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

Introduction

1. The Environmental, Health, and Safety (EHS) Guidelines are technical reference documents with general and industry-specific examples of Good International Industry Practice (GIIP)\(^1\). When one or more members of the World Bank Group are involved in a project, these EHS Guidelines are applied as required by their respective policies and standards. These industry sector EHS guidelines are designed to be used together with the General EHS Guidelines document, which provides guidance to users on common EHS issues potentially applicable to all industry sectors. For complex projects, use of multiple industry-sector guidelines may be necessary. A complete list of industry-sector guidelines can be found at: [www.ifc.org/ehsguidelines](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 is 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 Onshore Oil and Gas Development include information relevant to seismic exploration, exploration and production drilling, development and production activities, transport activities including

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\(^1\) Defined as the exercise of professional skill, diligence, prudence, and foresight that would be reasonably expected from skilled and experienced professionals engaged in the same type of undertaking under the same or similar circumstances globally. The circumstances that skilled and experienced professionals may find when evaluating the range of pollution prevention and control techniques available to a project may include, but are not limited to, varying levels of environmental degradation and environmental assimilative capacity as well as varying levels of financial and technical feasibility.
flowlines and pipelines, other facilities including pump stations, metering stations, pigging stations, compressor stations and storage facilities, ancillary and support operations, and decommissioning. For onshore oil and gas facilities located near the coast (e.g., coastal terminals marine supply bases, loading/offloading terminals), additional guidance is provided in the EHS Guidelines for Ports, Harbors, and Terminals. Potential onshore impacts that may result from offshore oil and gas activities are addressed by the EHS Guidelines for Offshore Oil and Gas Development. This document is organized in the following manner:

1. Industry-Specific Impacts and Management
   1.1 Environment
   1.2 Occupational Health and Safety
   1.3 Community Health and Safety
2. Performance Indicators Monitoring
   2.1 Environment
   2.2 Occupational Health and Safety
3. References

Annex A. General Description of Industry Activities

1.0 Industry-Specific Impacts and Management

6. This section provides a summary of EHS issues associated with onshore 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 onshore oil and gas development projects include the following:
   - Air emissions;
   - Wastewater discharges;
   - Solid and liquid waste management;
   - Noise generation;
   - Terrestrial impacts and project footprint;
• Impacts on subsoil and aquifers;
• Spills;
• Spill Response Planning; and
• Energy efficiency and resource conservation.

Air Emissions

8. The main sources of air emissions (continuous or intermittent) from onshore activities include: combustion sources for power and heat generation (e.g., boilers, turbines); reciprocating and other engines of onshore facilities, including support equipment (e.g., trucks, cranes, dozers); emissions resulting from flaring and venting of hydrocarbons; intermittent emissions (e.g., well-testing emissions, safety flaring, engine exhaust) and fugitive/diffuse emissions.

9. One of the most important components of these emission sources in terms of mass is carbon dioxide (CO₂), as it derives from any combustion of hydrocarbons and may also be contained in natural gas produced from the reservoir. Water vapor (H₂O) is also present in the reservoir, and is generated during hydrocarbon combustion. Principal pollutants, also deriving from combustion, include nitrogen oxides (NOₓ), sulfur oxides (SOₓ), and carbon monoxide (CO). Particulates, also originating from combustion, can affect human health and vegetation. Additional pollutants can include hydrogen sulfide (H₂S); volatile organic compounds (VOCs); methane and ethane; benzene, ethyl benzene, toluene, and xylenes (BTEX); glycols; and polycyclic aromatic hydrocarbons (PAHs). 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).

10. Aggregate greenhouse gas (GHG) emissions from all facilities and onshore 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 onshore 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.

12. Air quality impacts should be estimated by the use of baseline air quality assessments and atmospheric dispersion models to establish potential ground level ambient air concentrations during facility design and operations planning as described in the General EHS Guidelines. These studies should ensure that no adverse impacts to human health and the environment result.

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2 Natural gas can sometimes comprise a significant proportion of Nitrogen (N₂); when present, it is not considered an environmental pollutant.
3 See also Oil and Gas UK, About the Industry, last updated November 2009, [http://oilandgasuk.co.uk/atmospheric-emissions.cfm](http://oilandgasuk.co.uk/atmospheric-emissions.cfm)
Exhaust Gases

13. Exhaust gas emissions produced by the combustion of gas or liquid fuels in turbines, reciprocating engines or boilers, for power and heat generation, or for water injection or oil and gas export, can be a significant source of air emissions from onshore 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.

14. 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.

15. For emissions deriving from combustion sources with a capacity of up to 3 MW that are typically used for power generation in drilling rigs, drilling contracting companies should be requested to provide generators able to comply with the local air emissions standards or, as a minimum, to retrofit the exhausts of the power units with catalytic converters.

Venting and Flaring

16. Associated gas brought to the surface with crude oil during oil production is sometimes disposed of at onshore facilities by venting or flaring. This practice is now widely recognized to be a significant waste of a valuable non-renewable resource as well as a significant source of GHG emissions.

17. However, flaring and venting are important safety measures on onshore 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 identifications study (HAZID), etc.) to estimate the implications of situations of this type should be used in such facilities.

18. Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the Global Gas Flaring Reduction Public-Private Partnership (GGFR program)) should be adopted when considering venting and flaring options for onshore activities. The standard provides guidance on how to eliminate or achieve reductions in the flaring and venting of natural gas.

19. Continuous venting of associated gas is not good international industry practice and should be avoided. The associated gas stream should be routed to an efficient flare system, although continuous flaring of gas should be

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4 See World Bank (2004).
5 Ibid.
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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.6

20. 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. 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.

21. For existing facilities, cost-effective options to reduce flaring 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.

22. 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 maximum 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 of 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);
- Situate flare at a safe distance8 from local communities and accommodation units/manned buildings;
- Implement burner maintenance and replacement programs to ensure continuous maximum flare efficiency; and

6 Ibid.
8 Safe distance is to be evaluated by heat radiation and gas concentration assessment.
• Meter and record flared gas.

23. In the event of an emergency or equipment failure, 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 onshore facilities should be fully documented before an emergency gas venting facility is considered.

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

25. Flaring volumes for new facilities should be estimated during the design phase (Front End Engineering and Design) and tuned up during the initial commissioning period so that appropriate flaring targets can be developed, with the ability to revise targets for additional field development plans. The volumes of gas flared for all flaring events should be recorded and reported.

Well Testing

26. During well testing, flaring of produced hydrocarbons should be avoided, especially near local communities or 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 use/disposal options. Short term well testing (72 hours or less) should be preferred to long term testing in the case where exploratory wells are not connected to a pipeline network. An evaluation of alternatives for produced hydrocarbons should be adequately documented.

27. Flow-back fluids from hydraulic fracturing operations should be routed through an efficient three-phase separation unit of adequate capacity, in order to allow the separation of the gas, and the recovery of the liquid hydrocarbon and the produced water.

28. 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 duration should be reduced to the extent practical. An efficient test flare burner head equipped with an appropriate combustion enhancement system should be selected to

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9 Canadian Centre for Energy Information (www.centreforenergy.com), 2007, FLARING: QUESTIONS + ANSWERS
minimize incomplete combustion, black smoke and hydrocarbon fallout. Volumes of hydrocarbons flared should be recorded.

**Effluents from Gas Treatment Units**

29. Natural gas may contain other gases or vapors that must be removed in order to meet commercial gas specifications. Gaseous substances to be removed are, in particular, sulfur compounds, mainly hydrogen sulfide (H₂S), but also carbonyl sulfide (COS), carbon disulfide (CS₂, or “sour gas”) and carbon dioxide (CO₂, or “acid gas”); vapors may include VOCs and mercury. Gas treatment ("sweetening") generates the release of a gas stream during which the extracted compounds are concentrated. When the amount of sulfur compounds (dependent both on concentration and production rate) is high, they are usually oxidized to elemental sulfur by means of catalytic oxidation; the tail gases from such processes are generally recycled and the final effluents released to the atmosphere after thermal oxidation under controlled conditions. The effluents of thermal oxidation should meet the limits of Table 1 in section 2.1 of this Guideline.

30. Mercury can be present in natural gas in some areas, with concentration varying from a few to hundreds of micrograms per normal cubic meter (μg/Nm³). Mercury must be substantially reduced, as it may affect the further phases of treatment (failures in heat exchangers due to amalgamation)⁰¹ and to ensure that emissions do not result in mercury concentrations that reach or exceed relevant ambient quality guidelines and standards⁰¹². The treatment, by means of either regenerative or non-regenerative methods, is able to reduce the mercury concentration in gas to as low as fractions of μg/Nm³. Due to the possible release of untreated gas in case of emergency flaring or venting, a baseline survey for mercury should be undertaken before activities commence, and periodic monitoring of the mercury content in the surrounding vegetation should be implemented in the event that mercury has been detected.

**Effluents from Gas Dehydration Systems**

31. Natural gas generally contains high levels of water when produced from a reservoir, and is often saturated or at the dew point. This may result in hydrate formation or corrosion. Water should be removed to avoid resultant impacts to downstream processes; this is generally undertaken by a number of methods including glycol dehydration and molecular sieves. Regardless of the method, the regeneration phase generates an effluent stream containing water vapor, together with methane, VOCs and, in some cases, traces of mercaptans. The effluent
stream from the gas dehydration process should be treated to meet the limits in Table 1 in section 2.1 of this Guideline.

**Fugitive Emissions**

32. Fugitive emissions at onshore facilities may be associated with the leak of VOCs from process equipment cold vents (collected gaseous streams that are directly released to the atmosphere without combustion). Leak sources may include valves, flanges, pressure relief devices, process drains, open-ended valves, pump and compressor seal systems, agitator seals, access door seals, hydrocarbon loading and unloading operations, and open tanks for Non-Aqueous Drilling Fluids (NADF) (which can generate diffuse emissions).

33. Methods for controlling and reducing fugitive emissions should be considered and implemented in the design, operation, and maintenance of onshore 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. All collected gaseous streams should be burned in high efficiency flare(s), and leak detection and repair programs should be implemented.

34. The use of open vents in tank roofs should be avoided by installing pressure relief valves. Vapor control/recovery units should be installed, as needed, for the loading and unloading of tank trucks and ship tankers. Vapor processing systems may consist of different units, such as carbon adsorption, refrigeration, thermal oxidation, and lean oil absorption units. Additional guidance for the prevention and control of fugitive emissions from storage tanks is provided in the **EHS Guidelines for Crude Oil and Petroleum Product Terminals**.

**Wastewater**

35. The **General EHS Guidelines** provide information on wastewater management, water conservation and reuse, and wastewater and water quality monitoring programs. The guidance below is related to additional wastewater streams specific to the onshore oil and gas sector.

**Produced Water**

36. 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 formation water, whereas conventional gas reservoirs typically produce lesser quantities. The exception is Coal Bed Methane (CBM) reservoirs from which a large amount of produced water is initially generated. 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.

37. Produced water contains a complex mixture of inorganic (e.g., dissolved salts, trace concentrations of certain metals, suspended particles), organic (e.g., suspended and dissolved hydrocarbons, traces of fatty acids and other
organic compounds), and in some cases, residual trace concentrations of chemical additives which are used to enhance the hydrocarbon production process (e.g., scale and corrosion inhibitors, hydrate inhibitors).

38. Feasible alternatives for the management and disposal of produced water should be evaluated and integrated into facility and production design. Alternatives may include injection into the reservoir to enhance oil recovery, or injection into a dedicated disposal well drilled to a suitable receiving subsurface geological formation. Other possible uses such as irrigation, dust control, or use by other industry, may be appropriate to consider if the chemical nature of the produced water is compatible with these options, and if no adverse environmental and/or human health impacts are caused. Produced water discharges to surface waters or to land should be the last option considered and only if there is no other option available. Discharged produced water should be treated to meet the limits included in Table 1 in Section 2.1 of this Guideline.13

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

40. Sufficient storage capability should be included at the facility’s design stage to ensure continual operation, particularly to ensure capacity in the event of system failure or interruption of the disposal solution.

41. All means to reduce the volume of produced water for disposal should be considered, including:

- Adequate 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 these are technically and economically feasible; and
- Shutting in high water-producing wells.

42. Where surface disposal methods are used, production chemicals should be selected carefully to minimize environmental hazards related to residual chemical additives in the produced water stream, by considering their application rate, toxicity, bioavailability, and bioaccumulation potential.14 In particular, the use and dispersion of Kinetic Hydrate Inhibitors (KHI) should be assessed in case of discharge to surface water, to avoid possible accumulation of poorly degraded residuals.

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13 Effluent discharge to surface waters should not result in significant impact on human health and environmental receptors. A disposal plan that considers points of discharge, rate of discharge, chemical use and dispersion, and environmental risk may be necessary. Discharges should be planned away from environmentally sensitive areas, with specific attention to high water tables, vulnerable aquifers, and wetlands, as well as community receptors, including water wells, water intakes, and high-value agricultural land.

14 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.
43. Disposal to evaporation ponds may be an option for produced water. However, in a number of operating environments, evaporation rates from ponds are generally insufficient to compensate for the discharge rate. In addition, evaporation of produced water has the potential to result in the precipitation of Naturally Occurring Radioactive Materials (NORMs). Consequences include the requirement to manage the resulting sediments, where the NORMs’ concentration is generally higher than in produced water, due to the lower solubility of radium and lead carbonate and sulfate than the correspondent calcium compounds (see also the section on Waste Management—Naturally Occurring Radioactive Materials). The construction and management measures included in this Guideline for surface storage or disposal pits should also apply to produced water ponds.

Flowback Fluids

44. When hydraulic fracturing is carried out in order to allow or increase the production of hydrocarbons from tight or low-permeability geological formations, a complex mixture of water or other fluids is injected in a well under sufficient pressure to cause fracturing of the hydrocarbon bearing rocks (See Annex A for further details). The injected fluids contain proppants (solid material, typically sand, designed to keep an induced hydraulic fracture open), and a number of chemicals\textsuperscript{15} added to ease, or make more effective, the hydraulic fracturing operation. The fluid that flows back from the well to the surface after hydraulic fracturing, is generally referred to as flowback water or flowback fluids.

45. If hydraulic fracturing is planned or forms part of the project,\textsuperscript{16} as in the case of shale gas/oil projects or coalbed methane, all environmental aspects should be evaluated. This includes fracture propagation, estimated volume of fluid to be used and related possible fugitive emissions, fracturing fluid management and the fate and management of flowback water.\textsuperscript{17}

46. Flowback fluids require consideration separate from or in addition to those on produced water. Flowback water can be present in large quantities and its characteristics depend on the type of fluid and the chemicals injected to induce rock fracturing. Flowback fluids can thus constitute one of the most important environmental management issues for hydraulic fracturing operations.\textsuperscript{18}

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

\textsuperscript{15} See, beside the numerous documents under development (e.g.: US EPA—Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources, Executive Summary—Draft for review, June 2015), the published Report EUR 26347 EN, European Commission Joint Research Centre Institute for Energy and Transport (2013).

\textsuperscript{16} See International Association of Oil and Gas Producers (IOGP) (2013c); and IOGP and International Petroleum Industry Environmental Conservation Association (IPIECA) (2013).

\textsuperscript{17} Any possible social concerns (for example, related to induced microseismicity) should also be assessed.

\textsuperscript{18} See: API, 2015, Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing (API_RP_100-2).
48. If none of these alternatives is technically or economically feasible, flowback water (i.e., the aqueous phase of flowback fluids) should be treated according to the discharge guidelines provided in Table 1 of Section 2 of this Guideline prior to its disposal. An assessment of alternatives should be adequately documented. In addition, an environmental risk assessment on the chemicals mixed with the hydraulic fracturing water—including their toxicity, bioavailability, and bioaccumulation potential—should be conducted to assess the maximum site-specific allowable concentrations.

**Hydrostatic Testing Water**

49. Hydrostatic testing of onshore equipment and pipelines involves pressure testing with water to detect leaks and 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. For pipeline testing, test manifolds installed onto sections of newly constructed pipelines should be located outside of riparian zones and wetlands.

50. Water sourcing for hydrotesting purposes should not adversely affect the water level or flow rate of a natural water body, and the test water withdrawal rate (or volume) should not exceed 10 percent of the stream flow (or volume) of the water source. Erosion control measures and fish-screening controls should be implemented as necessary during water withdrawals at the intake locations.

51. Following hydrotesting, the disposal alternatives for test waters include injection into a disposal well if one is available, or discharge to surface waters or land. If a disposal well is unavailable and discharge to surface waters or land is necessary, the following pollution prevention and control measures should be considered:

- 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;
- Conduct toxicity testing as necessary using recognized test methodologies. A holding pond may be necessary in some instances to provide time for the toxicity of the water to decrease. Holding ponds should meet the guidance for surface storage or disposal pits as discussed in this Guideline;
- Use the same water for multiple tests; and
- Hydrostatic test water quality should be monitored before use and discharge and should be treated to meet the discharge limits in Table 1 of Section 2.1 of this Guideline.

52. If significant quantities of chemically treated hydrostatic test waters are required to be discharged to a surface water body, an assessment of alternatives should be adequately documented. In addition, an environmental risk assessment on the chemicals mixed with the hydraulic fracturing water—including their toxicity, bioavailability, and bioaccumulation potential—should be conducted to assess the maximum site-specific allowable concentrations:

- If discharged to surface water, consider the volume and composition of the test water, as well as the stream flow or volume of the receiving water body, in selecting an appropriate discharge site to ensure that water quality will not be adversely affected outside the defined mixing zone;
• Use break tanks or energy dissipators (e.g., protective riprap, sheeting, tarpaulins) for the discharge flow;
• Use sediment control methods (e.g., silt fences, sandbags or hay bales) to protect aquatic biota, water quality, and water users from the potential effect of discharge, such as increased sedimentation and reduced water quality;
• If discharged to land, select the discharge site in order to prevent flooding, erosion, or lowered agriculture capability of the receiving land. Avoid direct discharge on cultivated land and land immediately upstream of community/public water intakes; and
• Collect water discharge during cleaning pig runs, and pretest water in holding tanks; discharge them only after water quality testing to ensure that it meets discharge criteria established in Table 1 of Section 2.1 of this Guideline.

Cooling and Heating Systems
53. Water conservation opportunities provided in the General EHS Guideline should be considered for oil and gas facility cooling and heating systems. If cooling water is used, it should be discharged to surface waters in a location that will allow maximum mixing and cooling of the thermal plume to ensure that the temperature is within 3 degrees Celsius of ambient 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 2.1 of this Guideline.

54. If biocides and/or other chemical additives are used in the cooling water system, consideration should be given to residual effects at discharge using techniques such as a risk based assessment.

Other Waste Waters
55. Other waste waters routinely generated at onshore oil and gas facilities include sewage waters, drainage waters, tank bottom water, fire water, equipment and vehicle wash waters and general oily water. Pollution prevention and treatment measures that should be considered for these waste waters include:
• Sewage: Gray and black water from showers, toilets and kitchen facilities should be treated as described in the General EHS Guidelines.
• Drainage and storm waters: Separate drainage systems for drainage water from process areas that could be contaminated with oil (closed drains) and drainage water from non-process areas (open drains) should be available to the extent practical. All process areas should be bunded to ensure that drainage water flows into the closed drainage system and that uncontrolled contaminated surface run-off is avoided. Drainage tanks and slop tanks should be designed with sufficient capacity for foreseeable operating conditions, and systems to prevent overfilling should be installed. Drip trays, or other controls, should be used to collect run-off from equipment that is not contained within a bunded area and the contents routed to the closed drainage system. Stormwater flow channels and collection ponds installed as part of the open drainage system should be fitted with oil/water separators. Separators may include baffle type or coalescing plate type and should be regularly maintained. Stormwater runoff should be treated through an oil/water
separation system able to achieve an oil and grease concentration of 10 mg/L, as noted in Table 1 of Section 2.1 of this Guideline. Additional guidance on the management of stormwater is provided in the General EHS Guideline.

- **Tank bottom waters:** The accumulation of tank bottom waters should be minimized by regular maintenance of tank roofs and seals to prevent rainwater infiltration. If available, consideration should be given to routing these waters to the produced water stream for treatment and disposal. Alternatively they should be treated as a hazardous waste and disposed of in accordance with the facility waste management plan. Tank bottom sludges should also be periodically removed and recycled or disposed of as a hazardous waste.
- **Firewater:** Areas where firewater can be released should be drained and disposal options should be defined in the design phase. Firewater from test releases should be directed to the facility drainage system.
- **Wash waters:** Equipment and vehicle wash waters should be directed to the closed drainage system.
- **General oily water:** Oily water from drip trays and liquid slugs from process equipment and pipelines should be routed to the closed drainage system.

**Surface Storage or Disposal Pits**

56. If surface pits or ponds are used for wastewater storage or for interim disposal during operations, the pits should be constructed outside environmentally sensitive locations.

57. Wastewater pit construction and management measures should include:

- Installation of a liner so that the bottom and sides of the pit have a coefficient of permeability of no greater than 1 x 10^-7 centimeters per second (cm/sec). Typical liners may include synthetic materials, cement/clay type or natural clays. Synthetic membranes combined with a compacted clay layer should be preferred, for an effective containment. The membranes should be compatible with the material to be contained, resistant to solar UV exposure, and of sufficient strength and thickness to maintain the integrity of the pit. The hydraulic conductivity of natural liners should be tested to ensure integrity;
- A periodic integrity check should be performed together with the groundwater control through piezometers installation in case of presence of surface groundwater;
- Construction to a depth such that the bottom of the excavation is above the seasonal high water table level;
- Installation of measures (e.g., careful siting, berms) to prevent natural surface drainage from entering the pit or breaching during heavy storms;
- Installation of a perimeter and surface controls (e.g., perimeter fence, security guards) around the pit to restrict access by individuals, livestock and wildlife. Contingent on the result of the environmental assessment, mitigation measures may also include netting or screening of pits to prevent access by wildlife, particularly migratory birds 19;

19 U.S. FISH & WILDLIFE SERVICE - Reserve Pit Management: Risks to Migratory Birds (2009)
• Regular removal and recovery of free hydrocarbons from the pit contents surface;
• Removal of pit contents upon completion of operations and disposal in accordance with the waste management plan;
• Reinstatement of the pit area following completion of operations.

Waste Management

58. Typical non-hazardous and hazardous wastes\textsuperscript{20} routinely generated at onshore facilities include general office and packaging wastes, waste oils, oil contaminated rags, hydraulic fluids, used batteries, empty cans, waste chemicals and used chemical containers, used filters, fluorescent tubes, scrap metals, and medical waste, among others.

59. Efforts should be made to eliminate, reduce or recycle wastes at all times, in line with the waste hierarchy. At a minimum, the waste materials should be segregated into non-hazardous and hazardous wastes for consideration for reuse, recycling, or disposal. Waste management planning should establish a clear strategy for wastes that will be generated including options for waste elimination, reduction or recycling or treatment and disposal, before any wastes are generated. \textsuperscript{21} A waste management plan documenting the waste strategy, storage (including facilities and locations) and handling procedures should be developed and should contain a mechanism allowing waste consignments to be tracked from the originating location to the final waste treatment and disposal location.

60. Guidance for waste management of these typical wastes is provided in the General EHS Guidelines.

61. Additional waste streams that can be associated with onshore development activities are described further below, and include:
- Drilling fluids and drilled cuttings
- Produced sand
- Completion and well work-over fluids
- NORMs.

Drilling Fluids and Drilled Cuttings

62. The primary functions of drilling fluids used in oil and gas field drilling 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

\textsuperscript{20} As defined by local legislation or international conventions.
\textsuperscript{21} See OGP Report No. 413, Guidelines for Waste Management with Special Focus on Areas with Limited Infrastructure rev 1.1 September 2008 (updated March 2009)
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.

63. Various drilling fluids are available, that can generally be categorized into the following:

- **Water-Based Drilling Fluids (WBDF):** Fluids for which the continuous phase and suspending medium for solids is water or a water-miscible fluid. There are many WBDF variations, including gel, salt-polymer, salt-glycol, and salt-silicate fluids; and
- **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.

64. 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 drilling programs and should be avoided.

65. 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.

66. Drilling fluids are circulated downhole and routed to a solids removal system at the surface facilities, where fluids can be separated from the cuttings so that they may be recirculated downhole leaving the cuttings behind for disposal. These cuttings contain a proportion of residual drilling fluid. The volume of cuttings produced will depend on the depth of the well and the diameter of the hole sections drilled. The drilling fluid is replaced when its rheological properties or density of the fluid can no longer be maintained. These spent fluids are then contained for reuse or disposal (NADFs are typically reused).

67. Feasible alternatives for the treatment and disposal of drilling fluids and drilled cuttings should be evaluated and included in the planning for the drilling program. Alternative options may include one, or a combination of, the following:

- Injection of the fluid and cuttings mixture into a dedicated disposal well, where allowed by the local legislation.
- Injection into the annular space of a well.
- Storage in dedicated storage tanks or lined pits prior to treatment, recycling, and/or final treatment and disposal.
- On-site or off-site biological or physical treatment to render the fluid and cuttings non-hazardous prior to final disposal using established methods such as thermal desorption in an internal thermal desorption unit to remove NADF for re-use. Prior to adoption, bioremediation and landfarming alternatives should be assessed, in terms of feasibility, environmental impact and residual heavy metals content in soil; solidification with cement and/or concrete reduces the release of heavy metals but increases the waste...
volume and its adoption should be evaluated on the basis of the final disposal alternative. Final disposal routes for the non-hazardous cuttings solid material should be established, and may include use in road construction material, construction fill, or disposal through landfill including landfill cover and capping material where appropriate.

- In the case of landfarming it should be demonstrated that subsoil chemical, biological, and physical properties are preserved and water resources are protected; when salt saturated drilling muds are used, landfarming of the salt saturated cuttings should be avoided unless ground analysis (e.g., pH, Sodium Absorption Ratio, Electrical Conductivity) demonstrates the feasibility of the mixing with respect to the agricultural use of land.\textsuperscript{22}

- Recycling of spent fluids back to the vendors for treatment and re-use.

68. Consider minimizing volumes of drilling fluids and drilled cuttings requiring disposal by:

- Use of high efficiency solids removal systems to reduce the need for fluid change out and minimizing the amount of residual fluid on drilled cuttings.

- Use of slim-hole multilateral wells and coiled tubing drilling techniques, when feasible, to reduce the amount of fluids and cuttings generated.

69. Pollution prevention and control measures for spent drilling fluids and drilled cuttings should include the following guidelines:

- Minimize environmental hazards related to residual chemicals 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 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; and

- Monitor and minimize the concentration of heavy metal impurities (mainly lead, mercury and cadmium) in barite stock used in the fluid formulation.

70. The construction and management measures included in this guideline for surface storage or disposal pits should also apply to cuttings and drilling fluid pits. For drilling pits, closure should be completed as soon as practical, but no longer than 12 months after the end of operations. The drilling waste should be treated and disposed of according to good practices. These may include re-use of cleaned-up cuttings for road construction. De-hydration and solidification may help in facilitating their handling. Oil and Gas Producers (OGP) Guidelines for waste

\textsuperscript{22} See also Alberta Drilling Waste Management Directive 50 (July 15, 2016) http://www.aer.ca/rules-and-regulations/directives
management should be followed. If on-site burial is the only option, the following minimum conditions should be met:

- The pit contents should be dried out as far as possible;
- If necessary, the waste should be mixed with an appropriate quantity of subsoil;
- A minimum of one meter of clean subsoil should be placed over the mix;
- Topsoil should not be used for mixing but it should be placed over the subsoil to fully reinstate the area;
- The pit waste should be analyzed and tested, in order to define any possible restriction to further land use, due to poor geotechnical properties of the resulting soil; a risk based assessment may also be necessary to demonstrate that internationally recognized thresholds for chemical exposure are not exceeded; and
- Provisions should be made for closure and aftercare (including records of location and content).

**Produced Sand**

71. 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.

72. Produced sand should be treated as an oily waste, and may be treated and disposed of along with other oil contaminated solid materials (e.g., with cuttings generated when NADFs are used or with tank bottom sludges).

73. If water is used to remove oil from produced sand, it should be recovered and routed to an appropriate treatment and disposal system (e.g., the produced water treatment system when available).

**Completion and Well Work-Over Fluids**

74. 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 simply used to maintain downhole pressure. Once used, these fluids may contain contaminants including solid material, oil, and chemical additives. Chemical systems should be selected with consideration of their volume, toxicity, bioavailability, and bioaccumulation potential.

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

- Collect the fluids where handled in closed systems and ship them back to the original vendors for recycling;
- Inject into a disposal well, where available;

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23 OGP Report No. 413, "Guidelines for waste management with special focus on areas with limited infrastructure" rev1.1 September 2008 (updated March 2009)
• Include as part of the produced water waste stream for treatment and disposal. Spent acids should be neutralized before treatment and disposal; and
• On-site or off-site biological or physical treatment at an approved facility in accordance with the waste management plan.

Naturally Occurring Radioactive Materials (NORM)
76. Depending on the field reservoir characteristics, NORM may be present in the produced fluids. NORM may precipitate as scale or sludge in evaporation ponds, process piping, and production vessels in which the concentration of NORM can be higher than in the fluid. 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.

77. If removal of NORM is required, disposal options may include canister disposal during well abandonment, deep well or salt cavern injection, injection into the annular space of a well or disposal to landfill in sealed containers.

78. NORM-containing sludge, scale, or equipment should be treated, processed, isolated and/or disposed of according to good international industry practices, so that potential future human exposure to the treated waste will be within internationally accepted limits. If waste is sent to an external facility for disposal, the facility must be licensed to receive such waste.

Hazardous Materials Management
79. General guidance for the definition and management of hazardous materials is provided in the General EHS Guidelines.

80. The following additional principles should be followed for the management of hazardous materials chemicals in the onshore oil and gas sector:
• 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 with least hazard and lowest potential environmental and health risks, whenever possible;
• Avoid chemicals suspected to cause taint or known endocrine disruptors;
• ODS should not be used for new facilities; and
• Avoid chemicals known to contain heavy metals of concern, in anything other than trace quantities.

For more on the management of NORM residues, see International Atomic Energy Agency (IAEA) (2013).


ICRP (2007).

Noise

81. Oil and gas development activities can generate noise and vibrations during all phases of development including during seismic surveys, construction activities, drilling and production, aerial surveys and air, road or waterway transportation. During operations, the main sources of noise and vibration pollution are likely to emanate from drilling rigs, as well as from flaring and rotating equipment. Noise sources include flares and vents, pumps, compressors, generators, valves and gages, and heaters. Noise prevention and control measures are described in the General EHS Guidelines, along with the recommended daytime and night time noise level guidelines for urban or rural communities.

82. Noise impacts should be estimated by the use of baseline noise assessments for developments close to local sensitive receptors. For significant noise sources, such as flare stacks at permanent processing facilities, noise dispersion models should be conducted to establish that the noise level guidelines can be met and to assist in the design of facility siting, stack heights, engineered sound barriers, and sound insulation on buildings.

83. Field related vehicle traffic should be reduced as far as possible and access through local communities should be avoided when not necessary and particularly during sensitive times. Flight access routes and low flight altitudes should be selected and scheduled to reduce noise impacts without compromising personnel and community safety, aircraft integrity and security. General guidance on minimizing noise and vibration caused by project transportation is provided in the General EHS Guidelines.

84. The sound and vibration propagation arising from seismic operations may result in impacts to human populations or to wildlife. In planning seismic surveys, the following should be considered to minimize impacts:

- Minimize seismic activities in the vicinity of local populations wherever possible;
- Minimize simultaneous operations on closely spaced survey lines;
- Use the lowest practicable vibrator power levels in view of data quality requirements in environmentally sensitive and populated areas;
- Reduce operation times in environmentally sensitive and populated areas to the extent practical;
- When shot-hole methods are employed, charge size and hole depth should be appropriately selected to reduce noise levels. Proper back-fill or plugging of holes will also help to reduce noise dispersion;
- Identify areas and time periods sensitive to wildlife such as feeding and breeding locations and seasons and avoid them when possible; and
- If sensitive wildlife species are located in the area, monitor their presence before the onset of noise creating activities, and throughout the seismic program. In areas where significant impacts to sensitive species are anticipated, experienced wildlife observers should be used. Slowly build up activities in sensitive locations.
Terrestrial Impacts and Project Footprint

85. Project footprints resulting from exploration and construction activities may include seismic tracks, well pads, temporary facilities, such as workforce base camps, material (pipe) storage yards, workshops, access roads, airstrips and helipads, piers and jetties construction, equipment staging areas, and construction material extraction sites (including borrow pits and quarries).

86. Operational footprints may include well pads, permanent processing treatment, transmission and storage facilities, pipeline right-of-way corridors, access roads, ancillary facilities, communication facilities (e.g., antennas), and power generation and transmission lines. Impacts may include loss of, or damage to, terrestrial habitat, creation of barriers to wildlife movement, soil erosion, and disturbance to water bodies including possible sedimentation, the establishment of non-native invasive plant species and visual disturbance. The extent of the disturbance will depend on the activity along with the location and characteristics of the existing vegetation, topographic features and waterways.

87. The visual impact of permanent facilities should be considered in design so that impacts on the existing landscape are minimized. The design should take advantage of the existing topography and vegetation, and should use low profile facilities and storage tanks if technically feasible and if the overall facility footprint is not significantly increased. In addition, consider suitable paint color for large structures that can blend with the background. General guidance on minimizing the project footprint during construction and decommissioning activities is provided in the General EHS Guidelines.

88. Additional prevention and control measures to minimize the footprint of onshore oil and gas developments may include the following:

- Site all facilities in locations that avoid critical terrestrial and aquatic habitat and plan construction activities to avoid sensitive times of the year;
- Minimize land requirements for aboveground permanent facilities;
- Minimize areas to be cleared. Use hand cutting where possible, avoiding the use of heavy equipment such as bulldozers, especially on steep slopes, water and wetland crossings, and forested and ecologically sensitive areas;
- Use a central processing/treatment facility for operations, when practical;
- Minimize well pad size for drilling activities and satellite/cluster, directional, extended reach drilling techniques should be considered, and their use maximized in sensitive locations;
- Avoid construction of facilities in a floodplain, whenever practical, and within a distance of 100 m of the normal high-water mark of a water body or a water well used for drinking or domestic purposes;
- Carefully consider the effects of piers and jetties in riverine, estuarine and coastal areas, in order to reduce erosion and damage to the local flora and fauna;
• Consider the use of existing utility and transport corridors for access roads and pipeline corridors to the extent possible;
• Consider the routing of access roads to avoid induced impacts such as increased access for poaching;
• Minimize the width of a pipeline right-of-way or access road during construction and operations as far as possible;
• Limit the amount of pipeline trench left open during construction at any one time. Safety fences and other methods to prevent people or animals (livestock or wildlife) from falling into open trenches should be constructed in sensitive locations and within 500 m of human populations. In remote areas, install wildlife escape ramps from open trenches (typically every 1 km where wildlife is present);
• Consider use of animal crossing structures such as bridges, culverts, and over crossings, along pipeline and access road rights-of-way;
• Bury pipelines along the entire length to a minimum of 1 m to the top-of-pipe, wherever this is possible;
• Carefully consider all of the feasible options for the construction of pipeline river crossings including horizontal directional drilling;
• Construction areas no longer needed by a project development should be appropriately reclaimed, including by appropriate revegetation using native plant species and establishing/re-establishing appropriate drainage contours. Where applicable, accommodate requests of the local population regarding the reclaimed state of the disturbed land;
• Reinstall off-site aggregate extraction facilities including borrow pits and quarries (opened specifically for construction or extensively used for construction);
• Prepare and implement repair and maintenance programs for reinstated sites;
• Consider the opportunity of reducing the seismic lines width and line of sight to the minimum practicable;
• Consider shot-hole methods in place of vibroseis where preservation of vegetation cover is required and when access is limited. In areas of low cover (e.g., deserts, or tundra with snow cover in place), vibroseis machinery should be selected, but soft soil locations should be carefully assessed to prevent excessive compaction;
• Install appropriate erosion and sediment control measures, slope stabilization measures, and subsidence control and minimization measures at all facilities, as necessary;
• Regularly maintain vegetation growth along access roads and at permanent above ground facilities, and avoid introduction of invasive plant species. In controlling vegetation, use biological, mechanical and thermal vegetation control measures and evaluate by risk assessment the use of appropriate chemical herbicides; and
• Establish a procedure for appropriately managing contaminated soil or buried waste, when encountered.
89. If it is demonstrated that the use of herbicides is required to control vegetation growth along access roads or at facilities, then personnel must be trained in their use. Additional guidance on the use of pesticides is provided in the **EHS Guidelines for Annual Crop Production**.

**Impacts on subsoil and aquifers**

90. When drilling a well, the subsoil can be affected by the drilling operation itself, as well as by the fluids utilized for drilling bit cooling and lubrication and for cuttings removal from the borehole. The possible impacts induced by drilling should be accurately considered in the Environmental and Social Impact Assessment.

91. In particular, the possible impact on usable aquifers (exploited or potentially exploitable) for drinking, agricultural or industrial water should be prevented during drilling operations, by properly selecting the drilling fluids during the initial phases of drilling (low density, low filtrate, low chemical content), when the exploitable aquifers are expected to be encountered. The casing profile of the well should be designed with well suspension and final abandonment in mind, taking care of the above mentioned aquifers, in order to protect and isolate the aquifer sections\(^{28}\), lost circulation zones and abnormally pressured zones. Cementing operations should be monitored and relevant information should be recorded to evaluate the quality of the cement job.

92. When hydraulic fracturing is part of the appraisal or development program:

- Accurate modeling of the fracture propagation effects (including the location of faults and fractures, the depths of all usable water, and estimated direction and length of fractures) should be provided.\(^ {29}\) in order to guarantee that aquifers containing exploited and exploitable water resources are not affected by possible migration of hydrocarbon or other fluids through the fractures system.\(^ {30}\)

- Prior to starting hydraulic fracturing operations, the operator should:
  - Determine and document that there is adequate cement for all casing strings used to isolate and protect usable water zones.
  - Perform a successful mechanical integrity test.\(^ {31}\)

93. During the hydraulic fracturing operation, well pressures should be monitored and recorded to avoid over-pressurization.

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94. Properly designed monitoring wells, installed in the above mentioned aquifers, should be foreseen and constructed in order to assess any possible migration and consequent contamination related to the hydraulic fracturing operations. A long term monitoring program should be defined and put in place and results made available to all interested stakeholders. The duration of the monitoring program should be defined on the basis of the geo-hydrological characteristics of the subsoil in the area where hydraulic fracturing is carried out.

95. An operational action plan should be prepared for effective intervention in case of any possible contamination of the aquifers containing exploited and exploitable water resources.

96. At the end of the productive life of a field, a program of plugging and cementing the wells should be defined and implemented in order to avoid any further migration of fluids between subsoil formations.

Spills
97. Spills from onshore facilities, including pipelines, can occur due to leaks, equipment failure, accidents, human error or as a result of third party interference. 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 onshore oil and gas facilities include the following tasks:

- Conduct a spill risk assessment for the onshore facilities;
- Design process, utility, and drilling systems to reduce the risk of major uncontained spills;
- Install Blowout Prevention Systems (BOP) during drilling phases along with emergency shut off valves during construction to reduce production risk by enabling early shutdown or isolation during emergency events;
- 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;
- Install secondary containment around vessels and tanks to contain accidental releases;
- Install shutdown valves to allow early shutdown or isolation in the event of a spill;
- Develop automatic shutdown actions through an emergency shutdown system for significant spill scenarios so that the facility may be rapidly brought into a safe condition;
- Install early alert and detection systems in case of any leak. On pipelines, consider measures such as telemetry systems, Supervisory Control and Data Acquisition systems,32 pressure sensors, shut-in valves, and pump-off systems, including at normally unattended installations and unmanned facilities to ensure rapid detection of any loss of containment;
- Conduct routine surveys of remote installations and connection systems (flow lines, clusters, manifolds) for early detection of dangerous conditions, by direct survey or by use of remote technologies (e.g., drones) and/or by monitoring methods (e.g., vibration, noise process parameters changes);

32 These may be used in oil and gas and other industrial facilities to assist in the monitoring and control of plants and equipment.
• Develop maintenance and monitoring programs to ensure the integrity of all field equipment. For flowlines and pipelines, maintenance programs should include regular pigging to clean the line, and intelligent pigging should be considered as required. An Asset Integrity Management program based also on risk-based methods (e.g., Risk Based Inspection) should be developed from the design phase and enforced during the facility operation;

• An Emergency Shutdown System should be in place in all facilities, able to initiate automatic shutdown actions to bring the 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; and

• Ensure that spill response and containment equipment are routinely inspected, maintained, and operationally exercised and tested—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.

Spill Response Planning

98. 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 by the project development phase and based on the initial project design, and it should include community consultation and feedback.

99. The SRP should address potential oil, chemical, and fuel spills from facilities, transportation vehicles, loading and unloading operations, and pipeline ruptures and leaks. The SRP shall define the emergency management organization and process (e.g., following the Incident Command System (ICS) approach). The plan should include at least the following:

• A description of the operations, site conditions, logistical support arrangements and oil properties;

• A spill risk assessment, defining expected frequency and size of spills from potential release sources, including an assessment of foreseeable scenarios;\(^{33}\)

• Clear definition of spill severity, according to the size and location of a spill, and the foreseen effects on the affected environmental components, with a defined tiered approach. Strategies for managing spills, based on expected severity and possible location of the spill;

• In the event that surface water bodies are likely to be impacted, a specific section on impact on water should be included in the SRP and guidance for Spill Response, Planning should be provided to the response team(s), taking into account the most updated GIIP for the development of spill response

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\(^{33}\) See also IOGP (2013c), as a reference in case of fracking; and IOGP and IPIECA (2013).
capability for oil spills in water (e.g., water intakes protection by the means of deflection booming, positioning the absorbent booms across the river current);\textsuperscript{34,35}

- For sensitive areas, such as wetlands, swamp and mangroves, specific response strategies should be selected;\textsuperscript{36}
- Ranking of foreseeable spill scenarios in terms of potential severity, taking into account the expected spilled amount and the morphological, physical, biological and socioeconomic characteristics of the likely impacted environment;
- 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 the environment with regard to the expected spill should include: land morphology and soil characteristics; groundwater and surface water resources; sensitive ecological and protected areas; agricultural land; residential, industrial, recreational, cultural, and landscape features of significance and seasonal aspects for relevant features; and
- Cooperative measures with government agencies as appropriate, and relevant notification process and procedures.

100. The SRP should also include the following:

- Full list, description, location, and use of on-site and off-site response equipment and the response times for deployment (minimum equipment for specialized contractor’s/external resources further actions may also be included).
- Storage and maintenance instructions for spill response equipment and relevant routine inspection, testing, and exercises.
- Arrangements and procedures to mobilize external resources in responding to larger spills and strategies for their deployment.
- Priorities for response (with input from potentially affected or concerned parties).
- Methods to maximize recovery and response capabilities (e.g., remote sensing, aerial observation, command and control, infrared systems).
- Clean up strategies and handling instructions including their transport, temporary storage, and disposal for recovered spilled oil, chemicals, fuels, and other recovered contaminated materials but also for surface soil, subsoil, aquifers and surface waters as applicable.
- Measures to rehabilitate wildlife.

\textsuperscript{34} See, e.g.; OGP Report Number 519, \textit{Contingency Planning for Oil Spills on Water— Good Practice Guidelines for the Development of an Effective Spill Response capability} (January 2015) and OGP Report Number 526, \textit{Tiered Preparedness and Response—Good Practice Guidelines for Using the Tiered Preparedness and Response framework} (January 2015).

\textsuperscript{35} IPIECA, IOGP, 2015 \textit{Oil Spills:Inland Response Good Practice Guidelines for Incident Management and Emergency Response Personnel}.

Measures to be taken to protect health and safety of oil spill response personnel, and for the local population.

Decommissioning

101. Decommissioning of onshore facilities usually includes the removal of permanent facilities and well abandonment, including associated equipment, material, and waste disposal or recycling. General guidance on the prevention and control of common environmental impacts during decommissioning activities is provided in the General EHS Guidelines. Specific additional requirements to consider for oil and gas facilities include well abandonment and pipeline decommissioning options.

102. Wells should be abandoned in a stable and safe condition. The hole should be sealed to the surface with cement plugs and any known zones containing pressurized fluids should be isolated to prevent fluid migration to either the surface or between different aquifers. If the land is used for agriculture, the surface casing should be cut and capped below plow depth.

103. Decommissioning options for pipelines include leaving them in place, or removing them for reuse, recycling or disposal, especially if they are above ground and interfere with human activities. Pipelines left in place should be disconnected and isolated from all potential sources of hydrocarbons; cleaned and purged of free hydrocarbons; and sealed at their ends.

104. A preliminary decommissioning and restoration plan should be developed that identifies disposal options for all equipment and materials, including products used and wastes generated on site. The plan should consider the removal of oil from flowlines, the removal of surface equipment and facilities, well abandonment, pipeline decommissioning and reinstatement. The 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.

105. Guidance for the management of EHS issues related to contaminated land is provided in section 1.8 of the General EHS Guidelines.

1.2 Occupational Health and Safety

106. Occupational health and safety and major hazard issues should be considered as part of a comprehensive risk assessment through, for example, a combination including a HAZID study, HAZOP study, or other risk assessment studies that encompass occupational hazards as well as major accident hazards (including blowout risk). The results should be used for health and safety management planning, in the design of the facility and safe working systems, and in the preparation and communication of safe working procedures. Health and safety management planning should demonstrate, also through the development of a formal Safety Case, that a
systematic and structured approach to managing 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.

107. Facilities should be designed to eliminate or reduce the potential for injury or risk of an accident and should take into account prevailing environmental conditions at the site location including the potential for extreme natural hazards such as earthquakes or hurricanes.

108. 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.

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

110. The 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 complexity of the facility, provision of an on-site medical unit and health care professional may need to be considered. In specific cases, telemedicine facilities may be an alternative option.

111. A visual and acoustic alarm system should be installed that can be heard throughout the facility, or to alert the remote control center for unmanned facilities. Alarms for fire, H2S and hydrocarbon gas leak should be provided.

112. 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 and documented to the entire workforce.

113. 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.

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37 National Academy of Engineering (NAE) and National Research Council of the National Academies (NRCNA) (2011); Transportation Research Board of the National Academies (TRBNA) (2012).
in the General EHS Guidelines. These guidelines also provide guidance on Personal Protective Equipment (PPE) for workers.

114. Additional occupational health and safety issues in onshore oil and gas operations include the following:

- Asset Integrity Management;
- Fire and explosion;
- Air quality;
- Hazardous materials;
- Transportation;
- Well blowouts; and
- Emergency preparedness and response.

**Asset Integrity Management**

115. Any failure during the operations phase, may lead to unplanned hazardous material releases representing a loss of production and a serious environmental and safety risk. In order to avoid this, an Asset Integrity Management (AIM)\(^\text{38}\) process should be established, commencing from the design phase. The AIM process during the design phase must identify the hazards and the related barriers provided to prevent and/or mitigate the hazards, and set the required performance standards (performance is described in terms of functionality, availability, reliability and survivability for the barriers). The AIM plan during facility operation will ensure integrity of barriers by proper inspections and maintenance plans; risk-based approaches such as Reliability Based Inspection and Reliability Centered Maintenance are suggested to identify the type and frequency of inspections and maintenance.

**Fire and Explosion**

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

117. Onshore oil and gas development facilities should be designed, constructed, and operated according to international standards\(^\text{39}\) for the prevention and control of fire and explosion hazards. The most effective ways to prevent fires and explosions at oil and gas facilities is to prevent the release of flammable material and gas, to implement early detection procedures and to ensure the repair of leaks. Potential ignition sources should be kept to a minimum and adequate separation distances between potential ignition sources and flammable materials, and between processing facilities and adjacent buildings,\(^\text{40}\) 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.

\(^{38}\) OGP, 2008 Asset Integrity – the Key to Managing Major Incident Risks. OGP Report No. 415


\(^{40}\) Further information on safe spacing is available in the US NFPA Code 30.
Facilities should be classified into various hazard areas, based on international standards, and in accordance with the likelihood of release of flammable gases and liquids.

118. Appropriate fire and explosion prevention and control measures should include the following:

- Provide passive fire protection throughout the facility (load-bearing structures, fire-rated walls, and fire-rated partitions between rooms) to prevent the spread of fire in the event of an incident including fire protection measures should be designed on the basis of consideration of the fire hazard.
  - Take into account explosion loads in the design of load-bearing structures or install blast-rated walls.
- Control potential ignition sources through techniques such as:
  - Proper grounding to avoid static electricity buildup and lightning hazards (including formal procedures for the use and maintenance of grounding connections).
  - Use of intrinsically safe electrical installations and non-sparking tools.
- Conduct a fire impact assessment to determine the type and extent of fire detection and protection required for the facility. A combination of automatic and manual fire alarm systems are typically provided at the facility. Active fire protection systems should be installed at the facility and should be strategically located to enable rapid and effective response. The fire suppression equipment should meet internationally recognized technical specifications for the type and amount of flammable and combustible materials at the facility. A combination of active fire suppression systems 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, mixed dry chemical system, fixed wet chemical system, fire water monitors, live hose reels, and portable equipment such as fire extinguishers, and specialized vehicles). For new 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 is essential.
- Ensure the protection of manned buildings by distance or by fire walls. The ventilation air intakes shall be designed to prevent smoke and flammable or hazardous gases from entering buildings.
- 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.

41 Such as American Petroleum Institute (API) (1997c, 1997d) Recommended Practices 500 and 505; International Electrotechnical Commission; or British Standards.
42 API (2013b).
44 See ISGOTT, Chapter 19.
45 Such as the US NFPA or equivalent standards.
Avoid explosive atmospheres in confined spaces by making spaces inert or by including adequate ventilation.

Implementation of safety procedures for loading and unloading of product to transport systems (e.g., ship tankers, rail and tankers), including use of fail-safe control valves and emergency shutdown equipment.

Preparation of a fire response plan supported by the necessary resources to implement the plan.

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.

Air Quality

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

Due to the risk of gas releases caused by leaks or emergency events, adequate ventilation in closed or partially closed spaces is required at oil and gas facilities. Air intakes should be installed to ventilate the 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.

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.

Wherever hydrogen sulfide (H₂S) gas may accumulate the following measures should be considered:

- Develop a contingency plan for H₂S release events, including all necessary aspects from evacuation to resumption of normal operations;
- Install monitors set to activate warning signals whenever detected concentrations of H₂S exceed 7 milligrams per cubic meter (mg/m³). The number and location of monitors should be determined based on an assessment of plant locations prone to H₂S emission and occupational exposure;
- Provide personal H₂S detectors to workers in locations of high risk of exposure along with self-contained breathing apparatus and emergency oxygen supplies that is conveniently located to enable personnel to safely interrupt tasks and reach a temporary refuge or safe haven;
- Provide adequate ventilation of occupied buildings to avoid accumulation of hydrogen sulfide gas; and
- Provide workforce training in safety equipment use and response in the event of a leak.

An example of good industry practice for loading and unloading of tankers includes ISGOTT.

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.
Hazardous Materials

123. The design of the onshore 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 substituted 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.

124. A procedure for the control and management of radioactive sources used during operations should be prepared, along with a designated and 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.

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

126. 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.

Well Blowouts

127. A blowout (i.e. loss of well control) can be caused by the uncontrolled flow of reservoir fluids into the wellbore which 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.

128. Blowout prevention (BOP) measures during drilling should focus on maintaining wellbore hydrostatic pressure by effectively estimating formation fluid pressures and the strength of subsurface formations. This can be achieved with techniques such as proper pre-well planning 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.

129. 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 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. Facility personnel should conduct well control drills at regular intervals and key personnel should attend a certified well control school periodically, well control training and drills should be documented. BOP testing should be conducted by an independent specialist, particularly for critical wells (e.g., 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.

130. During production, wellheads should be regularly maintained and monitored for corrosion control and inspection and pressure monitoring. Blow out contingency measures should be included in the facility Emergency Response Plan.

131. The BOP system design, maintenance, and repair should be in general compliance with international standards. It is recommended that, at a minimum, 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.

132. 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.

133. 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.

**Transportation**

134. Incidents related to land transport are one of the main causes of injury and fatality in the oil and gas industry. Traffic safety measures for industries are provided in the General EHS Guidelines.

135. Oil and gas projects should develop a road safety management plan for the facility during all phases of operations. Measures should be in place to train all drivers in safe and defensive driving methods and the safe
transportation of passengers. Speed limits for all vehicles should be implemented and enforced. Vehicles should be maintained in an appropriate road worthy condition and include all necessary safety equipment.  

136. Specific safety procedures for air transportation (including by helicopter) of personnel and equipment should be developed and a safety briefing for passengers should be systematically provided along with safety equipment. Helicopter decks at or near to facilities should follow the requirements of the International Civil Aviation Organization (ICAO).

Emergency Preparedness and Response

137. Guidance relating to emergency preparedness and response, including emergency resources, is provided in the General EHS Guidelines. Onshore oil and gas facilities should establish and maintain a high level of emergency preparedness to ensure that the response to incidents is prompt and effective. Potential worst-case accidents should be identified by risk assessment and appropriate preparedness requirements should be designed. An emergency response team should be established for the facility; 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.

138. Personnel should be provided with adequate and sufficient equipment, including medical emergency equipment and evacuation devices. These devices shall be appropriately located for the evacuation of the facility. 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 exercises should be implemented:

- Drills without equipment deployment as a minimum on quarterly basis;
- Evacuation drills and training for egress from the facilities 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;
- 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).
  - A 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 description of equipment, consumables, and support systems to be utilized;

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48 See 2014, Land Transportation Safety Recommended Practice, OGP Report No. 365 (September 2014).
• 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;
• Evacuation procedures;
• Emergency Medical Evacuation (MEDI-VAC) procedures for injured or ill personnel; and
• Policies defining measures for limiting or stopping events, and conditions for termination of action.

1.3 Community Health and Safety

139. Community health and safety impacts during the construction and decommissioning of facilities are common to those of most other industrial facilities and are discussed in the General EHS Guidelines.

Physical Hazards

140. Community health and safety issues specific to oil and gas facilities may include potential exposure to spills, fires, and explosions. To protect nearby communities and related facilities from these hazards, the location of the project facilities and an adequate safety zone around the facilities should be established based on a risk assessment and maintained, without encroachment into the safety zone. A community emergency preparedness and response plan that considers the role of communities and community infrastructure as appropriate should also be developed with relevant authorities and disseminated. Signs that indicate the presence of underground pipes or unattended facilities should include emergency phone numbers and, if relevant, corresponding Kilometer Point (KP) labels. Additional information on the elements of emergency plans is provided in the General EHS Guidelines.

141. Communities may be exposed to physical hazards associated with the facilities including wells and pipeline networks. Hazards may result from contact with hot components, equipment failure, attempted theft or third party alteration of equipment, components and/or materials, the presence of operational pipelines or active and abandoned wells and abandoned infrastructure which may generate confined space or falling hazards. To prevent public contact with dangerous locations and equipment and hazardous materials, access deterrents such as fences and warning signs should be installed around permanent facilities and temporary structures. Routine surveys of remote installations and pipelines, conducted by direct survey or by use of remote technologies (e.g., drones) and/or by monitoring methods (e.g., vibration, noise process parameters changes) could additionally prevent any dangerous interaction of communities with facilities; these measures are also suggested as a spill prevention measure. Public training to warn of existing hazards, emergency response measures, and clear guidance on access and land use limitations in safety zones or pipeline rights of way, should be provided.

142. Project decommissioning plans should ensure risks are identified and mitigated to the extent possible to ensure communities and the environment are protected from physical, chemical, or other hazards associated with sites during and after decommissioning. For abandoned wells, plans should provide specifications for the cement
plugging\(^a\) and post-decommissioning monitoring, in order to prevent any fluid slipping after closure and abandonment. Until decommissioning activities are completed, all facilities and equipment should remain fenced or guarded to avoid unintended interaction with local communities. The release of the areas to local communities should be granted only after all hazards have been removed. Additional information on decommissioning is provided in the General EHS Guidelines.


### Hydrogen Sulfide

144. The potential for exposure of members of the community to facility air emissions should be carefully considered during the facility design and operations planning process. All necessary precautions in the facility design, facility siting and/or working systems and procedures should be implemented to ensure no health impacts to human populations and the workforce will result from activities.

145. When there is a risk of community exposure to hydrogen sulfide from activities, the following measures should be implemented:

- Installation of a hydrogen sulfide gas monitoring network with the number and location of monitoring stations determined through air dispersion modeling, taking into account the location of emissions sources and areas of community use and habitation;
- Continuous operation of the hydrogen sulfide gas monitoring systems to facilitate early detection and warning;
- Emergency planning involving community input to allow for effective response to monitoring system warnings.

### Security

146. Unauthorized access to facilities (e.g., well heads, gathering stations, security and check valves, borrow pits, construction areas, processing stations, leach fields) should be restricted through a combination of institutional and administrative controls that include fencing, controlled access points, signage and communication of risks to the local community. Additional guidance is provided in section 4.3 of the General EHS Guidelines.

Impacts on Land Use

147. In well fields, the presence of well pads, pipelines, flow lines, above and below ground cables and access roads can potentially dissect a land use parcel leaving parts of it physically difficult to access or too small to be viable for agriculture, thus negatively impacting community/individual livelihoods. Moreover, the scattered location of numerous well pads in an area might limit people freedom of movement. The project should avoid and minimize severance and fragmentation of land and land plots, in particular through the consolidation into corridors of access roads, flow lines and cabling for well pads to minimize project footprint or, when avoidance or minimization are not possible, provide appropriate compensation/mitigation measures.

2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

148. Table 1 shows effluent guidelines for onshore 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.

| Table 1. Emissions, Effluent, and Waste Levels from Onshore Oil and Gas Development |
|-------------------------------|----------------------------------|
| Parameter                        | Guideline Value                          |
| Drilling fluids and cuttings | Treatment and disposal as per guidance in Section 1.1 of this document. |
| Produced sand                  | Treatment and disposal as per guidance in Section 1.1 of this document. |
| Produced water                 | Treatment and disposal as per guidance in Section 1.1 of this document. For discharge to surface waters or to land:  |
|                               | • Total hydrocarbon content: 10 mg/L.  |
|                               | • pH: 6–9.                                   |
|                               | • BOD: 25 mg/L.                               |
|                               | • COD: 125 mg/L.                              |
|                               | • TSS: 35 mg/L.                               |
|                               | • Phenols: 0.5 mg/L.                          |
|                               | • Sulfides: 1 mg/L.                           |
|                               | • Heavy metals (total)*: 5 mg/L.             |
|                               | • Chlorides: 600 mg/L (average), 1200 mg/L (maximum). |
| Hydrotest water               | Treatment and disposal as per guidance in section 1.1 of this document. For discharge to surface waters or to land, see parameters for produced water in this table. |
| Completion and well work-over fluids | Treatment and disposal as per guidance in Section 1.1 of this document. For discharge to surface waters or to land:  |
|                               | • Total hydrocarbon content: 10 mg/L.  |
|                               | • pH: 6 – 9.                                   |
| Stormwater drainage           | Stormwater runoff should be treated through an oil/water separation system able to achieve oil & grease concentration not exceeding 10 mg/L. |
Table 1. Emissions, Effluent, and Waste Levels from Onshore Oil and Gas Development

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Guideline Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cooling water</td>
<td>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.</td>
</tr>
<tr>
<td>Sewage</td>
<td>Treatment as per guidance in the General EHS Guidelines, including discharge requirements.</td>
</tr>
</tbody>
</table>
| Air Emissions   | Treatment as per guidance in Section 1.1 of this document. Emission concentrations as per General EHS Guidelines, and:  
  o $\text{H}_2\text{S}$: 5 mg/Nm$^3$                                                                                                         |

Notes: a Heavy metals include: arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, vanadium, and zinc.

149. Effluent guidelines are applicable for direct discharges of treated effluents to surface waters for general use. Site-specific discharge levels may be established based on the availability and conditions in use of publicly operated sewage collection and treatment systems or, if discharged directly to surface waters, on the receiving water use classification as described in the General EHS Guidelines.

150. Combustion source emissions guidelines associated with steam, heat recovery (or any combination of these) and/or electrical or mechanical 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.

Environmental Monitoring

151. Environmental monitoring programs for this sector should be implemented 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.

152. 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

153. 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.

**Occupational Health and Safety Guidelines**

154. 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 (BEIs®) published by American Conference of Governmental Industrial Hygienists (ACGIH);[^50] Pocket Guide to Chemical Hazards published by the United States National Institute for Occupational Health and Safety (NIOSH),[^51] Permissible Exposure Limits (PELs) published by the Occupational Safety and Health Administration of the United States (OSHA),[^52] Health Leading Performance Indicators, published by IPIECA and IOGP),[^53] Indicative Occupational Exposure Limit Values published by European Union member states,[^54] or other similar sources. Particular attention should be given to the occupational exposure guidelines for hydrogen sulfide (H₂S).

155. 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.[^55]

**Accident and Fatality Rates**

156. Projects are encouraged to identify and use leading indicators in their Environmental, Health, and Safety improvement programs, and should invest in the systematic reduction of 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).[^56]

**Occupational Health and Safety Monitoring**

157. 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.[^57] Facilities should also maintain a record of occupational accidents and diseases, as

[^51]: http://www.cdc.gov/niosh/npg/.
[^53]: OGP, 2013 Health Leading Performance Indicators—2012 Data Report No. 2012h (June 2013)
[^54]: Available at: http://europe.osha.eu.int/good_practice/risks/ds/oel/
[^55]: ICRP (2007)
[^56]: Available at: https://www.bls.gov/iif/ and http://www.hse.gov.uk/statistics/index.htm
[^57]: Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.
well as dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the General EHS Guidelines.
3.0 References and Additional Sources


BIO Intelligence Service, 2013, *Analysis and presentation of the results of the public consultation—Unconventional fossil fuels (e.g., shale gas) in Europe*, Final report prepared for European Commission DG Environment.


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Environmental, Health, and Safety Guidelines
ONSHORE OIL AND GAS DEVELOPMENT

DRAFT: April 4th, 2017


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———. 2007, Natural Gas Dehydration—Lessons Learned from the Natural Gas Star Program—Producers Technology Transfer Workshop, College Station, Texas—May 17, 2007 http://www3.epa.gov/gasstar/


Annex A: General Description of Industry Activities

158. The primary products of the 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 (associated gas), 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 (NGL).

Exploration Activities

Seismic Surveys

159. Seismic surveys are conducted to pinpoint potential hydrocarbon reserves in geological formations. Seismic technology uses the reflection of sound waves to identify subsurface formations. The surveys are conducted through the generation of seismic waves by a variety of sources ranging from explosives that are detonated in shot-holes drilled below the surface, to vibroseis machinery (a vibrating pad lowered to the ground from a vibroseis truck). Reflected seismic waves are measured with a series of sensors known as geophones laid out in series on the surface.

Exploration Drilling

160. Exploratory drilling activities onshore follow the analysis of seismic data to verify and quantify the amount and extent of oil and gas resources from potentially productive geological formations. A well pad is constructed at the chosen location to accommodate a drilling rig, associated equipment and support services. The drilling rig and support services are transported to site, typically in modules, and assembled.

161. Once on location, a series of well sections of decreasing diameter is 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 cuttings rock 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. 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 to establish reservoir properties in a test separator.
Field Development and Production

162. Development and production is the phase during which the infrastructure is installed to extract the hydrocarbon resource over the life of the estimated reserve. It may involve the drilling of additional wells, the operation of central production facilities to treat the produced hydrocarbons, the installation of flowlines, and the installation of pipelines to transport hydrocarbons to export facilities.

163. Following development drilling and well completion, a “Christmas tree” is placed on each wellhead to control flow of the formation fluids to the surface. Hydrocarbons may flow freely from the wells if the underground formation pressures are adequate, but additional pressure may be required such as a sub-surface pump or the injection of gas or water through dedicated injection wells to maintain reservoir pressure. Depending on reservoir conditions, various substances (steam, nitrogen, carbon dioxide, and surfactants) may be injected into the reservoir to remove more oil from the pore spaces, increase production, and extend well life.

164. Most wells produce in a predictable pattern called a decline curve where production increases relatively rapidly to a peak, and then follows a long, slow decline. Operators may periodically perform well workovers to clean out the wellbore, allowing oil or gas to move more easily to the surface. Other measures to increase production include fracturing and treating the bottom of the wellbore with acid to create better pathways for the oil and gas to move to the surface. Formation fluids are then separated into oil, gas and water at a central production facility, designed and constructed depending on the reservoir size and location.

165. Crude oil processing essentially involves the removal of gas and water before export. Gas processing involves the removal of liquids and other impurities such as carbon dioxide, nitrogen and hydrogen sulfide. Oil and gas terminal facilities receive hydrocarbons from outside locations sometimes offshore and process and store the hydrocarbons before they are exported. There are several types of hydrocarbon terminals, including inland pipeline terminals, onshore/coastal marine receiving terminals (from offshore production), barge shipping, or receiving terminals.

166. Produced oil and gas may be exported by pipeline, trucks, or rail tank cars. Gas-to-liquids is an area of technology development that allows natural gas to be converted to a liquid. Gas is often exported as liquefied natural gas (LNG). Pipelines are constructed in a sequential process, including staking of the right-of-way (ROW) and pipeline centerline; ROW clearing and grading; trenching (for buried pipeline); pipe laying, welding, and bending; field coating of welded joints; testing; lowering; trench backfilling; and ROW reinstatement. Pumps or compressors are used to transport liquids or gas from the oil and gas fields to downstream or export facilities. During commissioning, flowlines, pipelines, and associated facilities (e.g., block valves and meters, regulators and relief devices, pump stations, pigging stations, storage tanks) are filled with water and hydrotested to ensure integrity. Pipeline operation usually requires frequent inspections (ground and aerial surveillance, and facility inspections) and periodic ROW and facility maintenance. Production and pipeline operation is usually monitored and controlled...
from a central location through a supervisory control and data acquisition system (SCADA) which allows field operating variables to be monitored such as flow rate, pressure, and temperature and to open and close valves.

Hydraulic Fracturing

167. 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 controversial58, hydraulic fracturing has been used on a smaller scale for many years to improve the flow from conventional oil and gas wells, or in case of drill cutting and spent drilling fluids re-injection. Today, hydraulic fracturing is largely applied onshore, with some applicability in offshore fields, in “unconventional” hydrocarbon development, and in order to produce oil and gas from geological formation having very low permeability. Differences exist between the technical arrangements adopted for “conventional” and “non-conventional” cases, the latter involving higher pressure and fluid volumes, in addition to a wider range of additives. Differences also exist between offshore and onshore. Hydraulic fracturing for “unconventional” oil and gas development typically involves injecting, through the wellhead, high volumes of water, or other fluids, mixed with sand and fractional amounts of chemical additives. Different fluids can be used, such as hydrocarbons or gases (CO₂, N₂, Helium, Natural gas) and foams. The injection pressure is a function of the well depth and the rock characteristics. When water is used as the base of hydraulic fracturing fluid, the average composition of the injected mixture is generally 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 be present in low concentrations. In case of high permeability formations, the fracturing fluid will usually be more viscous and have a higher sand concentration. Water based fluids cannot be used when the hydrocarbon containing shale is sensitive to water; the above mentioned alternative fluids are preferably used in such cases. Many hydraulic fracturing techniques have been developed in recent years and continue to be developed, imposing specific attention to the management of the fluids and chemicals used for optimizing the results. The use of methanol or other volatile substances also present OHS hazard. Multistage hydraulic fracturing is now a commonly utilized approach.

Coalbed Methane

168. Coalbed methane (CBM) is frequently developed onshore. Some cases may include hydraulic fracturing (see above) to improve production performance. CBM wells are characterized by high water production, which requires specific treatment systems (produced water from CBM usually has a low concentration of oil and grease, generally associated with the presence of heavy metals and hydrophilic compounds that must be removed prior to discharge).

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58 See BIO Intelligence Service (2013) Analysis and presentation of the results of the public consultation; Unconventional Fossil Fuels (e.g., shale gas) in Europe, Final report prepared for European Commission DG Environment.
Decommissioning and Abandonment

169. The decommissioning of onshore facilities occurs when the reservoir is depleted or the production of hydrocarbons from that reservoir becomes unprofitable. Parts of the onshore facilities, such as the aboveground facilities located in the oil or gas field area and along the transmission lines, are treated to remove hydrocarbons and other chemicals and wastes or contaminants. Other components, such as flowlines and pipelines, are often left in place to avoid environmental disturbances associated with removal.

170. Wells are plugged and abandoned to prevent fluid migration within the wellbore or to the surface. The downhole equipment is removed and the perforated parts of the wellbore are cleaned of soil, scale, and other debris. The wellbore is then plugged. 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 with a cement plug.