

# 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).<sup>1</sup> 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](http://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.

## 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.

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<sup>1</sup> 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.

This document is organized in the following manner:

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## 1. 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**. The **EHS Guidelines for Crude Oil and Petroleum Product Terminals** include information relevant to land- and shore-based petroleum storage terminals receiving and dispatching bulk shipments of crude oil and refined products from pipelines, tankers, railcars, and trucks for subsequent commercial distribution.

### 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

#### 1.1.1 Air Emissions

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

9. One of the most important components of these emission sources is carbon dioxide (CO<sub>2</sub>). Principal pollutants include nitrogen oxides (NO<sub>x</sub>), sulfur oxides (SO<sub>x</sub>), carbon monoxide (CO), and particulates. Additional pollutants can include hydrogen sulfide (H<sub>2</sub>S); volatile organic compounds (VOCs); methane and ethane; benzene, ethyl benzene, toluene, and xylenes (BTEX); glycols; and polycyclic aromatic hydrocarbons (PAHs). In some cases, mercaptans and mercury may be present, which require specific care. Firefighting and refrigeration systems may contain halons and chlorofluorocarbons, which are Ozone Depleting Substances (ODS).<sup>2</sup>

10. Aggregate greenhouse gas (GHG) emissions from all facilities and offshore support activities should be quantified annually in accordance with internationally recognized methodologies.

11. All reasonable attempts should be made to implement appropriate methods for controlling and reducing fugitive emissions in the design, operation, and maintenance of offshore facilities and 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, reciprocating engines or boilers, used for heat or power generation or to drive machinery such as compressors or pumps can be the most significant source of air emissions from offshore facilities. During equipment selection, air emission specifications should be taken into account, as should the use of very low sulfur content fuels and/or natural gas.

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, helping to ensure that gas and other hydrocarbons are safely disposed of in the event of an emergency, a power or equipment failure, or other facility upset condition. Risk assessment processes (e.g., hazard and operability study (HAZOP), hazard identification study (HAZID), etc.) to estimate the implications of situations of this type should be used in such facilities.

<sup>2</sup> See also Oil and Gas UK, "About the Industry," last updated November 2009, [http://www.oilandgasuk.co.uk/knowledgecentre/atmospheric\\_emissions.cfm](http://www.oilandgasuk.co.uk/knowledgecentre/atmospheric_emissions.cfm).

16. Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard<sup>3</sup> (part of the Global Gas Flaring Reduction Public-Private Partnership) 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 feasible alternatives for the gas's use should be evaluated to the maximum extent possible and integrated into production design.<sup>4</sup>

18. Alternative options may include gas utilization for on-site energy needs, gas injection for reservoir pressure maintenance, enhanced oil recovery using gas lift, or export of the gas to a neighboring facility or to market. An assessment of alternatives should be made and 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 or 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, and stream 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, vapor recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots.
- Minimize risk of pilot blowout 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 overpressure events and avoid or reduce flaring situations.
- 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).

<sup>3</sup> See World Bank (2004).

<sup>4</sup> Ibid.

- 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 facility upset conditions arise, excess gas should not be vented but rather should be sent to an efficient flare gas system. Emergency venting may be necessary under specific field conditions where a flare gas system is not available or when flaring of the gas stream is not possible, such as when there is 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 facility 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, with the safety of handling volatile hydrocarbons considered, 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 sole 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 (collected gaseous stream that is directly released to the atmosphere without burning in flare), leaking tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, open tanks for Non-Aqueous Drilling Fluids (NADF) (generating diffuse emissions), 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 the equipment's safety and suitability requirements as well

as its capacity to reduce gas leaks and fugitive emissions. Additionally, all collected gaseous streams should be burned in high efficiency flare(s), and leak detection and repair programs should be implemented.

### **1.1.2 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, with the exception of Coal Bed Methane (CBM) reservoirs, from which a large amount of produced water is initially 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 operation's largest waste products, by volume, and therefore requires management by offshore operators.

29. Produced water contains a complex mixture of inorganic (dissolved salts, trace concentrations of certain metals, suspended particles), organic (suspended and dissolved hydrocarbons, traces of fatty acids and other organic compounds), and in some cases residual trace concentrations of chemical additives (for example, scale and corrosion inhibitors, hydrate inhibitors), which 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 facility and production design. These alternatives may include injection along with seawater for reservoir pressure maintenance, injection into a suitable offshore disposal well,<sup>5</sup> or export to shore with produced hydrocarbons for reuse or disposal after proper treatment.

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 options is technically or financially feasible and disposal to sea is the only feasible option, 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.

<sup>5</sup> See also as technical reference, U.S. Bureau of Safety and Environmental Enforcement (US BSEE) (2009).

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—or 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 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.<sup>6</sup> In particular, the use and dispersion of Kinetic Hydrate Inhibitors (KHI) should be assessed to avoid possible accumulation of poorly degraded residuals.

### ***Flowback Water***

37. The water that flows back from the well to the surface after hydraulic fracturing, is generally referred to as *flowback water*. If hydraulic fracturing is planned or forms part of the project,<sup>7</sup> as in the case of shale gas projects or CBM, all environmental aspects—including fracture propagation and related possible fugitive emissions, fracturing fluid management, and the fate and management of flowback water—should be evaluated.<sup>8</sup> Flowback water requires considerations separate from or in addition to those bearing on produced water. Flowback water characteristics depend on the type of fluid (water or diesel) and chemicals injected to induce rock fracturing and can also be present in large quantities. Flowback water can thus constitute one of the most important environmental management issues for hydraulic fracturing operations.

38. Feasible alternatives for the management and disposal of flowback water should be evaluated and integrated into operational design. Alternatives may include temporary storage in sealed tanks prior to injection into a suitable offshore disposal well, temporary storage for reuse in further hydraulic fracturing operations, or export 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—

<sup>6</sup> Adequate tools and approaches should be adopted with the intent of assessing the hazards and risks deriving from the use of any chemicals in the hydrocarbons production. Chemical Hazard Assessment and Risk Management is one such approach.

<sup>7</sup> See International Association of Oil and Gas Producers (IOGP) (2013c); and IOGP and International Petroleum Industry Environmental Conservation Association (IPIECA) (2013).

<sup>8</sup> Any possible social concerns (for example, related to induced microseismicity) should also be assessed.

including their toxicity, bioavailability, and bioaccumulation potential—should be conducted to assess the maximum site-specific allowable concentrations.

### ***Hydrostatic Testing Water***

39. 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.
- 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.

40. 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,<sup>9</sup> environmental risk, and monitoring. Hydrotest water disposal into shallow coastal waters and sensitive ecosystems should be avoided.

### ***Cooling Water***

41. 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, to avoid entrainment and impingement of marine flora and fauna.

42. 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***

43. Operators should consider mixing desalination brine from the potable water system with cooling water or other effluent streams. If mixing with other discharge streams is not feasible, the discharge

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<sup>9</sup> See Oslo-Paris Convention for the Protection of the Marine Environment of the North-East Atlantic Commission (OSPAR) (2010a).

location should be carefully selected with respect to potential environmental impacts. In particular, in the case of coastal and/or brackish water, the reverse osmosis process should be designed to allow reduction of the salinity of the rejected effluent.

### **Other Waste Waters**

44. 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 International Convention for the Prevention of Pollution from Ships (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.
- *Ballast and storage displacement water*:<sup>10</sup> 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 nonprocess areas (open drains). All process areas should be banded 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 banded 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.

### **1.1.3 Waste Management**

45. Typical nonhazardous and hazardous wastes<sup>11</sup> 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.

46. At a minimum, these waste materials should be segregated offshore into nonhazardous and hazardous wastes and shipped to shore for reuse, 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 wastes at all times.

<sup>10</sup> U.S. Environmental Protection Agency (US EPA) (2012a).

<sup>11</sup> As defined by local legislation or international conventions.

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

48. Additional waste streams that can be 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***

49. 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 and weight, generated during oil and gas drilling activities.

50. Though various drilling fluids are available, they can generally be categorized into the following:

- 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.

51. 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 drilling mud liquid phase is not good practice for offshore drilling programs and should be avoided.

52. 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 viscosifier. Drilling fluids can also contain a variety of other components to enhance their performance and/or to address reservoir compatibility requirements.

53. 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 reuse 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 applied only when the chemical content is low and water-based drilling mud is used.

54. 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.

55. 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.

56. 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.

57. 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.

58. 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**.

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

- 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 drilling 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.

60. 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.

61. WBDF and treated drilled cuttings discharge should be made via a caisson submerged at an appropriate depth to ensure suitable dispersion of the effluent (i.e., a dispersion study demonstrates that the relevant impact is acceptable).

### ***Produced Sand***

62. Sand produced 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.

63. 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. Direct 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.

64. 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***

65. Completion and well work-over fluids (including intervention fluids and service fluids) can include solid material, residual drilling fluids, weighted brines or acids, hydrocarbons, methanol and glycols, and other types of performance-enhancing additives. 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.

66. Feasible disposal options should be considered, including the following:

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

67. 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)***

68. Depending on the field reservoir characteristics, NORM may be present in the produced fluids.<sup>12</sup> NORM may precipitate as scale or sludge in process piping and production vessels in which the concentration of NORM can be higher than in the fluid.<sup>13</sup> Where NORM is present, or NORM precipitation and/or accumulation conditions are known or expected to exist, a NORM management program should be developed to ensure worker safety and the use of appropriate handling and waste management procedures.

69. 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 an engineered and properly operated landfill within 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.

70. NORM-containing sludge, scale, or equipment should be treated, processed, isolated, and/or disposed of according to good international industry practices,<sup>14</sup> so that potential future human exposure to the treated waste will be within internationally accepted limits.<sup>15</sup>

#### **1.1.4 Hazardous Materials Management**

71. Hazardous materials (including some chemicals) are sometimes used in offshore oil and gas operations. General guidance for the management of hazardous materials is provided in the **General EHS Guidelines**.

72. The following additional principles should be followed for the management of hazardous materials offshore:

- Use chemical hazard assessment and risk management techniques to evaluate chemicals and their effects.
- Select only those chemicals that have been previously tested for environmental hazards.
- Select chemicals based on the OSPAR<sup>16</sup> Harmonised Offshore Chemical Notification Format or similar internationally recognized system.
- Select chemicals with the least hazard and lowest potential environmental and health risks, whenever possible.
- Avoid chemicals suspected to cause taint or known endocrine disruptors.

<sup>12</sup> NORM is 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 (ICRP) (2007).

<sup>13</sup> See IOGP (2008a).

<sup>14</sup> For more on the management of NORM residues, see International Atomic Energy Agency (IAEA) (2013).

<sup>15</sup> ICRP (2007).

<sup>16</sup> The name comes from the Oslo-Paris Convention for the Protection of the Marine Environment of the North-East Atlantic, <http://www.ospar.org/>.

- For new offshore oil and gas facilities, Ozone Depleting Substances (ODS) should not be used;<sup>17</sup> opportunities to change-out ODS-containing devices in existing offshore oil and gas facilities as part of on-going equipment maintenance and replacement programs should be evaluated.
- Avoid chemicals known to contain heavy metals of concern, in anything other than trace quantities.

### 1.1.5 Noise

73. Offshore oil and gas development activities generating noise include seismic operations, drilling and production activities, offshore and nearshore structural installation (especially pile driving), construction and decommissioning activities, and marine traffic. Noise from offshore activities (especially from seismic operations) may temporarily affect fish and marine mammals to varying degrees depending on the strength of the noise, local species present, and their distance from the source.<sup>18</sup>

74. 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 the following:

- 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 using experienced observers<sup>19</sup> before the onset of sound-creating activities that have the potential to produce adverse effects, and continue monitoring throughout the seismic program or construction.
- 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.

<sup>17</sup> As defined by the 1989 Montreal Protocol on Substances that Deplete the Ozone Layer, [http://ozone.unep.org/new\\_site/en/montreal\\_protocol.php](http://ozone.unep.org/new_site/en/montreal_protocol.php).

<sup>18</sup> See Joint Nature Conservation Committee (JNCC) (2010); International Association of Geophysical Contractors (IAGC) and IOGP (2011); and further references in section 3.0.

<sup>19</sup> See also IAGC (2011); and JNCC (2010).

- 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.
- For pile driving, use vibratory hammers, air bubble curtains (confined or unconfined), temporary noise attenuation piles, air filled fabric barriers, and isolated piles or coffer dams, where practical.

### 1.1.6 Spills

75. 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 the following tasks:

- Conduct a spill risk assessment for offshore facilities and support vessels.<sup>20</sup>
- Design process, utility, and drilling systems to reduce the risk of major uncontained spills.<sup>21</sup>
- Install a Blowout Prevention System (BOP) during the drilling phase and valves during commissioning for production—including subsea shutdown valves, if required—for the reduction of risk and 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, Supervisory Control and Data Acquisition systems,<sup>22</sup> pressure sensors, shut-in valves, and pump-off systems, including at normally unattended installations and unmanned facilities to ensure rapid detection of loss of containment.
- An Emergency Shutdown System should be in place in all facilities, able to initiate automatic shutdown actions to bring the offshore facility to a safe condition; it should be activated in case of any significant release.
- Implement adequate personnel training and field exercises in oil spill prevention, containment, and response.
- Ensure that spill response and containment equipment, routinely inspected, maintained, and operationally exercised and tested, is deployed or available as necessary for response. Document and report all spills, as well as near misses. Following a spill or near miss, carry out a root cause investigation and undertake corrective actions to prevent recurrence.

<sup>20</sup> IOGP and IPIECA (2013).

<sup>21</sup> See also National Research Council (NRC) (2014).

<sup>22</sup> These may be used in oil and gas and other industrial facilities to assist in the monitoring and control of plants and equipment.

### 1.1.7 Spill Response Planning

76. A Spill Response Plan (SRP) should be prepared, and the capability to implement the plan should be in place. A preliminary SRP is recommended, commencing at the project development phase and based on the initial project design, and it should include community consultation and feedback.

77. The SRP should address potential oil, chemical, and fuel spills from offshore facilities and support vessel—including tankers—and pipeline ruptures and leaks. The SRP should include all appropriate oil spill response tools and options in order to allow responders, in cooperation with the appropriate authorities, to develop response strategies that mitigate environmental impacts to the greatest extent practicable. The plan should also include the following:

- A description of operations, site conditions, product(s) characteristics, expected seasonal current and wind data, sea conditions and water depth, and logistical support arrangements.
- A spill risk assessment, defining expected frequency and size of spills from potential release sources, including an assessment of foreseeable scenarios.<sup>23</sup>
- 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 training requirements, responsibilities, authority, roles, and contact details.
- Sensitivity mapping of marine and coastal environmental habitats, associated wildlife, and socioeconomic resources that could be affected by spills generated by offshore oil and gas development and production activities.<sup>24</sup>
- Cooperative measures with government agencies, if appropriate, and relevant notification process and procedures.

78. The SRP should also include the following:

- Clear demarcation of spill severity, according to the size of a spill, using a clearly defined Tier 1, Tier 2, and Tier 3 approach.<sup>25</sup>
- Oil spill trajectory modeling approach, supported by internationally recognized models (in accordance with the relevant regulatory jurisdiction prescriptions, if any), 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 1, Tier 2, and Tier 3 spills from the offshore installation and support vessels.

<sup>23</sup> See also IOGP (2013c), as a reference in case of fracking; and IOGP and IPIECA (2013).

<sup>24</sup> See, for reference, IPIECA, International Maritime Organization (IMO), and IOGP (2012).

<sup>25</sup> See IPIECA (2008). 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.

- For Tier 1 spills, description of the minimum response equipment that must be available on board (minimum equipment for Tier 2 and Tier 3 spills may also be included).
- Arrangements and procedures to mobilize external resources in responding to larger spills and strategies for their deployment.
- 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.<sup>26</sup>
- Priorities for response (with input from potentially affected or concerned parties).
- Methods to maximize recovery and response capabilities (e.g., remote sensing, aerial observation and command and control, infrared, RADAR, etc.).
- Shoreline protection and cleanup strategies.
- Measures to rehabilitate wildlife such as seabirds, mammals, and turtles.
- Handling instructions for recovered spilled oil, chemicals, fuels, or other recovered contaminated materials, including their transportation, temporary storage, and disposal.
- Measures to be taken to protect health and safety of oil spill personnel.

79. The SRP should clearly define storage and maintenance instructions for Tier 1 spill response equipment and relevant routine inspection, testing, and exercises. In addition, each offshore facility and group of facilities should install and maintain a meteorological and marine data monitoring station for planning simulation and response activities.

### **1.1.8 Loading, Storage, Processing, and Offloading Operations**

80. 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 or replaced as necessary.

81. Floating (Production) Storage and Offloading (FSO/FPSO) vessels and Floating (Liquefaction) Storage Unit (FSU/FLSU) vessels should be subject to inspection and certification by an appropriate national or international body, in accordance with International Maritime Organization (IMO) requirements. Double hull vessels are preferred, whenever available.<sup>27</sup>

82. All offloading activities should be supervised by the designated Mooring Master,<sup>28</sup> who has the authority to prescribe whether an “in tandem” or “side-by-side” array should be adopted, according to the conditions of the sea.

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<sup>26</sup> NRC (2005).

<sup>27</sup> IMO (2005–2006).

<sup>28</sup> The qualified person in charge of, among other things, assessing and guaranteeing that the vessel's design and condition are up to par for the operation, reporting to the Offshore Field Manager for decisions, advising masters of both FSO/FPSO and export tanker, supervising the vessels' approach, maneuvering into final position, mooring and positioning of the lightering hoses, monitoring the transfer of oil into the lightering vessel to ensure that no leaks or spills occur, overseeing the connection of hoses, and maneuvering of vessels upon completion of the operation.

83. The conditions and characteristics of the export tankers should be assessed by the Mooring Master and reported to the Offshore Field Manager<sup>29</sup> prior to commencing offloading operations; only properly registered and well-maintained double-hull vessels should be utilized.

### **1.1.9 Decommissioning**

84. Where more stringent local regulatory requirements do not exist, internationally recognized guidelines and standards issued by IMO and OSPAR<sup>30</sup> should be followed for the decommissioning of offshore facilities.<sup>31</sup>

85. 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.

86. An OSPAR decision recognizes the entire removal of the facility from offshore locations for reuse, 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.

87. A preliminary decommissioning plan for offshore facilities should be developed that considers well abandonment, removal of hydrocarbons 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**

88. The requirements that follow apply to fixed and floating offshore drilling, production and accommodation facilities. Additional requirements related to hazard prevention for floating facilities are provided in section 1.1, paragraph “Loading, Storage, Processing, and Offloading Operations.”

89. Occupational health and safety and major hazard issues should be considered as part of a comprehensive risk assessment of an offshore facility through, for example, a combination including a HAZID study, HAZOP study, or other risk assessment studies that encompass occupational hazards as

<sup>29</sup> The Offshore Field Manager is the company's officer in charge of, among other things, inspecting the facility and field, writing up reports, and notifying Management of all activities.

<sup>30</sup> See the OSPAR Convention, <http://www.ospar.org/>.

<sup>31</sup> See IMO (1989); OSPAR (1998); and the OSPAR Convention.

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 Management Plan, detailing prevention and mitigation measures (including operational procedures) to be considered. All workers should be made aware of the contents of this document through induction training.

90. Offshore facilities should be designed to eliminate or reduce the potential for injury or risk of an accident.<sup>32</sup> 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 or drilling facilities; space for recreation and social activities and/or consideration of a limit to the number of consecutive days permitted on the offshore facility.
- Limited accommodations in production and drilling 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 nonslip 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.)

91. Occupational health and safety (OHS) risk management should be based on application of risk assessment principles to identify hazards, risks, and controls (e.g., HAZID) and 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.

92. A formal Permit to Work (PTW) system should be developed for offshore facilities. The PTW system 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 and/or tagout procedure for

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<sup>32</sup> National Academy of Engineering (NAE) and National Research Council of the National Academies (NRCNA) (2011); Transportation Research Board of the National Academies (TRBNA) (2012).

equipment should be implemented to ensure that all equipment is isolated from energy sources before servicing or removal.

93. Offshore facilities should be equipped, at a minimum, with specialized first-aid providers (industrial prehospital 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 a doctor may need to be considered. In specific cases, telemedicine facilities may be an alternative option.

94. An alarm system should be installed that can be heard throughout the offshore facility. Alarms for fire, H<sub>2</sub>S and hydrocarbon gas leak, and person overboard should be provided.

95. Clear responsibilities for EHS matters should be defined, including identification of a functional role for managing the facility's EHS issues. An officer responsible for EHS 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.

96. 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, confined space entry, 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) for workers.

97. Additional occupational health and safety issues in offshore oil and gas operations include the following:

- 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

### **1.2.1 Fire and Explosion Prevention and Control**

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

99. 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 distances between potential ignition sources and flammable materials should be in place. Any venting or flaring shall be remote from potential ignition sources; a gas dispersion analysis from vent should document the

adequacy of vent position. Offshore facilities should be classified into various hazard areas, based on international standards,<sup>33</sup> and in accordance with the likelihood of release of flammable gases and liquids.

100. Appropriate fire and explosion prevention and control measures for offshore facilities should include the following:

- Provide 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 consideration of the fire hazard.<sup>34</sup> The fire protection measures should
  - provide passive fire protection on load-bearing structures and fire-rated walls and build fire-rated partitions between rooms;
  - take into account explosion loads in the design of load-bearing structures or install blast-rated walls;
  - design items and structures to protect against explosion and evaluate the need for blast walls based on an assessment of likely explosion characteristics; and
  - 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 shall be designed to prevent smoke and flammable or hazardous gases from entering accommodation areas.
- Locate 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 in nature.
- Avoid explosive atmospheres in confined spaces by making spaces inert or by including adequate ventilation.
- 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). For new offshore oil and gas developments, 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 and training, with advanced fire safety training provided to a designated firefighting team.

<sup>33</sup> Such as American Petroleum Institute (API) (1997c, 1997d) Recommended Practices 500 and 505; International Electrotechnical Commission; or British Standards.

<sup>34</sup> API (2013b).

## 1.2.2 Air Quality

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

102. Due to the risk of gas releases caused by leaks or emergency events, adequate ventilation in closed or partially closed spaces is required on offshore oil and gas facilities. Air intakes should be installed to ventilate facility safe areas and areas that need to be operable during emergency situations. If necessary, the means to detect gas in the intakes and alarm or automatic shut-down systems should be installed.<sup>35</sup>

103. 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.

104. Wherever hydrogen sulfide (H<sub>2</sub>S) gas may accumulate, monitors should be installed and set to activate warning signals whenever detected concentrations of H<sub>2</sub>S exceed 7 milligrams per cubic meter (mg/m<sup>3</sup>). Personnel should also be provided with personal H<sub>2</sub>S 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.

## 1.2.3 Hazardous Materials

105. The design of the offshore facilities should reduce the 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 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**.

106. 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 used exclusively for this purpose.

107. In locations where NORM may precipitate as scale or sludge in process piping and production vessels, facilities and/or process equipment that have been taken out of service for maintenance, replacement, or decommissioning should be monitored for NORM. 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

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<sup>35</sup> Typically, alarm levels for flammable gas are set no higher than approximately 25 percent of the Lower Explosive Limit of the substance. It is common practice to use several detectors and select higher set points for automatic shutdown and dampener closure.

(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.

108. The operator should determine whether to leave the NORM in-situ, or to remove it for disposal, as described in [Section 1.1 of this Guideline](#).

#### **1.2.4 Personnel Transfer and Vessels**

109. 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.

110. 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.

111. Helicopter decks (helidecks) onboard offshore facilities should follow the requirements of the ICAO. Facilities and equipment for station keeping of vessels during the transfer of personnel should consider adverse sea conditions to protect the boat and the facility structure from heavy impacts.

112. If personnel are transferred from a boat to an offshore facility by crane, only cranes, cables, and baskets certified for personnel transfer should be used.

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

#### **1.2.5 Well Blowouts**

114. 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 and gases into the environment. Blowout can occur during drilling and work-over phases (where it is of particular concern) or during production phases.

115. 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 prewell planning and technical reviews (i.e., audits of the well control equipment and personnel competency, independent review of well design and control procedures), drilling fluid logging, and 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 as informed by a risk-based process to confirm that the proposed testing approach is adequate to ensure well integrity and control.<sup>36</sup>

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<sup>36</sup> See IOGP (2011a).

116. A 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 system should be tested at installation and at regular intervals (at least every 14 days) via partial or complete shutdown and based on availability considerations related to the specific application. The BOP system should be pressure tested at installation, after the disconnection or repair of any pressure containment seal in the BOP system, and at regular intervals, as operations allow. Surface BOP stacks should be tested to their rated working pressure during an initial pressure test, and then to the maximum anticipated surface pressure during subsequent tests. Subsea BOP stacks should initially be tested to the rated working pressure of the ram preventers or the wellhead system, whichever is lower, and then during subsequent tests to the maximum anticipated wellhead pressure for the current well program. Facility personnel should conduct well-control drills at regular intervals, and key personnel should attend well control courses periodically; well control training and drills should be documented. BOP testing should be conducted by an independent specialist, particularly for critical wells (e.g., deep water, 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; well control training and drills should be documented.

117. The BOP system design, maintenance, and repair 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 systems shall operate (failsafe) in the event of a loss of control signal from the surface. At a minimum, subsea BOP systems should allow closure of one set of pipe rams and all blind shearing type rams by Remotely Operated Vehicle (ROV) intervention, should automatic systems fail.<sup>37</sup>

118. Contingency plans 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.<sup>38</sup>

119. A dedicated blowout risk analysis and emergency plan should be prepared, detailing the measures in place to prevent a 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 a failure mode and effect analysis as well as a reliability analysis of the technical systems in place to control a blowout, as well as reliability analysis of the systems. The risk analysis should include an assessment of conditions under which gas hydrates are formed,<sup>39</sup> the impact of hydrate formation on well safety and control during the containment of a kick and on well control equipment operations, and the relevant mitigations. Blowout risk analysis is mandatory in the case of deep water wells, where

<sup>37</sup> See API (2012), Standard 53, section 6 (Surface BOP) and section 7 (Subsea BOP), for testing frequencies, pressures and documentation expectations. API Standard 53 also includes guidelines for testing auxiliary well-control equipment, including choke/kill lines, annular diverter, choke manifold, etc. for both surface and subsea wells. BOP requirements and safety considerations on well safety are provided in American Bureau of Shipping (ABS) (2012); API (2012) Standard 53; IOGP (2011a); NORSOK (2004); and US BSEE (2013b).

<sup>38</sup> See IOGP (2011b, 2011c).

<sup>39</sup> Methane gas hydrate formation is a potential drilling hazard for drilling operations in shallow waters in cold environments and in water depths greater than 500 meters.

emergency intervention is more difficult and intervention times higher than is typical, and for high-pressure, high-temperature wells.

### 1.2.6 Ship Collision

120. 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 safety zone, at a minimum, should be implemented around offshore facilities. The facility should monitor and communicate with vessels approaching the facility to reduce the risk of vessel collision.

121. The relevant maritime, port, or shipping authority should be notified of all permanent offshore facilities, as well as safety zones and routine shipping routes to be used by project-related vessels. Permanent facility locations should be marked on nautical charts. 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.

122. 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.

### 1.2.7 Dropped Objects and Material Handling Issues

123. A dedicated dropped objects analysis should be prepared, assessing the risk of loads falling from handling devices and impacting critical areas of the facility or subsea pipelines in the vicinity of the facility. This analysis will identify the need for measures to prevent damage to critical items or structures and to risers and sealines. A material handling study, to identify handling devices and procedures to avoid impacts and stresses and injuries to personnel, should be developed.

### 1.2.8 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 facilities; such a team should be trained to respond to 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, including medical emergency equipment and evacuation devices. These devices shall be 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-capable vehicles should be in place for the evacuation from facilities in frozen waters. Sufficient lifejackets, lifebuoys, and survival suits should also be provided.

126. Helicopters should not be considered as the primary means of evacuation.

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

- Drills without equipment deployment as a minimum on quarterly basis
- 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 a well or wells
- Relief well arrangements, including a 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 actions

### **1.3 Community Health and Safety**

129. Impacts to community health and safety from typical offshore oil and gas facility operations relate primarily 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 a field. Notification of the location of offshore facilities (including subsea hazards) and the 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 shall be included in the spill response plans. These should be effectively communicated to the fishing community.

### **1.3.1 Security**

132. Access to offshore facilities by unauthorized parties 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 offshore facilities (in case of multiphase developments, platforms do not have to have their own dedicated standby vessels). These vessels should support security operations, monitor third-party vessels entering the exclusion zone, manage supply vessel approach to the facility, and support operations during emergency situations.

## **2. PERFORMANCE INDICATORS MONITORING**

### **2.1 Environment**

#### **2.1.1 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 applicable primarily to discharges in offshore locations. 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.

**TABLE 1. EFFLUENT LEVELS FROM OFFSHORE OIL AND GAS DEVELOPMENT**

| PARAMETER                                   | GUIDELINE  |
|---|--|
| <b>Drilling Fluids and Cuttings – NADF</b>  | 1) NADF: Reinject or ship-to-shore, no discharge to sea<br>2) Drilled cuttings: Reinject or ship-to-shore, no discharge to sea except: <ul style="list-style-type: none"> <li>• Facilities located beyond 3 miles (4.8 km) from shore;</li> <li>• For new facilities:<sup>a</sup> Organic Phase Drilling Fluid<sup>b</sup> concentration lower than 1% by weight on dry cuttings;</li> <li>• For existing facilities<sup>c</sup>: Use of Group III non-aqueous base fluids and treatment in cutting dryers. Maximum residual Non Aqueous Phase Drilling Fluid<sup>d</sup> (NAF) 6.9% (C<sub>16</sub>-C<sub>18</sub> internal olefins) or 9.4% (C<sub>12</sub>-C<sub>14</sub> ester or C<sub>8</sub> esters) on wet cuttings;</li> <li>• Hg: max 1 mg/kg dry weight in stock barite</li> <li>• Cd: max 3 mg/kg dry weight in stock barite</li> <li>• 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)</li> </ul> |
| <b>Drilling Fluids and Cuttings – WBDF</b>  | 1) WBDF: Reinject or ship-to-shore, no discharge to sea except: <ul style="list-style-type: none"> <li>• In compliance with 96 hr. LC-50 of Suspended Particulate Phase (SPP)-3% vol. toxicity test first for drilling fluids or alternatively testing based on standard toxicity assessment species<sup>e</sup> (preferably site-specific species)</li> </ul> 2) WBDF cuttings: Reinject or ship-to-shore, no discharge to sea except: <ul style="list-style-type: none"> <li>• Facilities located beyond 3 miles (4.8 km) from shore;</li> <li>• Hg: 1 mg/kg dry weight in stock barite</li> <li>• Cd: 3 mg/kg dry weight in stock barite</li> <li>• Maximum chloride concentration must be less than four times the ambient concentration of fresh or brackish receiving water</li> <li>• Discharge via a caisson (at least 15 m below sea surface is recommended whenever applicable; in any case, a good dispersion of the solids on the seabed should be demonstrated)</li> </ul>  |
| <b>Produced Water</b>                       | Reinject. Discharge to sea is allowed if oil and grease content does not exceed 42 mg/l daily maximum; 29 mg/L monthly average   |
| <b>Flow-Back Water</b>                      | 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  |
| <b>Completion and Well Work-Over Fluids</b> | Ship-to-shore or reinject. No discharge to sea except: <ul style="list-style-type: none"> <li>• Oil and grease content does not exceed 42 mg/L daily maximum; 29 mg/L monthly average</li> <li>• Neutralize to attain a pH of 5 or more</li> <li>• In compliance with 96 hr. LC-50 of SPP-3% vol. toxicity test first for drilling fluids<sup>e</sup> or alternatively testing based on standard toxicity assessment species (preferably site-specific species)</li> </ul>   |
| <b>Produced Sand</b>                        | Ship-to-shore or reinject: No discharge to sea except when oil concentration lower than 1% by weight on dry sand   |
| <b>Hydrotest Water</b>                      | <ul style="list-style-type: none"> <li>• Send to shore for treatment and disposal.</li> <li>• Discharge offshore following environmental risk analysis, careful selection of chemicals<sup>9</sup></li> <li>• Reduce use of chemicals.</li> </ul>  |

**TABLE 1. EFFLUENT LEVELS FROM OFFSHORE OIL AND GAS DEVELOPMENT**

| PARAMETER   | GUIDELINE  |
|---|--|
| <b>Cooling Water</b>  | 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. |
| <b>Desalination Brine</b>                                   | Mix with other discharge waste streams, if feasible.   |
| <b>Sewage</b>   | Compliance with MARPOL 73/78 <sup>h</sup>  |
| <b>Food Waste</b>   | Compliance with MARPOL 73/78 <sup>h</sup>  |
| <b>Storage Displacement Water</b>                           | Compliance with MARPOL 73/78 <sup>h</sup>  |
| <b>Bilgewater</b>   | Compliance with MARPOL 73/78 <sup>h</sup>  |
| <b>Deck Drainage</b><br>(nonhazardous and hazardous drains) | Compliance with MARPOL 73/78 <sup>h</sup>  |

<sup>a</sup> New facilities include offshore drilling rigs which have been newly designed or structurally modified for the project.

<sup>b</sup> As defined by OSPAR (2000) Decision 2000/3.

<sup>c</sup> Applicable to existing offshore drilling rigs deployed for development well drilling programs. Applicable to exploratory well drilling programs. Technically and financially feasible techniques, including installation of thermo-mechanical cutting cleaning systems, to meet the guidelines for new facilities should be considered for implementation, in relation to the number of wells (including producers and injectors) included in development drilling programs, and/or to potential impacts on critical habitats.

<sup>d</sup> As defined in US EPA (2013a).

<sup>e</sup> 96-hr LC-50: Concentration in parts per million or percent of the SPP from sample that is lethal to 50 percent of the test organism exposed to that concentration for a continuous period of 96 hours. See also: <http://www.epa.gov/nmr/ld/std/qsar/TEST-user-guide-v41.pdf>.

<sup>f</sup> Consistent with US EPA (2013a); OSPAR (2011); IOGP (2005).

<sup>g</sup> In accordance with OSPAR (2010a) "Recommendation 2010/4 on a Harmonised Pre-screening Scheme for Offshore Chemicals" or other applicable process

<sup>h</sup> In nearshore waters, carefully select discharge location based on 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 **Thermal Power EHS Guidelines**. Guidance on ambient considerations based on the total load of emissions is provided in the **General EHS Guidelines**.

137. All ships, platforms and drilling rigs should be compliant with the Regulations for the Prevention of Air Pollution from Ships set forth in MARPOL Annex VI,<sup>40</sup> where applicable. The provisions of Annex VI are not applicable to emissions directly arising from the exploration, exploitation and associated offshore oil and gas processing.

### **2.1.2 Environmental Monitoring**

138. 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.

139. 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**.

## **2.2 Occupational Health and Safety**

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

### **2.2.1 Occupational Health and Safety Guidelines**

141. Occupational health and safety performance should be evaluated against internationally published exposure guidelines. Examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEI®), published by American Conference of Governmental Industrial Hygienists (ACGIH);<sup>41</sup> Pocket Guide to Chemical Hazards, published by the United States National Institute for Occupational Health and Safety (NIOSH);<sup>42</sup> Permissible Exposure Limits (PELs),

<sup>40</sup> International Convention for the Prevention of Pollution from Ships (known universally as MARPOL), revised annex VI adopted in October 2008, which entered into force on July 1, 2010. See <http://www.imo.org/OurWork/Environment/PollutionPrevention/>.

<sup>41</sup> <http://www.acgih.org/TLV/> and <http://www.acgih.org/store/>.

<sup>42</sup> <http://www.cdc.gov/niosh/npg/>.

published by the Occupational Safety and Health Administration of the United States (OSHA);<sup>43</sup> Health Leading Performance Indicators, published by IPIECA and IOGP);<sup>44</sup> Indicative Occupational Exposure Limit Values, published by European Union member states;<sup>45</sup> or other similar sources. Particular attention should be given to the occupational exposure guidelines for hydrogen sulfide (H<sub>2</sub>S).

142. 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.<sup>46</sup>

## 2.2.2 Accident and Fatality Rates

143. 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 UK Health and Safety Executive).<sup>47</sup>

## 2.2.3 Occupational Health and Safety Monitoring

144. The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals as part of an occupational health and safety monitoring program.<sup>48</sup> 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**.

<sup>43</sup> [http://www.osha.gov/pls/oshaweb/owadisp.show\\_document?p\\_table=STANDARDS&p\\_id=9992](http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=9992).

<sup>44</sup> <http://www.ogp.org.uk/publications/health-committee/health-performance-indicators-data/health-performance-indicators-2012-data/>.

<sup>45</sup> [http://europe.osha.eu.int/good\\_practice/risks/ds/oel/](http://europe.osha.eu.int/good_practice/risks/ds/oel/).

<sup>46</sup> ICRP (2007).

<sup>47</sup> <http://www.bls.gov/iif/> and <http://www.hse.gov.uk/statistics/index.htm>.

<sup>48</sup> Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, Certified Safety Professionals, or their equivalents.

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## **ANNEX A. GENERAL DESCRIPTION OF INDUSTRY ACTIVITIES**

145. 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 can also be 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.

### **A.1 Exploration Activities**

#### ***Seismic Surveys***

146. 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. Each cable can be as long as 8 to 10 kilometers. In addition to the hydrophone array, the vessel tows seismic source arrays comprising a number of airguns, which discharge sound bursts of 200–250 decibels 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***

147. 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.

148. There are various types of offshore drilling rigs, including the following:

- *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.
- *Semisubmersible 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; it may have dynamic positioning assistance.
- *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). Drillships are usually kept “on station” by means of dynamic positioning technology.

149. 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. If hydrocarbons are discovered in quantities that allow them to be economically produced, a wellhead and a "Christmas tree" are installed to allow for future production. Otherwise, the well is plugged (with cement) and abandoned. When the targeted hydrocarbon-bearing formation 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.

## **A.2 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 the following:

- *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. Minitension 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 100 m 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. Sometimes 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.

152. Production platforms will provide facilities for the separation of formation fluids into oil, gas, and water. Depending on the project, the platform may be used only for production, as drilling can be conducted from a separate drilling rig brought alongside. Some platforms are used only 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 wellhead. 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 pumping it into a subsea pipeline to shore, 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*, in which 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 techniques—such as the injection of steam, nitrogen, carbon dioxide, or surfactants—may be used to enhance recovery.

155. Operators may periodically perform work-overs 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.

### **A.3 Hydraulic Fracturing**

156. Hydraulic fracturing of hydrocarbon-containing subsurface strata is a technique for realizing and maximizing commercial gas and oil production from low permeability reservoirs. This technique is applicable to onshore and offshore locations. Though recently becoming controversial, fracking has been used on a smaller scale for many years to improve the flow from conventional oil and gas wells. Today, hydraulic fracturing is largely applied onshore, with some applicability in offshore fields. Differences exist between the technical arrangements adopted offshore with respect to onshore; however, it typically involves injecting, through the wellhead, some thousands of cubic meters of water mixed with sand and fractional amounts of chemical additives; different fluids can also be used, such as hydrocarbons or gases (N<sub>2</sub>, CO<sub>2</sub>) and foams. 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 comprise inorganic or organic acids, gelling agents, friction reducers, and surfactants. Biocides, scale inhibitors, corrosion inhibitors, and cross-linking agents may also present in low concentrations. In case of high permeability formations, as it may happen in some offshore reservoirs, the fracturing fluid will usually be more viscous and have a higher sand concentration than similar fluids used onshore. Multistage hydraulic fracturing is now a commonly utilized approach. In some cases, when the target hydrocarbon-producing geological unit comprises loose sand, a specific technique is applied, referred as “frack pack,” combining fracking with gravel (sand) packing. In this case, more sand is pumped into the well in order to create a layer of proppant, which reduces or eliminates the production of sand from the well.<sup>49</sup>

<sup>49</sup> See also API (2013a).

#### **A.4 Coalbed Methane**

157. Coalbed methane (CBM) is more frequently developed 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).

#### **A.5 Storage and Offloading**

158. The liquid hydrocarbon phase of produced fluids from a well or group of wells can either be pumped to shore for processing 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 tankers. Storage can occur in underwater cylinders, anchored to the structure of gravity platforms, or, more frequently, oil is stored in a permanently (or semipermanently) moored vessel of substantial capacity (150,000–250,000 tons of displacement). From there, the stabilized oil is transferred to the export tanker carriers at regular intervals, according to the field production profile and storage capacity of the facility.

160. Offloading operations (i.e., the transfer from the offshore storage system to the export tankers) 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 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. Preventing ruptures in the large-diameter export tanker loading hoses also warrants a high degree of attention.

#### **A.6 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 themselves 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.