the guidelines provided in Table 1 of Section 2.

59. Guidance for the treatment and disposal of fluids and cuttings shipped to shore is provided in the EHS Guidelines for Onshore Oil and Gas Development.

60. Pollution prevention and control measures to consider prior to the discharge of spent drilling fluids and drilled cuttings should include:

- Minimize environmental hazards related to residual chemical additives on discharged cuttings by careful selection of the fluid system. WBDFs should be selected whenever appropriate.

- Carefully select fluid additives, taking into account their concentration, toxicity, bioavailability, and bioaccumulation potential.
- Use high-efficiency solids control equipment to reduce the need for fluid change out.
- Use high-efficiency solids removal and treatment equipment to reduce and minimize the amount of residual fluid contained in drilled cuttings.
- Use directional drilling (horizontal and extended reach) techniques to avoid sensitive surface areas and to gain access to the reservoir from less sensitive surface areas.
- Use slim-hole multilateral wells and coiled tubing drilling techniques, when feasible, to reduce the amount of fluids and cuttings.

61. Drilling fluids to be discharged to sea (including as residual material on drilled cuttings) are subject to tests for toxicity, barite contamination, and oil content provided in Table 1 of Section 2. Barite contamination by mercury (Hg) and cadmium (Cd) must be checked to ensure compliance with the discharge limits provided in Table 1. Suppliers should be asked to guarantee that barite quality meets this standard with pre-treatment, if necessary.

62. All discharges should be made via a caisson submerged at an appropriate depth (indicatively 15 meters below the sea surface) to ensure suitable dispersion of the effluent; in shallow and calm water, the caisson depth could be reduced, according to the discharge point characteristics.

Produced Sand

63. Produced sand originating from the reservoir is separated from the formation fluids during hydrocarbon processing. The produced sand can contain hydrocarbons, and the hydrocarbon content can vary substantially, depending on location, depth, and reservoir characteristics. Well completion should aim to reduce the production of sand at source using effective downhole sand control measures.

64. Whenever practical, produced sand removed from process equipment should be transported to shore for treatment and disposal, or routed to an offshore injection disposal well if available. Discharge to sea is not good practice. If discharge to sea is the only demonstrably feasible option, then the discharge should meet the guideline values in Table 1 of Section 2.

65. Any oily water generated from the treatment of produced sand should be recovered and treated to meet the guideline values for produced water in Table 1 of Section 2.

Completion and Well Work-Over Fluids

66. Completion and well work-over fluids (including intervention fluids and service fluids) typically includes weighted brines or acids, methanol and glycols, and other chemical systems. These fluids are used to clean the wellbore and stimulate the flow of hydrocarbons, or may be used to maintain downhole pressure. Once used, these fluids may contain contaminants including solid material, oil, and chemical additives.

67. Feasible disposal options should be considered, including:

- Collect the fluids where handled in closed systems and ship onshore to the original vendors for recycling.
- Inject in a disposal well, where available.
- Ship onshore for treatment and disposal.

68. If discharge to sea is the only demonstrably feasible option:

- Select chemical systems in relation to their concentration, toxicity, bioavailability, and bioaccumulation potential.
- Consider routing these fluids to the produced water stream for treatment and disposal, if available.
- Neutralize spent acids before treatment and disposal.
- Ensure the fluids meet the discharge levels in Table 1 of Section 2.

Naturally Occurring Radioactive Materials (NORM)

69. Depending on the field reservoir characteristics, naturally occurring radioactive material (NORM)⁷ may be present in the produced fluids. NORM may precipitate as scale or sludge in process piping and production vessels⁸ in which the concentration of NORM can be higher than in the fluid). Where NORM is present, a NORM management program should be developed to ensure the use of appropriate handling procedures.

70. If removal of NORM is required, disposal options may include: canister disposal during well abandonment; injection into the annular space of a well; shipment to shore for disposal in a landfill within

⁷ Defined as "Radioactive material containing no significant amounts of radionuclides other than naturally occurring radionuclides. Material in which the activity concentrations of the naturally occurring radionuclides have been changed by some process are included in NORM." International Commission on Radiological Protection. 2007. "The 2007 Recommendations of the International Commission on Radiological Protection." ICRP Publication 103. Ann. ICRP 37 (2–4).

⁸ See International Oil and Gas Producers Association (OGP) 2008a. "Guidelines for the Management of Naturally Occurring Radioactive Material (NORM) in the Oil and Gas Industry." Report No. 412. September 2008. OGP.

sealed containers; and, depending on the type of NORM and in cases where no other option is available, discharge to sea with the facility drainage.

71. NORM-containing sludge, scale, or equipment should be treated, processed, isolated and/or disposed of according to good international industry practices,⁹ so that potential future human exposure to the treated waste would be within internationally accepted limits.¹⁰

Hazardous Materials Management

72. Hazardous materials are used in offshore oil and gas operations. General guidance for the management of hazardous materials is provided in the **General EHS Guidelines**.

73. The following additional principles should be followed for offshore chemicals:

- Use chemical hazard assessment and risk management techniques to evaluate chemicals and their effects.
- Only select those chemicals that have been previously tested for environmental hazards.
- Select chemicals based on the OSPAR¹¹ Harmonized Offshore Chemical Notification Format (HOCNF), or similar internationally recognized system.
- Select chemicals with the least hazard and lowest potential environmental and health impacts, whenever possible.
- Avoid chemicals suspected to cause taint or known endocrine disruptors.
- For new offshore oil and gas facilities, Ozone Depleting Substances should not be used;¹² action plans for phasing-out Ozone Depleting Substances present in existing facilities should be developed and documented.
- Avoid chemicals known to contain heavy metals, in anything other than trace quantities.

Noise

74. Offshore oil and gas development activities generating noise include seismic operations, drilling and production activities, offshore and nearshore structural installation (especially pile driving) and

⁹ For more on the management of NORM residues, see: International Atomic Energy Agency (IAEA). 2013. "Management of NORM Residues." IAEA–TECDOC series. ISSN 1011-4289. No. 1712. IAEA.

¹⁰ ICRP 2007.

¹¹ Oslo—Paris Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), <http://www.ospar.org/>

¹² As defined by the Montreal Protocol on substances that deplete the ozone layer.

construction activities, and marine traffic. Noise from offshore activities (especially from seismic operations) can temporarily affect fish and marine mammals.¹³

75. Environmental parameters that determine sound propagation in the sea are site-specific, and different species of marine life have different hearing sensitivities as a function of frequency. An impact assessment should be conducted to (i) identify where and/or when anthropogenic sound has the potential to create significant impacts and (ii) determine what mitigation measures, if any, are appropriate. Recommended measures to reduce the risk of sound impact to marine species include:

- Identify sensitive areas for marine life, such as feeding, breeding, calving, and spawning grounds.
- Plan seismic surveys and offshore construction activities so as to avoid sensitive times of the year.
- Identify fishing areas and reduce disturbances by scheduling seismic surveys and construction activities for less productive times of the year, where possible.
- Maximize the efficiency of seismic surveys to reduce operation times, where possible.
- If sensitive species are anticipated in the area, monitor their presence before the onset of sound-creating activities that have the potential to produce adverse effects, and continue monitoring throughout the seismic program or construction. In areas where significant impacts to sensitive species are anticipated, use experienced observers.
- When marine mammals are observed congregating close to the area of planned activities, seismic start-up or construction should begin at least 500 meters away.
- If marine mammals are sighted within 500 meters of the proposed seismic array or construction area, postpone start-up of seismic activities or construction until they have moved away, allowing adequate time after the last sighting.
- Use soft-start procedures—also called ramp-up or slow buildup—in areas of known marine mammal activity. This involves a gradual increase in sound pressure to full operational levels.
- Use the lowest practicable power levels to image the target surface throughout the seismic surveys and document their use.
- Where possible, use methods to reduce and/or baffle unnecessary high-frequency noise produced by air guns or other acoustic energy sources.

¹³ See Joint Nature Conservation Committee (JNCC) Guidelines 2010, International Association of Geophysical Contractors (IAGC) 2011, Joint OGP/IAGC Position Paper 2011, and further references in Section 3.0.

Spills

76. Spills from offshore facilities can occur due to leaks, equipment failure, accidents, or human error. Guidelines for release prevention and control planning are provided in the **General EHS Guidelines**, including the requirement to develop a spill prevention and control plan. Additional spill prevention and control measures specific to offshore oil and gas facilities include:

- Conduct a spill risk assessment for offshore facilities and support vessels.
- Design process, utility, and drilling systems to reduce the risk of major uncontained spills.
- Install valves—including subsea shutdown valves, if required—for the reduction of risk, to allow early shutdown or isolation in an emergency.
- Ensure adequate corrosion allowance for the lifetime of the facilities and/or installation of corrosion control and prevention systems in all pipelines, process equipment, and tanks.
- Develop maintenance and monitoring programs to ensure the integrity of well field equipment. For export pipelines, maintenance programs should include regular pigging to clean the pipeline, and intelligent pigging should also be considered as required.
- Install leak detection systems. Use subsea pipeline measures, such as telemetry systems, SCADA¹⁴ systems, pressure sensors, shut-in valves, and pump-off systems, as well as normally unattended installations and unmanned facilities to ensure rapid detection of loss of containment.
- For facilities with potentially significant releases, install an Emergency Shutdown System that initiates automatic shutdown actions to bring the offshore facility to a safe condition.
- Implement adequate personnel training in oil spill prevention, containment, and response.
- Ensure that spill response and containment equipment is deployed or available as necessary for response.
- Document and report all spills. Following a spill, carry out a root cause investigation and undertake corrective actions to prevent recurrence.

Spill Response Planning

77. A Spill Response Plan (SRP) is required, along with the capability to implement the plan. Prepare a preliminary SRP, commencing at the project development phase and based on the initial project design, including community consultation and feedback.

¹⁴ SCADA refers to supervisory control and data acquisition systems, which may be used in oil and gas and other industrial facilities to assist in the monitoring and control of plants and equipment.

78. The SRP should address potential oil, chemical, and fuel spills from offshore facilities, and support vessels—including tankers—and pipeline ruptures. The plan should include:

- A description of operations, site conditions, product(s) characteristics, current and wind data, sea conditions and water depth, and logistical support.
- Spill risk assessment, defining expected frequency and size of spills from potential release sources, including assessment of foreseeable scenarios.
- Ranking of foreseeable spill scenarios in terms of potential severity, with tiered response approaches for each.
- Identification of persons responsible for managing and participating in spill response efforts, their specific responsibilities, authority, roles, and contact details.
- Sensitivity mapping of marine and coastal environmental components that could be affected by spills generated by offshore oil and gas development and production activities.¹⁵
- Cooperative measures with government agencies, if appropriate.

79. The SRP should also include:

- Clear demarcation of spill severity, according to the size of the spill, using a clearly defined Tier I, Tier II, and Tier III approach.¹⁶
- Oil spill trajectory modeling approach, supported by internationally recognized models, for the prediction of oil fate and relevant environmental impacts for a number of spill simulations (including worst case scenario, such as blowout from an oil well), with the ability to input local current and wind data.
- Strategies for managing Tier I spills from the offshore installation and support vessels (Tiers II and III spill strategies may also be included).
- For Tier I spills, description of the minimum response equipment that must be available on board (minimum equipment for Tiers II and III spills may also be included).
- Arrangements and procedures to mobilize external resources in responding to larger spills and strategies for their deployment.

¹⁵ See for reference: International Petroleum Industry Environmental Conservation Association (IPIECA)/OGP/International Maritime Organization (IMO). 2012. "Sensitivity Mapping for Oil Spill Response." OGP Report Number 477.

¹⁶ See IPIECA Report Series Volume 14: "Guide to Tiered Preparedness and Response." Tier 1 spills are operational in nature occurring at or near an operator's own facilities, as a consequence of its own activities. The individual operator is expected to respond with its own resources. Tier 2 spills are most likely to extend outside the remit of the Tier 1 response area and possibly be larger in size, where additional resources are needed from a variety of potential sources and a broader range of stakeholders may be involved in the response. Tier 3 spills are those that, due to their scale and likelihood to cause major impacts, call for substantial further resources from a range of national and international sources.

- Full list, description, location, and use of on-site and off-site response equipment, and the response times for deployment.
- Strategies for containment and recovery of floating oil, including use (and limitations) of mechanical recovery equipment and chemical dispersants.
- Priorities for response (with input from potentially affected or concerned parties).
- Shoreline cleanup strategies.
- Handling instructions for spilled oil, chemicals, fuels, or other recovered contaminated materials, including their transportation, temporary storage, and disposal.

80. The SRP should clearly define storage and maintenance instructions for Tier I spill response equipment. In addition, each offshore facility/group of facilities should install and maintain a meteo-marine data monitoring station, for planning simulation and response activities.

Loading, Storage, Processing, and Offloading Operations

81. Procedures for loading, storage, processing, and offloading operations, either for consumables (i.e., fuel, drilling fluids, and additives) or for liquid products, should be utilized to minimize spill risks. Pumps, hoses, and valves should be inspected and maintained/replaced as necessary.

82. Floating (Production) Storage and Offloading (FSO/FPSO) vessels and Floating (Liquefaction) Storage Unit (FSU/FLSU) vessels should be subject to inspection and approval by the national/international body, in accordance with International Maritime Organization (IMO) requirements. Double hull vessels are preferred, where available.

83. All offloading activities should be supervised by the designated Mooring Master, who has the authority to prescribe whether “in tandem” or “side-by-side” array should be adopted, according to the conditions of the sea.

84. The conditions and characteristics of the export tankers should be assessed by the Offshore Field Manager prior to commencing offloading operations; only properly registered and well-maintained double-hull vessels should be utilized.

Decommissioning

85. Where more stringent local regulatory requirements do not exist, internationally recognized guidelines and standards issued by IMO and OSPAR¹⁷ should be followed for the decommissioning of offshore facilities.¹⁸

86. IMO standards state that installations or structures of less than 4,000 tonnes, excluding the deck and superstructure, in less than 75 meters of water should be removed entirely at decommissioning, unless an alternative use for the structure has been approved. In addition, installations or structures installed after January 1, 1998 must be designed to be entirely removed. The standards indicate that exceptions will be considered on a case-by-case basis for installations or structures installed before 1998 that cannot be fully removed for demonstrable reasons of technical or financial feasibility, but these facilities must be partially removed to provide a clear water column depth of 55 meters.

87. An OSPAR decision recognizes the entire removal of the facility from offshore locations for re-use, recycling, or final disposal on land as the preferred option for the decommissioning of offshore facilities. Alternative disposal options may be considered if justified on the basis of an alternative options assessment. This assessment 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.

88. A preliminary decommissioning plan for offshore facilities should be developed that considers well abandonment, removal of oil from flowlines, facility removal, and subsea pipeline decommissioning, along with disposal options for all equipment and materials. This plan can be further developed during field operations and fully defined in advance of the end of field life. The plan should include details on the provisions for the implementation of decommissioning activities and arrangements for post-decommissioning monitoring and aftercare.

1.2 Occupational Health and Safety

89. The requirements that follow apply to fixed and floating offshore facilities. Additional requirements related to hazard prevention for floating facilities are provided in Section 1.1, “Loading, Storage, and Offloading Operations.”

¹⁷ OSPAR Convention, <http://www.ospar.org/>

¹⁸ Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone, 1989 (Resolution A.672 (16)), International Maritime Organization (IMO); and the OSPAR Commission Decision 98/3 on the “Disposal of Disused Offshore Installations, and OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic. Ministerial meeting of the OSPAR Commission, Sintra 22-23 July 1998.

90. Occupational health and safety and major hazard issues should be considered as part of a comprehensive risk assessment of the facility through, for example, a combination including a hazard identification study (HAZID), a hazard and operability study (HAZOP), or other risk assessment studies, addressing occupational hazards as well as major accident hazards (including blowout risk). The results should be used for health and safety management planning, in the design of the facility and safe working systems, and in the preparation of safe working procedures. Health and safety management planning should demonstrate that a systematic and structured approach to managing offshore health and safety will be adopted and that controls are in place to reduce risks to as low as reasonably practical. Occupational hazards should be identified and assessed through an Occupational Hazards Assessment report, detailing prevention and mitigation measures (including operational procedures) to be considered. All workers should be made aware of the contents of this document through dedicated induction training.

91. Offshore facilities should be designed to eliminate or reduce the potential for injury or risk of accident. General facility design measures and requirements are provided in the **General EHS Guidelines**. In addition, the following issues should be considered in the design of offshore facilities:

- Environmental conditions at the offshore location (e.g., seismicity, extreme wind and wave events, currents, ice formations).
- Proper selection of materials and development of a monitoring plan to ensure the protection of equipment and structures from corrosion.
- Adequate living accommodations appropriate to outside environmental conditions, plus related policies that consider the physical and mental strain on personnel living on production facilities; space for recreation and social activities and/or a limit to the number of consecutive days permitted on the offshore facility should be considered.
- Limited accommodations in production facilities for staff related to asset operation only.
- Temporary refuges or safe havens located in a protected area at the facility for use by personnel in the event of an emergency.
- A sufficient number of escape routes leading to designated personnel muster points and escape from the facility.
- Handrails, toeboards, and non-slip surfaces on elevated platforms and walkways, stairways, and ramps to prevent person overboard incidents.
- Crane and equipment laydown area positioning to avoid moving loads over critical areas and reducing the impacts from dropped objects. Alternatively, structural protection measures should be provided.

92. In addition to HAZID, occupational health and safety risk management should include communicating to personnel the importance of conducting work activities in a safe and skillful manner, OHS training for staff, and maintaining equipment in a safe condition.

93. A formal Permit to Work (PTW) system should be developed for offshore facilities. The PTW will ensure that all potentially hazardous work is carried out safely and ensures effective authorization of designated work; effective communication of the work to be carried out, including hazards involved; and safe isolation procedures to be followed before commencing work. A lockout/tagout procedure for equipment should be implemented to ensure that all equipment is isolated from energy sources before servicing or removal.

94. Offshore facilities should be equipped, at a minimum, with specialized first-aid providers (industrial pre-hospital care personnel) and the means to provide short-term remote patient care. Depending on the number of personnel present and the complexity of the facility, provision of an on-site medical unit and doctor should be considered. In specific cases, telemedicine facilities may be an alternative option.

95. An alarm system should be installed that can be heard throughout the offshore facility. Alarms for fire, gas leak, and person overboard should be provided.

96. Clear responsibilities for EHS matters should be defined, including identification of a functional role for managing the facility's EHS issues. An EHS responsible officer should be continuously present in the facility, and health and safety inductions should be provided to the entire workforce prior to mobilizing offshore and documented.

97. Guidance for the management of physical hazards common to all industries and specifically relating to hazards from rotating and moving equipment, exposure to noise and vibration, electrical hazards, hot work, working with heavy equipment, working at heights, and the general working environment is provided in the **General EHS Guidelines**. These guidelines also provide guidance on Personal Protective Equipment (PPE) required for the workforce.

98. Additional occupational health and safety issues in offshore oil and gas operations include:

- Fire and explosion prevention and control
- Air quality
- Hazardous materials
- Personnel transfer and vessels
- Well blowouts

- Ship collision
- Dropped objects and material handling issues
- Emergency preparedness and response

Fire and Explosion Prevention and Control

99. Guidance on fire precautions and the prevention and control of fire and explosions is provided in the **General EHS Guidelines**.

100. The most effective ways to prevent fires and explosions in offshore facilities is to prevent the release of flammable material and gas, to implement early detection procedures, and to ensure the interruption of leaks. Potential ignition sources should be kept to a minimum and adequate separation distance between potential ignition sources and flammable materials should be in place. Offshore facilities should be classified into various hazard areas, based on international standards,¹⁹ and in accordance with the likelihood of release of flammable gases and liquids.

101. Appropriate fire and explosion prevention and control measures for offshore facilities should include:

- Provision of passive fire protection throughout the facility to prevent the spread of fire in the event of an incident. Fire protection measures should be designed on the basis of a fire and explosion risk assessment and should include:
 - Provide passive fire protection on load-bearing structures and fire-rated walls, and build fire-rated partitions between rooms.
 - Take into account explosion load in the design of load-bearing structures, or install blast-rated walls.
 - Design items and structures against explosion and evaluate the need for blast walls based on an assessment of likely explosion characteristics.
 - Consider blast panel or explosion venting, and fire and explosion protection should specifically consider wellheads, safe areas, and living areas.
- Ensure the protection of accommodation areas by distance or by fire walls. The ventilation air intakes should prevent smoke and flammable or hazardous gases from entering accommodation areas.

¹⁹ Such as American Petroleum Institute (API) Recommended Practice 500 and 505, International Electrotechnical Commission, or British Standards (BS).

- Locate all fire systems (for example, firewater pumps or control room) in a safe area of the facility, protected from fire by distance or by fire walls. If the system or item is located within a fire area, it should be passive fire-protected or fail-safe.
- Avoid explosive atmospheres in confined spaces by making spaces inert.
- In unmanned facilities, signal the occurrence of gas leaks, fire, or explosion to the remote control center to ensure that appropriate action is taken.
- Conduct a fire impact assessment to determine the type and extent of fire detection and protection required for an offshore facility. A combination of automatic and manual fire alarm systems are typically provided on offshore facilities. Active fire protection systems should be installed on offshore facilities and should be strategically located to enable rapid and effective response. A combination of active fire suppression mechanisms can be used, depending on the type of fire and the fire impact assessment (for example, fixed foam system, fixed fire water system, CO₂ extinguishing system, water mist system, gaseous extinguishing system, fixed dry chemical system, fixed wet chemical system, fire water monitors, live hose reels, and portable fire extinguishing equipment). Halon-based fire systems should be avoided. Firewater pumps should be available and designed to deliver water at an appropriate rate. Regular checks and maintenance of firefighting equipment are essential.
- Provide fire safety training and response as part of workforce health and safety induction/training, with advanced fire safety training provided to a designated firefighting team.

Air Quality

102. Guidance for the maintenance of air quality in the workplace, along with required air quality levels, is provided in the **General EHS Guidelines**.

103. Due to the risk of gas releases caused by leaks or emergency events, adequate ventilation in closed or partially closed spaces is required at offshore oil and gas facilities. Air intakes should be installed to ventilate facility safe areas and areas that should be operable during emergency situations. If necessary, the means to detect dangerous gas concentrations in the intakes, as well as automatic shut-down in the event of dangerous gas levels should be installed. A dangerous concentration of flammable gas can be considered to be a fraction (approximately 20 percent) of the Lower Explosive Limit of the substance.

104. The facilities should be equipped with a reliable system for gas detection that allows the source of release to be isolated and the inventory of gas that can be released to be reduced. Blowdown of pressure equipment should be initiated to reduce system pressure and consequently reduce the release flow rate. Gas detection devices should also be used to authorize entry and operations into enclosed spaces.

105. Wherever hydrogen sulfide (H₂S) gas may accumulate, monitors should be installed and set to activate warning signals whenever detected concentrations of H₂S exceed 7 milligrams per cubic meter (mg/m³). Personnel should also be provided with personal H₂S detectors and response training in the event of a leak. A self-contained breathing apparatus should be provided and the apparatus designed and conveniently located to enable personnel to safely interrupt tasks and reach a temporary refuge or safe haven.

Hazardous Materials

106. The design of the offshore facilities should reduce exposure of personnel to chemical substances, fuels, and products containing hazardous substances. Use of substances and products classified as highly toxic, carcinogenic, allergenic, mutagenic, teratogenic, or strongly corrosive should be identified and the products replaced by less hazardous alternatives, wherever possible. For each chemical used, a Material Safety Data Sheet (MSDS) should be readily available on the facility. A general hierarchical approach to the prevention of impacts from chemical hazards is provided in the **General EHS Guidelines**.

107. A procedure for the control and management of radioactive sources used offshore should be prepared, along with a designated shielded container for storage when the source is not in use. The container should be locked in a secure store that is exclusively used for this purpose.

108. In locations where NORM may precipitate as scale or sludge in process piping and production vessels, facilities and process equipment should be monitored for the presence of NORM at least every five years, or whenever equipment is to be taken out of service for maintenance. NORM can have adverse health effects through external irradiation or internal exposure (if NORM is taken into the body via inhalation, ingestion, or absorption). Where NORM is detected, the expected annual doses and the probability and magnitude of potential exposures should be assessed and a workforce monitoring and management program, appropriate to the magnitude and nature of the risks, should be developed and implemented (e.g., source control, exposure monitoring, worker education and safe operating practices, including appropriate PPE). Procedures should determine the classification of the area where NORM is present and the level of supervision and control required.

109. The operator should determine whether to leave the NORM in-situ, or to remove it for disposal, as described in Section 1.1 of these Guidelines.

Personnel Transfer and Vessels

110. Personnel transfer to and from offshore facilities typically occurs by helicopter or boat. Safety procedures for helicopter and vessel transport of personnel are required. Passengers should systematically receive a safety briefing and safety equipment as part of helicopter or vessel transport.

111. Equipment used for personnel transportation should be certified and the transportation crew qualified according to applicable national and international regulations. In the event of helicopter transport, the helicopter should be certified according to International Civil Aviation Organization (ICAO) rules. In the event of marine transport, the vessel should be class approved.

112. Helicopter decks (helideck) onboard offshore facilities should follow the requirements of the ICAO. Facilities for mooring boats during the transfer of personnel should consider adverse sea conditions to protect the boat and the facility structure from heavy impacts.

113. If personnel are transferred from the boat to the facility by crane, only cranes, cables, and baskets certified for personnel transfer should be used.

114. Support vessels should have the relevant permits and certifications to comply with IMO requirements. A Vessel Safety Management System should be implemented.

Well Blowouts

115. A blowout (i.e., loss of well control) can be caused by the uncontrolled flow of reservoir fluids into the wellbore and may result in an uncontrolled release of formation fluids into the environment.

116. Blowout prevention measures should focus on maintaining wellbore hydrostatic pressure by effectively estimating formation fluid pressures and the strength of subsurface formations. This can be achieved with techniques such as proper pre-well planning; drilling fluid logging; or using sufficient hydrostatic head of weighted drilling fluid or completion fluid to balance the pressures in the wellbore. Well integrity testing (e.g., negative pressure test, cement bond log) should be performed, with the type of test and frequency defined by the operator, based on the actual operation characteristics and through a risk-based process to confirm that the proposed testing is adequate to ensure well integrity.

117. A Blow Out Preventer (BOP) system should be installed that can be closed rapidly in the event of an uncontrolled influx of formation fluids and that allows the well to be circulated to safety by venting the gas at surface and routing oil so that it may be contained. The BOP should be tested at installation and at regular intervals (at least every 14 days), via partial or complete shutdown, based on availability considerations related to the specific application. BOP testing should be conducted by an independent

specialist, particularly for critical wells (e.g., deepwater, high pressure, or high temperature wells). Facility personnel should conduct well control drills at regular intervals and key personnel should attend well control courses periodically.

118. The BOP design should be in general compliance with international standards. It is recommended that, at a minimum, subsea BOP systems consist of one annular preventer, two blind-shear ram preventers, and two pipe ram preventers, and that they be equipped with choke and kill lines and failsafe choke and kill close valves. The BOP preventers should be able to close the BOP for the maximum drill pipe string foreseen for the drilling operations. BOP shall operate (failsafe) in the event of a loss of control signal from the surface. Subsea BOP should allow closure of pipe rams and blind shear rams by Remotely Operated Vehicle (ROV) intervention.²⁰

119. Contingency planning should be prepared for well operations and should include identification of provisions for well capping in the event of uncontrolled blowout (providing indication of the tools, equipment, and intervention time required), and identification of spill recovery measures.²¹

120. A dedicated blowout risk analysis and emergency plan should be prepared, detailing the measures in place to prevent blowout, the provisions for well control in a blowout scenario (including capping tools and oil spill recovery means), and indicating the time necessary for the intervention. The risk analysis should include failure mode and effect analysis of the technical systems in place to control a blowout, as well as reliability analysis of the systems. Blowout risk analysis is mandatory in the case of deepwater wells, where emergency intervention is more difficult and intervention times higher than is typical, and for high-pressure or high-temperature wells.

Ship Collision

121. To avoid collisions with third-party and support vessels, offshore facilities should be equipped with navigational aids that meet national and international requirements. Navigational aids include radar and lights on facility structures and, where appropriate, on support vessels. A 500-meter radius facility exclusion zone, at a minimum, should be implemented around permanent offshore facilities. The facility should monitor and communicate with vessels approaching the facility to reduce the risk of vessel collision.

²⁰ Blow Out Preventer (BOP) requirements and safety considerations on well safety are provided in American Bureau of Shipping (ABS) 2012; API RP53 1997; OGP 2011a; NORSOK 2004; US Environmental Protection Agency (EPA) CFR 30, Part 250, Subpart D, 2013.

²¹ See OGP 2011b and OGP 2011c.

122. The relevant maritime, port, or shipping authority should be notified of all permanent offshore facilities, as well as exclusion zones and routine shipping routes to be used by project-related vessels. Permanent facility locations should be marked on nautical charts. The maritime authorities should be notified of the schedule and location of activities when there will be a significant increase in vessel movement, such as during facility installation, rig movements, and seismic surveys.

123. A subsea pipeline corridor safety zone (typically, 1,000 meters wide) should be established to define anchoring exclusion zones and provide protection for fishing gear. In shallower waters with high shipping activity, consideration should be given to burying the pipeline below the seabed.

Emergency Preparedness and Response

124. Guidance relating to emergency preparedness and response, including emergency resources, is provided in the **General EHS Guidelines**. Offshore facilities should establish and maintain a high level of emergency preparedness to ensure that the response to incidents is effective and without delay. Potential worst-case accidents should be identified by risk assessment and appropriate preparedness requirements designed. An emergency response team should be established for the offshore facility. Such a team should be trained to respond to potential emergencies, rescue injured persons, and perform emergency actions. The team should coordinate actions with other agencies and organizations that may be involved in emergency response.

125. Personnel should be provided with adequate and sufficient emergency response equipment that is appropriately located for the evacuation of the facility. Lifeboats should be available in sufficient numbers for the entire workforce. These lifeboats should be enclosed, fire-resistant crafts with trained lifeboat operators. Ice vehicles are required for the evacuation from facilities in frozen waters. Sufficient lifejackets, lifebuoys, and survival suits should also be provided.

126. Evacuation by helicopter should not be considered as the primary means of escape.

127. Exercises in emergency preparedness should be practiced at a frequency commensurate with the project risk. At a minimum, the following practice schedule should be implemented:

- Quarterly drills without equipment deployment.
- Evacuation drills and training for egress from the platform under different weather conditions and at varying times of day.
- Annual mock drills with equipment deployment.
- Regular training, updated as needed and based on continuous evaluation.

128. An emergency response plan should be prepared, based on the identification of potential emergency scenarios, which contains the following measures, at a minimum:

- A description of the response organization (structure, roles, responsibilities, and decision makers).
- Description of response procedures (details of response equipment and location, procedures, training requirements, duties, etc.).
- Descriptions and procedures for alarm and communications systems.
- Precautionary measures for securing the well(s).
- Relief well arrangements, including description of equipment, consumables, and support systems to be utilized.
- Description of on-site first-aid supplies and available backup medical support.
- Description of other emergency facilities, such as emergency fueling sites.
- Description of survival equipment and gear, alternate accommodation facilities, and emergency power sources.
- Procedures for person overboard.
- Evacuation procedures.
- Emergency Medical Evacuation (MEDEVAC) procedures for injured or ill personnel.
- Policies defining measures for limiting or stopping events, and conditions for the termination of action.

1.3 Community Health and Safety

129. Impacts to community health and safety from typical offshore oil and gas facility operations relate to potential interaction with other sea users, primarily shipping companies and fishermen. Impacts may include accidents, loss of containment, and blowouts. A comprehensive assessment addressing potential hazards to local communities and to the environment is required. Based on the findings of the assessment, adequate measures to avoid or control the hazards should be taken and should be factored into emergency planning.

130. Activities such as offshore drilling and construction, pipeline installation, seismic operations, and decommissioning may result in temporary impacts to other users of the sea. Permanent installations and structures, including production and drilling facilities and subsea pipelines, have a potential long-term impact, at least until the end of the life of the field. Notification of the location of offshore facilities (including subsea hazards) and timing of offshore activities should be provided to local and regional maritime authorities, including fishery groups. The position of fixed facilities and safety exclusion zones should be marked on nautical charts. Clear instructions regarding access limitations to exclusion zones should be communicated to other sea users. Subsea pipeline routes should be regularly monitored for the presence of pipeline spans and identified spans should be repaired in a timely manner.

131. In areas where significant impacts to fishermen are anticipated, a fisheries liaison officer should be appointed to provide a direct link with the fishing community. Arrangements for the management of potential community or amenity impacts resulting from shoreline impacts caused by oil, chemical, or fuel spills are to be included in the spill response plans.

Security

132. Unauthorized access to offshore facilities should be avoided by means of gates located in the stairs from the boat landings to the deck level. Means for detecting intrusion (for example, closed-circuit television) may be considered, allowing the control room to verify the conditions of the facility. Additional active and passive security measures should be defined on the basis of a site-specific risk assessment.

133. A facility standby vessel should be considered for all offshore facilities (in case of multi-platform developments, platforms do not have to have their own dedicated standby vessels). These vessels should support security operations, monitoring third-party vessels entering the exclusion zone, manage supply vessel approach to the facility, and support operations during emergency situations.

2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

134. Table 1 presents effluent guidelines for offshore oil and gas development. Guideline values for process effluents in this sector are indicative of good international industry practice, as reflected in the relevant standards of countries with recognized regulatory frameworks. The guidelines are assumed to be achievable under normal operating conditions in appropriately designed and operated facilities through the application of pollution prevention and control techniques discussed in the preceding sections of this document.

135. The effluent guidelines are primarily applicable to discharges in off-shore locations (e.g., greater than 12 nautical miles from shore). Discharge water quality to near-shore waters should be established on a case-specific basis, taking into account the environmental sensitivities and assimilative capacity of receiving waters.

136. Combustion source emissions guidelines associated with steam- and power-generation activities from sources with a capacity equal to or lower than 50 MWth are addressed in the **General EHS Guidelines**, with larger power source emissions addressed in the **EHS Guidelines for Thermal Power**. Guidance on ambient considerations based on the total load of emissions is provided in the **General EHS Guidelines**.

Environmental Monitoring

137. Environmental monitoring programs for this sector should be implemented as required to address all activities that have been identified to have potentially significant impacts on the environment, during normal operations and upset conditions. Environmental monitoring activities should be based on direct or indirect indicators of emissions, effluents, and resource use applicable to the particular project.

138. Monitoring frequency should be sufficient to provide representative data for the parameter being monitored. Monitoring should be conducted by trained individuals following monitoring and record-keeping procedures and using properly calibrated and maintained equipment. Monitoring data should be analyzed and reviewed at regular intervals and compared with the operating standards, so that any necessary corrective actions can be taken. Additional guidance on applicable sampling and analytical methods for emissions and effluents is provided in the **General EHS Guidelines**.

Table 1. Effluent levels from Offshore Oil and Gas Development

Parameter	Guideline
Drilling Fluids and Cuttings – NADF	<p>1) NADF: re-inject or ship-to-shore, no discharge to sea</p> <p>2) Drilled cuttings: re-inject or ship-to-shore, no discharge to sea except:</p> <ul style="list-style-type: none"> For new facilities: Organic Phase Drilling Fluid (OPF^a) concentration lower than 1% by weight on dry cuttings For existing facilities: Residual Non Aqueous Phase Drilling Fluid^b (NAF) 6.9% (C₁₆-C₁₈ internal olefins, and C₈-C₁₆) or 9.4% (fatty acid/2-ethylhexyl esters) on wet cuttings Hg: max 1 mg/kg dry weight in stock barite Cd: max 3 mg/kg dry weight in stock barite Discharge via a caisson (at least 15 m below surface is recommended whenever applicable; in any case, a good dispersion of the solids on the seabed should be demonstrated)
Drilling Fluids and Cuttings – WBDF	<p>1) WBDF: re-inject or ship-to-shore, no discharge to sea except:</p> <ul style="list-style-type: none"> In compliance with 96 hr. LC-50 of SPP-3% vol. toxicity test first for drilling fluids or alternatively testing based on standard toxicity assessment species^c (preferably site-specific species) <p>2) WBDF, fluids and cuttings: re-inject or ship-to-shore, no discharge to sea except:</p> <ul style="list-style-type: none"> Hg: 1 mg/kg dry weight in stock barite Cd: 3 mg/kg dry weight in stock barite Maximum chloride concentration must be less than four times the ambient concentration of fresh or brackish receiving water Discharge via a caisson at least 15 m below sea surface
Produced Water	Reinject. Discharge to sea is allowed if oil and grease content does not exceed 42 mg/l daily maximum; 29 mg/L monthly average ^d
Flow-Back Water	Reinject or reuse. Discharge to sea is allowed if oil and grease content does not exceed 42 mg/L daily maximum; 29 mg/L monthly average. An environmental risk assessment, to determine the maximum site-specific allowable concentrations should be conducted for all other chemicals
Completion and Well Work-Over Fluids	<p>Ship-to-shore or reinject. No discharge to sea except:</p> <ul style="list-style-type: none"> Oil and grease content does not exceed 42 mg/L daily maximum; 29 mg/L monthly average Neutralize to attain a pH of 5 or more In compliance with 96 hr. LC-50 of SPP-3% vol. toxicity test first for drilling fluids or alternatively testing based on standard toxicity assessment species^c (preferably site-specific species)
Produced Sand	Ship-to-shore or reinject. No discharge to sea except when oil concentration lower than 1% by weight on dry sand
Hydrotest Water	<ul style="list-style-type: none"> Send to shore for treatment and disposal Discharge offshore following environmental risk analysis, careful selection of chemicals Reduce use of chemicals
Cooling Water	The effluent should result in a temperature increase of no more than 3° C at edge of the zone where initial mixing and dilution take place. Where the zone is not defined, use 100 m from point of discharge.
Desalination Brine	Mix with other discharge waste streams, if feasible ^e
Sewage	Compliance with MARPOL 73/78 ^e
Food Waste	Compliance with MARPOL 73/78 ^e
Storage Displacement Water	Compliance with MARPOL 73/78 ^e
Bilgewater	Compliance with MARPOL 73/78 ^e
Deck Drainage (non-hazardous and hazardous drains)	Compliance with MARPOL 73/78 ^e

Notes:
^aAs defined by OSPAR Decision 2000/3.
^bAs defined in U.S. Environmental Protection Agency (EPA). 2013. "Code of Federal Regulations (CFR)." Title 40: Protection of Environment. Part 435. Oil and Gas Extraction Point Source Category; Subpart A—Offshore Subcategory—Specialized Definitions. Washington, D.C.: EPA.
^c96-hr LC-50: Concentration in parts per million (ppm) or percent of the Suspended Particulate Phase (SPP) from sample that is lethal to 50 percent of the test organism exposed to that concentration for a continuous period of 96 hours.
^dConsistent with U.S. EPA CFR 40 Part 435, 2013; OSPAR "Recommendation for the Management of Produced Water from Offshore Installations" 2011; OGP 2005.
^eIn nearshore waters, carefully select discharge location based on environmental sensitivities and assimilative capacity of receiving waters.

2.2 Occupational Health and Safety

139. Key Performance Indicators should be adopted to monitor operations and anticipate potential health and safety issues. Both lagging indicators (measuring retrospectively the performances of the facilities) and leading indicators (indicating situations that could result in future health and safety issues) should be defined for the facility. These indicators should consider both technical systems and operational/management issues.

Occupational Health and Safety Guidelines

140. Occupational health and safety performance should be evaluated against internationally published exposure guidelines, of which examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEIs®), published by American Conference of Governmental Industrial Hygienists (ACGIH);²² the Pocket Guide to Chemical Hazards, published by the United States National Institute for Occupational Health and Safety (NIOSH);²³ Permissible Exposure Limits (PELs), published by the Occupational Safety and Health Administration of the United States (OSHA);²⁴ Indicative Occupational Exposure Limit Values, published by European Union member states;²⁵ or other similar sources. Particular attention should be given to the occupational exposure guidelines for hydrogen sulfide (H₂S).

141. Guidance on occupational exposure to ionizing radiation and its monitoring when NORM is present is provided in the **General EHS Guidelines** and other internationally recognized sources.²⁶

Accident and Fatality Rates

142. Projects should try to reduce the number of accidents among project workers (whether directly employed or subcontracted) to a rate of zero, especially accidents that could result in lost work time, different levels of disability, or fatalities. Facility rates may be benchmarked against the performance of facilities in this sector in developed countries through consultation with published sources (e.g., U.S. Bureau of Labor Statistics and U.K. Health and Safety Executive).²⁷

²² <http://www.acgih.org/TLV/> and <http://www.acgih.org/store/>.

²³ <http://www.cdc.gov/niosh/npg/>.

²⁴ http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9992.

²⁵ http://europe.osha.eu.int/good_practice/risks/ds/oel/.

²⁶ ICRP 2007.

²⁷ <http://www.bls.gov/iif/> and <http://www.hse.gov.uk/statistics/index.htm>.

Occupational Health and Safety Monitoring

143. The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals²⁸ as part of an occupational health and safety monitoring program. Facilities should also maintain a record of occupational accidents and diseases, as well as dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the **General EHS Guidelines**.

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²⁸ Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.

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Annex A: General Description of Industry Activities

144. The primary products of the offshore oil and gas industry are crude oil, natural gas liquids, and natural gas. Crude oil consists of a mixture of hydrocarbons having varying molecular weights and properties. Natural gas can be produced from oil wells, or wells can be drilled with natural gas as the primary objective. Methane is the predominant component of natural gas, but ethane, propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed, and these are often separated and processed as natural gas liquids.

Exploration Activities

Seismic surveys

145. Seismic surveys are conducted to pinpoint potential hydrocarbon reserves in geological formations deep below the seafloor. Seismic technology uses the reflection of sound waves to identify subsurface formations. In modern marine seismic surveys, as many as 16 “streamers” (cables containing the hydrophones used to detect the sound reflected from the subsurface) are towed behind the seismic vessel, at a depth of 5 to 10 meters (m). Each cable can be as long as 8 to 10 kilometers (km). In addition to the hydrophone array, the vessel tows seismic source arrays comprising a number of airguns, which discharge sound bursts of between 200–250 decibels (dB) downward. The sound bursts, repeated on average every 6 to 10 seconds, are reflected off deep geological formations and recorded by the hydrophone array.

Exploration drilling

146. Exploratory drilling activities offshore follow the analysis of seismic data to verify and quantify the amount and extent of oil and gas resources from potentially productive geological formations. If oil or gas is encountered, then additional development drilling may be undertaken.

147. There are various types of offshore drilling rigs, including:

- *Jack-up rigs*: Suitable for shallower water up to around 100 m and transported to location, either under their own propulsion or towed by tugs. Once there, electric or hydraulic jacks lower three or four legs to the seafloor to support the drilling platform above water.
- *Semi-submersible rigs*: Suitable for deep waters and transported to location, either under their own propulsion or towed by tugs. The hull is partially submerged and the rig held in place by a series of anchors.

- *Submersible rigs*: Limited to shallow waters and towed onto location. Consisting of two hulls: an upper hull, or platform, and lower hull that is filled with water and submerged to the seafloor.
- *Drilling barges as floating platforms*: Suitable for shallow waters, estuarine areas, lakes, marshes, swamps, and rivers. Not suitable for open or deep water. Towed onto location.
- *Drillships*: Designed for drilling in deep water locations. Drilling takes place from a drilling platform and derrick positioned in the middle of the deck, from which drill stems are lowered through a hole in the hull (moonhole).

148. Once on location, a series of well sections of decreasing diameter are drilled from the rig. A drill bit, attached to the drill string suspended from the rig's derrick, is rotated in the well. Drill collars are attached to add weight and drilling fluids are circulated through the drill string and pumped through the drill bit. The fluid has a number of functions. It imparts hydraulic force that assists the drill bit cutting action, and it cools the bit, removes rock cuttings from the wellbore, and protects the well against formation pressures. When each well section has been drilled, steel casing is run into the hole and cemented into place to prevent well collapse, fluid slips, and anomalous pressures in the annulus. Casing is also typically installed after decommissioning.

149. When the reservoir is reached, the well may be completed and tested by running a production liner and equipment to flow the hydrocarbons to the surface in an effort to establish reservoir properties in a test separator.

Field Development

150. Field development may occur after exploration (and additional appraisal well drilling) has located and confirmed economically recoverable reserves of hydrocarbons. In many cases, this will involve the installation of an offshore drilling and production platform that is self-sufficient in terms of energy and water needs for the workforce and for drilling wells and processing hydrocarbons ready for export.

151. There are many types of offshore platforms, including:

- *Fixed platforms*: Used in water depths of up to around 500 m and consisting of steel or concrete legs (jacket), secured directly to the seabed by steel piles that support a steel deck. Drilling equipment, production facilities, and accommodation are typically housed on the deck.
- *Compliant towers*: Used in water depths ranging from around 500 m up to 1,000 m and consisting of a narrow, flexible tower on a piled foundation supporting a conventional deck.

- *Tension leg platforms*: Used in water depths of up to about 2,000 m and consisting of a floating facility moored to the seabed and fixed in place by anchors. Mini tension leg platforms (Seastars) are used in water depths of between 200 m and 1,000 m.
- *Jack-up platforms*: Used in shallower water up to around 100m and transported to location, where the legs are lowered by hydraulic jacks into position to support the deck.
- *Spar platforms*: Used in water depths of between 500 m and 1,700 m and consisting of a cylindrical hull supporting a floating platform.
- *Floating production systems*: Ships equipped with processing facilities and moored on location with a series of anchors or by global positioning system devices. Usually based on a converted oil tanker, the main types of floating production systems are Floating, Production, Storage, and Offloading (FPSO) systems; Floating, Storage, and Offloading (FSO) systems; and Floating Storage Units (FSU).

152. Production platforms will provide facilities for the separation of formation fluids into oil, gas, and water. Depending on the project, the platform may only be used for production, as drilling can be conducted from a separate drilling rig brought alongside. Some platforms are only used to bring the hydrocarbons to surface and directly export them for processing, while some gas platforms may be unmanned during routine production operations. Typically, multiple wells are drilled from the platform location using directional drilling techniques. In some cases, where field extremities not reachable by directional drilling from the fixed location or where small reservoirs exist, subsea production units are installed on the seabed following drilling and the produced hydrocarbons are tied into a nearby platform facility by a system of risers.

153. Following development drilling and well completion in readiness for the flow of formation fluids, a “christmas tree,” which allows the control of flow to the surface, is placed onto the well head. The oil and/or gas are produced by separation of the formation fluid mixture into oil and gas and water, or gas and condensates at the platform. Oil is exported from the platform by either pumping into a subsea pipeline to shore, or to a floating storage unit offshore, or directly to a tanker. Typically, gas is exported through a pipeline.

154. Most fields produce in a predictable pattern, called a decline curve, where production increases relatively rapidly to a peak and then follows a long, slow decline. Water or gas injection is often used to maintain reservoir pressure and enhance production. In other cases, Enhanced Oil Recovery (EOR) techniques—such as the injection of steam, nitrogen, carbon dioxide, or surfactants—may be used to enhance recovery.

155. Operators may periodically perform workovers to clean out the wellbore, allowing oil or gas to move easily to the surface. Other measures to increase production include fracturing and treating the bottom of the wellbore with acid to create better pathways allowing oil and gas to move to the surface.

Hydraulic fracturing

156. Hydraulic fracturing of hydrocarbon-containing rocks is a technique for maximizing commercial gas and some oil production from tight reservoirs. The technique is mainly applied onshore, with some development in offshore fields. Typically, hydraulic fracturing involves injecting, through the wellhead, a batch of some 12,000–20,000 m³ of water, mixed with sand and fractional amounts of chemical additives. The injection pressure is a function of the well depth and the rock characteristics. The average composition of the injected mixture is 90 to 95 percent water, 4.5 to 9.5 percent sand, and 0.5 percent chemical additives. Additives are comprised of inorganic or organic acids, gelling agents, friction reducers, and surfactants. Biocides, scales inhibitors, corrosion inhibitors, and cross-linking agents may also present in low concentrations.

Coal Bed Methane

157. Coal Bed Methane (CBM) is more frequently utilized onshore. Limited cases present offshore may include hydraulic fracturing (see above) to improve production performance. CBM wells are characterized by high water production, which requires proper treatment systems (a low concentration of oil and grease, but a possible presence of heavy metals and hydrophilic compounds).

Storage and Offloading

158. The oily phase of produced fluids from a well/group of wells can be either pumped to shore for further stabilization using flowlines, or treated by offshore production facilities (e.g., treatment platforms, FPSOs), to create a product suitable for transportation by tanker carriers.

159. The oil produced and treated offshore is temporarily stored in offshore storage facilities before being transferred to the export tanker carriers. Storage can occur in underwater cylinders, anchored to the structure of gravity platforms, or, more frequently, oil is stored in a permanently (or semi-permanently) moored vessel of substantial capacity (150,000–250,000 tons of displacement). From there, the oil produced is transferred to the export tanker carriers at regular intervals, according to the field production and storage capacity of the facility.

160. Offloading operations (i.e., the transfer from the field storage system to the export vessels) may include oil spill risks that should be assessed and minimized. Risks for floating production storage and offloading vessels can be related to the simultaneous operations (SIMOPS) of oil treatment and product

storage. The marine conditions present additional risks; for instance, in typhoon areas, potential collisions between the FSO/FPSO and the export carriers. Ruptures in the offloading of large-diameter hoses are also a consideration.

Decommissioning and Abandonment

161. The decommissioning of offshore facilities occurs when the reservoir is depleted or the production of hydrocarbons from that reservoir becomes unprofitable. Parts of the offshore facility, such as platforms, are treated to remove contaminants and are usually removed, while other production components are rendered safe and left in place.

162. Wells are plugged and abandoned to prevent fluid migration within the wellbore, which could contaminate the surface environment. The downhole equipment is removed and the perforated parts of the wellbore are cleaned of sediment, scale, and other debris. The wellbore is then plugged to prevent the inflow of fluids. Fluids with an appropriate density are placed between the plugs to maintain adequate pressure. During this process, the plugs are tested to verify their correct placement and integrity. Finally, the casing is cut off below the surface and capped.