

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

Introduction

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/ifcext/enviro.nsf/Content/EnvironmentalGuidelines

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. 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.

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.

The applicability of specific technical recommendations should be based on the professional opinion of qualified and experienced persons. 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

The EHS Guidelines for Onshore Oil and Gas Development include information relevant to seismic exploration; exploration and production drilling; development and production activities; transportation activities including 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**. This document is organized according to the following sections:

Section 1.0 — Industry-Specific Impacts and Management
Section 2.0 — Performance Indicators and Monitoring
Section 3.0 — References
Annex A — General Description of Industry Activities

1.0 Industry-Specific Impacts and Management

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. Additional guidance for the management of EHS issues common to most large industrial facilities during the construction phase is provided in the **General EHS Guidelines**.

1.1 Environment

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 / effluent discharges
- Solid and liquid waste management
- Noise generation
- Terrestrial impacts and project footprint
- Spills

Air Emissions

The main sources of air emissions (continuous or non-continuous) resulting from onshore activities include: combustion sources from power and heat generation, and the use of compressors, pumps, and reciprocating engines (boilers, turbines, and other engines); emissions resulting from flaring and venting of hydrocarbons; and fugitive emissions.

Principal pollutants from these sources include nitrogen oxides, sulfur oxides, carbon monoxide, and particulates. Additional pollutants can include: hydrogen sulfide (H₂S); volatile organic

compounds (VOC) methane and ethane; benzene, ethyl benzene, toluene, and xylenes (BTEX); glycols; and polycyclic aromatic hydrocarbons (PAHs).

Significant (>100,000 tons CO₂ equivalent per year) greenhouse gas (GHG) emissions from all facilities and support activities should be quantified annually as aggregate emissions in accordance with internationally recognized methodologies and reporting procedures.²

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

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.

Exhaust gases

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

² Additional guidance on quantification methodologies can be found in IFC Guidance Note 3, Annex A, available at www.ifc.org/envsocstandards

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

Venting and Flaring

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

However, flaring or venting are also important safety measures used on onshore oil and gas facilities to ensure gas and other hydrocarbons are safely disposed of in the event of an emergency, power or equipment failure, or other plant upset condition.

Measures consistent with the Global Gas Flaring and Venting Reduction Voluntary Standard (part of the World Bank Group's Global Gas Flaring Reduction Public-Private Partnership (GGFR program³) should be adopted when considering flaring and venting options for onshore activities. The standard provides guidance on how to eliminate or achieve reductions in the flaring and venting of natural gas.

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

Alternative options may include gas utilization for on-site energy needs, export of the gas to a neighboring facility or to market, gas injection for reservoir pressure maintenance, enhanced recovery using gas lift, or gas for instrumentation. An assessment of alternatives should be adequately documented and recorded. If none of the alternative options are currently feasible, then 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.

If flaring is necessary, continuous improvement of flaring through implementation of best practices and new technologies should be demonstrated. The following pollution prevention and control measures should be considered for gas flaring:

- Implementation of source gas reduction measures to the maximum extent possible;
- Use of efficient flare tips, and optimization of the size and number of burning nozzles;
- Maximizing flare combustion efficiency by controlling and optimizing flare fuel / air stream flow rates to ensure the correct ratio of assist stream to flare stream;
- Minimizing flaring from purges and pilots, without compromising safety, through measures including installation of purge gas reduction devices, flare gas recovery units, inert purge gas, soft seat valve technology where appropriate, and installation of conservation pilots;
- Minimizing risk of pilot blow-out by ensuring sufficient exit velocity and providing wind guards;
- Use of a reliable pilot ignition system;
- Installation of high integrity instrument pressure protection systems, where appropriate, to reduce over pressure events and avoid or reduce flaring situations;
- Minimizing liquid carry-over and entrainment in the gas flare stream with a suitable liquid separation system;

³ World Bank Group (2004)

- Minimizing flame lift off and / or flame lick;
- Operating flare to control odor and visible smoke emissions (no visible black smoke);
- Locating flare at a safe distance from local communities and the workforce including workforce accommodation units;
- Implementation of burner maintenance and replacement programs to ensure continuous maximum flare efficiency;
- Metering flare gas.

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

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

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

Fugitive Emissions

Fugitive emissions at onshore facilities may be associated with cold vents, leaking pipes and tubing, valves, connections, flanges, packings, open-ended lines, pump seals, compressor seals, pressure relief valves, tanks or open pits / containments, and hydrocarbon loading and unloading operations.

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

Use of open vents in tank roofs should be avoided by installing pressure relief valves. Vapor control units should be installed, as needed, for the loading and unloading of 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 are provided in the **EHS Guidelines for Crude Oil and Petroleum Product Terminals**.

Well Testing

During well testing, flaring of produced hydrocarbons should be avoided wherever practical and possible, and especially near local communities or in environmentally sensitive areas. Feasible alternatives should be evaluated for the recovery of hydrocarbon test fluids, while considering the safety of handling volatile hydrocarbons, for transfer to a processing facility or other alternative disposal options. An evaluation of disposal alternatives for produced hydrocarbons should be adequately documented and recorded.

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

hydrocarbon fallout. Volumes of hydrocarbons flared should be recorded.

Wastewaters

The **General EHS Guidelines** provide information on wastewater management, water conservation and reuse, along with 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

Oil and gas reservoirs contain water (formation water) that is produced when brought to the surface during hydrocarbon production. The produced water stream can be one of the largest waste products, by volume, managed and disposed of by the onshore oil and gas industry. Produced water contains a complex mixture of inorganic (dissolved salts, trace metals, suspended particles) and organic (dispersed and dissolved hydrocarbons, organic acids) compounds, and in many cases, residual chemical additives (e.g. scale and corrosion inhibitors) that are added into the hydrocarbon production process.

Feasible alternatives for the management and disposal of produced water should be evaluated and integrated into production design. The main disposal alternatives may include injection into the reservoir to enhance oil recovery, and 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. 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.⁴

Produced water treatment technologies will depend on the final disposal alternative selected and particular field conditions. Technologies to consider may include combinations of gravity and / or mechanical separation and chemical treatment, and may require a multistage system containing a number of technologies in series to meet injection or discharge requirements. Sufficient treatment system backup capability should be in place to ensure continual operation and or an alternative disposal method should be available.

To reduce the volume of produced water for disposal the following should be considered:

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

To minimize environmental hazards related to residual chemical additives in the produced water stream where surface disposal methods are used, production chemicals should be selected carefully by taking into account their volume, toxicity, bioavailability, and bioaccumulation potential.

Disposal into evaporation ponds may be an option for produced waters. The construction and management measures included

⁴ 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, and community receptors, including water wells, water intakes, and high-value agricultural land.

in this Guideline for surface storage or disposal pits should also apply to produced water ponds.

Hydrostatic Testing Water

Hydrostatic testing of equipment and pipelines involves pressure testing with water to detect leaks and verify equipment and pipeline integrity. Chemical additives (corrosion inhibitors, oxygen scavengers, 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.

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.

The disposal alternatives for test waters following hydrotesting include injection into a disposal well if one is available or discharge to surface waters or land surface. If a disposal well is unavailable and discharge to surface waters or land surface 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;
- If chemical use is necessary, 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 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 hydrotest water for multiple tests;
- Hydrostatic test water quality should be monitored before use and discharge and should be treated to meet the discharge limits in Table 1 in Section 2.1 of this Guideline.
- If significant quantities of chemically treated hydrostatic test waters are required to be discharged to a surface water body, water receptors both upstream and downstream of the discharge should be monitored. Post-discharge chemical analysis of receiving water bodies may be necessary to demonstrate that no degradation of environmental quality has occurred;
- If discharged to water, the volume and composition of the test water, as well as the stream flow or volume of the receiving water body, should be considered in selecting an appropriate discharge site to ensure that water quality will not be adversely affected outside of 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, the discharge site should be selected to prevent flooding, erosion, or lowered agriculture capability of the receiving land. Direct discharge on cultivated land and land immediately upstream of community / public water intakes should be avoided;
- Water discharge during cleaning pig runs and pretest water should be collected in holding tanks and should be discharged 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

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 within 100 meters of the discharge point, as noted in Table 1 of Section 2.1 of this Guideline.

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 risk based assessment.

Other Waste Waters

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 banded to ensure 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 banded 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. Consideration should be given to routing these waters to the produced water stream for treatment and disposal, if available. 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:* 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

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.

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 1×10^{-7} centimeters per second (cm/sec). Liners should be compatible with the material to be contained and of sufficient strength and thickness to maintain the integrity of the pit. Typical liners may include synthetic materials, cement / clay type or natural clays, although the hydraulic conductivity of natural liners should be tested to ensure integrity;
- Construction to a depth of typically 5 m above the seasonal high water table;
- 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 fence around the pit or installation of a screen to prevent access by people, livestock and wildlife (including birds);
- 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

Typical non-hazardous and hazardous wastes⁵ routinely generated at onshore facilities other than permitted effluents and emissions include general office and packaging wastes, waste oils, paraffins, waxes, oil contaminated rags, hydraulic fluids, used batteries, empty paint cans, waste chemicals and used chemical containers, used filters, fluorescent tubes, scrap metals, and medical waste, among others.

⁵ As defined by local legislation or international conventions.

Waste materials should be segregated into non-hazardous and hazardous wastes for consideration for re-use, 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. A waste management plan documenting the waste strategy, storage (including facilities and locations) and handling procedures should be developed and should include a clear waste tracking mechanism to track waste consignments from the originating location to the final waste treatment and disposal location. Guidance for waste management of these typical waste streams is provided in the **General EHS Guidelines**.

Significant additional waste streams specific to onshore oil and gas development activities may include:

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

Drilling Fluids and Drilled Cuttings

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 hydraulic energy to the drilling tools and bit. Drilled cuttings removed from the wellbore and spent drilling fluids are typically the largest waste streams generated during oil and gas drilling activities. Numerous drilling fluid systems are available, but they can generally be categorized into one of two fluid systems:

- *Water-Based Drilling Fluids (WBDF)*: The continuous phase and suspending medium for solids (or liquid) is

water or a water miscible fluid. There are many WBDF variations, including gel, salt-polymer, salt-glycol, and salt-silicate fluids;

- *Non-Aqueous Drilling Fluids (NADF)*: The continuous phase and suspending medium for solids (or liquid) is a water immiscible fluid that is oil-based, enhanced mineral oil-based, or synthetic-based.

Diesel-based fluids are also available, but the use of systems that contain diesel as the principal component of the liquid phase is not considered current good practice.

Typically, the solid medium used in most drilling fluids is barite (barium sulfate) for weight, with bentonite clays as a thickener. Drilling fluids also contain a number of chemicals that are added depending on the downhole formation conditions.

Drilling fluids are circulated downhole and routed to a solids control 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 or at the end of the drilling program. These spent fluids are then contained for reuse or disposal (NADFs are typically reused).

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;
- 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, bioremediation, landfarming, or solidification with cement and / or concrete. 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;
- Recycling of spent fluids back to the vendors for treatment and re-use.

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

- Use of high efficiency solids control equipment 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.

Pollution prevention and control measures for spent drilling fluids and drilled cuttings should include:

- Minimizing environmental hazards related to residual chemicals additives on discharged cuttings by careful selection of the fluid system.
- Careful selection of fluid additives taking into account technical requirements, chemical additive concentration, toxicity, bioavailability and bioaccumulation potential;

- Monitoring and minimizing the concentration of heavy metal impurities (mainly mercury and cadmium) in barite stock used in the fluid formulation.

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, pit closure should be completed as soon as practical, but no longer than 12 months, after the end of operations. If the drilling waste is to be buried in the pit following operations (the Mix-Bury-Cover disposal method), 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 (typically three parts of subsoil to one part of waste by volume);
- A minimum of one meter of clean subsoil should be placed over the mix;
- Topsoil should not be used but it should be placed over the subsoil to fully reinstate the area.
- The pit waste should be analyzed and the maximum lifetime loads should be calculated. A risk based assessment may be necessary to demonstrate that internationally recognized thresholds for chemical exposure are not exceeded.

Produced Sand

Produced sand originating from the reservoir is separated from the formation fluids during hydrocarbon processing. The produced sand can be contaminated with hydrocarbons, but the oil 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.

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).

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

Completion and well work-over fluids (including intervention and service fluids) can typically include weighted brines, acids, methanol and glycols, and other chemical systems. 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. Feasible disposal options should be evaluated for these fluids. Alternative disposal options may include one, or a combination of, the following:

- Collection of the fluids if handled in closed systems and shipping to the original vendors for recycling;
- Injection to a dedicated disposal well, where available;
- Inclusion as part of the produced water waste stream for treatment and disposal. Spent acids should be neutralized before treatment and disposal;
- On-site or off-site biological or physical treatment at an approved facility in accordance with the waste management plan.

Naturally Occurring Radioactive Materials

Depending on the field reservoir characteristics, naturally occurring radioactive material (NORM) may precipitate as scale or sludges in process piping and production vessels. Where

NORM is present, a NORM management program should be developed so that appropriate handling procedures are followed.

If removal of NORM is required for occupational health reasons (section 1.2), 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.

Sludge, scale, or NORM-impacted equipment should be treated, processed, or isolated so that potential future human exposures to the treated waste would be within internationally accepted risk-based limits. Recognized industrial practices should be used for disposal. If waste is sent to an external facility for disposal, the facility must be licensed to receive such waste.

Hazardous Materials Management

General guidance for the management of hazardous materials is provided in the **General EHS Guidelines**. The following additional principles should be followed for chemicals used in the onshore oil and gas sector:

- Use chemical hazard assessment and risk management techniques to evaluate chemicals and their effects. Selected chemicals should have been tested for environmental hazards;
- Select chemicals with least hazard and lowest potential environmental and / or health impact, whenever possible;
- Use of Ozone Depleting Substances⁶ should be avoided.

Noise

Oil and gas development activities can generate noise during all phases of development including during seismic surveys, construction activities, drilling and production, aerial surveys and air or road transportation. During operations, the main sources

of noise and vibration pollution are likely to emanate from flaring and rotating equipment. Noise sources include flares and vents, pumps, compressors, generators, 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.

Noise impacts should be estimated by the use of baseline noise assessments for developments close to local human populations. For significant noise sources, such as flare stacks at permanent processing facilities, noise dispersion models should be conducted to establish 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.

Field related vehicle traffic should be reduced as far as possible and access through local communities should be avoided when not necessary. Flight access routes and low flight altitudes should be selected and scheduled to reduce noise impacts without compromising aircraft and security.

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;
- Reduce operation times, 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;

⁶ As defined by the Montreal Protocol on Substances That Deplete the Ozone Layer.

- Identify areas and time periods sensitive to wildlife such as feeding and breeding locations and seasons and avoid them when possible;
- 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 buildup activities in sensitive locations.

Terrestrial Impacts and Project Footprint

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, equipment staging areas, and construction material extraction sites (including borrow pits and quarries).

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.

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**.

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;
- 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 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;
- Clean-up and fully reinstate following construction activities (including appropriate revegetation using native plant species following construction activities) the pipeline right-of-way and temporary sites such as workforce accommodation camps, storage yards, access roads, helipads and construction workshops, to the pre-existing topography and drainage contours;
- Reinstate off-site aggregate extraction facilities including borrow pits and quarries (opened specifically for construction or extensively used for construction);
- Implement repair and maintenance programs for reinstated sites;
- Consider the implementation of low impact seismic techniques (e.g. minimize seismic line widths (typically no wider than 5 m), limit the line of sight along new cut lines in forested areas (approximately 350 m));
- 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 temporary and permanent 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 avoid the use of chemical herbicides as much as possible.

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. Herbicides that should be avoided include those listed under the World Health Organization recommended Classification of Pesticides by Hazard Classes 1a and 1b, the World Health Organization recommended Classification of Pesticides by Hazard Class II (except under conditions as noted in IFC Performance Standard 3: Pollution Prevention and Abatement;⁷), and Annexes A and B of the Stockholm Convention, except under the conditions noted in the convention.⁸

Spills

Spills from onshore facilities, including pipelines, can occur due to leaks, equipment failure, accidents, and 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.

⁷ IFC Performance Standard 3: Pollution Prevention and Abatement (2006). Available at www.ifc.org/envsocstandards

⁸ Stockholm Convention on Persistent Organic Pollutants (2001).

Additional spill prevention and control measures specific to onshore oil and gas facilities include:

- Conduct a spill risk assessment for the facilities and design, drilling, process, and utility systems to reduce the risk of major uncontained spills;
- Ensure adequate corrosion allowance for the lifetime of the facilities 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 leak detection systems. On pipelines consider measures such as telemetry systems, Supervisory Control and Data Acquisition (SCADA⁹), pressure sensors, shut-in valves, and pump-off systems,
- Develop corrosion maintenance and monitoring programs to ensure the integrity of all field equipment. For pipelines, maintenance programs should include regular pigging to clean the pipeline, and intelligent pigging should be considered as required;
- Ensure adequate personnel training in oil spill prevention, containment, and response;
- Ensure spill response and containment equipment is deployed or available for a response.

All spills should be documented and reported. Following a spill, a root cause investigation should be carried out and corrective

actions should be undertaken to prevent reoccurrence. A Spill Response Plan should be prepared, and the capability to implement the plan should be in place. The Spill Response Plan should address potential oil, chemical, and fuel spills from facilities, transport vehicles, loading and unloading operations, and pipeline ruptures. The plan should include:

- A description of the operations, site conditions, logistic support and oil properties;
- Identification of persons responsible for managing spill response efforts, including their authority, roles and contact details;
- Documentation of cooperative measures with government agencies as appropriate;
- Spill risk assessment, defining expected frequency and size of spills from different potential release sources;
- Oil spill trajectory in potentially affected surface water bodies, with oil fate and environmental impact prediction for a number of credible most-probable spill simulations (including a worst case scenario, such as blowout from an oil well) using an adequate and internationally recognized computer model;
- Clear demarcation of spill severity, according to the size of the spill using a clearly defined Tier I, Tier II and Tier III approach;
- Strategies and equipment for managing Tier I spills at a minimum;
- Arrangements and procedures to mobilize external resources for responding to larger spills and strategies for deployment;
- Full list, description, location, and use of on-site and off-site response equipment and the response time estimates for deploying equipment;
- Sensitivity mapping of the environment at risk. Information should include: soil types; groundwater and surface water resources; sensitive ecological and protected areas;

⁹ SCADA refers to supervisory control and data acquisition systems, which may be used in oil and gas and other industrial facilities to assist in the monitoring and control of plants and equipment.

agricultural land; residential, industrial, recreational, cultural, and landscape features of significance; seasonal aspects for relevant features, and oil spill response types to be deployed;

- Identification of response priorities, with input from potentially affected or concerned parties;
- Clean up strategies and handling instructions for recovered oil, chemicals, fuels or other recovered contaminated materials, including their transportation, temporary storage, and treatment / disposal.

Decommissioning

Decommissioning of onshore facilities usually includes the complete 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.

Wells should be abandoned in a stable and safe condition. The hole should be sealed to the ground surface with cement plugs and any known hydrocarbon zones should be isolated to prevent fluid migration. Aquifers should also be isolated. If the land is used for agriculture, the surface casing should be cut and capped below plow depth.

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 hydrocarbons; and sealed at its ends.

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 should be further developed during field operations and fully defined in advance of the end of field life, and should include details on the provisions for the implementation of decommissioning activities and arrangements for post decommissioning monitoring and aftercare.

1.2 Occupational Health and Safety

Occupational health and safety issues should be considered as part of a comprehensive hazard or risk assessment, including, for example, a hazard identification study [HAZID], hazard and operability study [HAZOP], or other risk assessment studies. 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.

Facilities should be designed to eliminate or reduce the potential for injury or risk of 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.

Health and safety management planning should demonstrate: 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; that staff are adequately trained; and that equipment is maintained in a safe condition. The formation of a health and safety committee for the facility is recommended.

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 all equipment is isolated from energy sources before servicing or removal.

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

General facility design and operation measures to manage principal risks to occupational health and safety are provided in the **General EHS Guidelines**. General guidance specific to construction and decommissioning activities is also provided along with guidance on health and safety training, personal protective equipment and the management of physical, chemical, biological and radiological hazards common to all industries.

Occupational health and safety issues for further consideration in onshore oil and gas operations include:

- Fire and explosion
- Air quality
- Hazardous materials
- Transportation
- Well blowouts
- Emergency preparedness and response

Fire and Explosion

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

Onshore oil and gas development facilities should be designed, constructed, and operated according to international standards¹⁰ for the prevention and control of fire and explosion hazards. The most effective way of preventing fires and explosions at oil and gas facilities is by preventing the release of flammable material and gas, and the early detection and interruption of leaks. Potential ignition sources should be kept to a minimum and adequate separation distance between potential ignition sources and flammable materials, and between processing facilities and adjacent buildings¹¹, should be in place. Facilities should be classified into hazard areas, based on international good practice,¹² and in accordance with the likelihood of release of flammable gases and liquids.

Facility fire and explosion prevention and control measures should also include:

- Provision of passive fire protection to prevent the spread of fire in the event of an incident including:
 - Passive fire protection on load-bearing structures, fire-rated walls, and fire-rated partitions between rooms
 - Design of load-bearing structures taking into account explosion load, or blast-rated walls
 - Design of structures against explosion and the need for blast walls based on an assessment of likely explosion characteristics

¹⁰ An example of good practice includes the United States (US) National Fire Protection Association (NFPA) Code 30: Flammable and Combustible Liquids Code. Further guidance to minimize exposure to static electricity and lightning is American Petroleum Institute (API) Recommended Practice: Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents (2003).

¹¹ Further information on safe spacing is available in the US NFPA Code 30.

¹² See API RP 500/505 task group on electrical area classification, International Electrotechnical Commission, or British Standards (BS).

- Specific consideration of blast panel or explosion venting, and fire and explosion protection for wellheads, safe areas, and living areas;
- Prevention of potential ignition sources such as:
 - Proper grounding to avoid static electricity buildup and lightning hazards (including formal procedures for the use and maintenance of grounding connections)¹³
 - Use of intrinsically safe electrical installations and non-sparking tools¹⁴
- A combination of automatic and manual fire alarm systems that can be heard across the facility;
- Active fire protection systems 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.¹⁵ 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, and portable equipment such as fire extinguishers, and specialized vehicles). The installation of halon-based fire systems is not considered current good practice and should be avoided. Firewater pumps should be available and designed to deliver water at an appropriate rate. Regular checks and maintenance of fire fighting equipment is essential;
- All fire systems should be located in a safe area of the facility, protected from the fire by distance or by fire walls. If the system or piece of equipment is located within a potential fire area, it should be passive fire protected or fail-safe;
- Explosive atmospheres in confined spaces should be avoided by making spaces inert;
- Protection of accommodation areas by distance or by fire walls. The ventilation air intakes should prevent smoke from entering accommodation areas;
- Implementation of safety procedures for loading and unloading of product to transport systems (e.g. ship tankers, rail and tanker trucks, and vessels¹⁶), 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;
- Provision of fire safety training and response as part of workforce health and safety induction / training, including training in the use fire suppression equipment and evacuation, with advanced fire safety training provided to a designated fire fighting team.

Air Quality

Guidance for the maintenance of air quality in the workplace, along and provision of a fresh air supply with required air quality levels, is provided in the **General EHS Guidelines**.

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. Equipment isolation or the 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:

- Development of a contingency plan for H₂S release events, including all necessary aspects from evacuation to resumption of normal operations;

¹³ See International Safety Guide for Oil Tankers and Terminals (ISGOTT) Chapter 20.

¹⁴ See ISGOTT, Chapter 19.

¹⁵ Such as the US NFPA or equivalent standards.

¹⁶ An example of good industry practice for loading and unloading of tankers includes ISGOTT.

- Installation of 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;
- Provision of 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;
- Provision of adequate ventilation of occupied buildings to avoid accumulation of hydrogen sulfide gas;
- Workforce training in safety equipment use and response in the event of a leak.

Hazardous Materials

The design of the onshore facilities should reduce exposure of personnel to chemical substances, fuels, and products containing hazardous substances. Use of substances and products classified as very 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 (MSDS) should be available and readily accessible on the facility. A general hierarchical approach to the prevention of impacts from chemical hazards is provided in the **General EHS Guidelines**.

A procedure for the control and management of any radioactive sources used during operations should be prepared along with a designated and shielded container for storage when the source is not in use.

In locations where naturally occurring radioactive material (NORM) may precipitate as scale or sludges in process piping and production vessels, facilities and process equipment should

be monitored for the presence of NORM at least every five years, or whenever equipment is to be taken out of service for maintenance. Where NORM is detected, a NORM management program should be developed so that appropriate handling procedures are followed. Procedures should determine the classification of the area where NORM is present and the level of supervision and control required. Facilities are considered impacted when surface levels are greater than 4.0 Bq/cm² for gamma/beta radiation and 0.4 Bq/cm² for alpha radiation.¹⁷ The operator should determine whether to leave the NORM in-situ, or clean and decontaminate by removal for disposal as described in Section 1.1 of this Guideline.

Well Blowouts

A blowout can be caused by the uncontrolled flow of reservoir fluids into the wellbore which may result in an uncontrolled release of hydrocarbons. Blowout prevention measures during drilling should focus on maintaining wellbore hydrostatic pressure by effectively estimating formation fluid pressures and strength of subsurface formations. This can be achieved with techniques such as: proper pre-well planning, drilling fluid logging; using sufficient density drilling fluid or completion fluid to balance the pressures in the wellbore; and installing a Blow Out Preventor (BOP) system that can be rapidly closed in the event of an uncontrolled influx of formation fluids and which allows the well to be circulated to safety by venting the gas at surface and routing oil so that it may be contained. The BOP should be operated hydraulically and triggered automatically, and tested at regular intervals. Facility personnel should conduct well control drills at regular intervals and key personnel should attend a certified well control school periodically.

During production, wellheads should be regularly maintained and monitored, by corrosion control and inspection and pressure

¹⁷ US Environmental Protection Agency (EPA) 49 CFR 173: Surface Contaminated Object (SCO) and International Atomic Energy Agency (IAEA) Safety Standards Series No. ST-1, §508

monitoring. Blow out contingency measures should be included in the facility Emergency Response Plan.

Transportation

Incidents related to land transportation 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**.

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.

Specific safety procedures for air transportation (including 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

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 incidents are responded to effectively and without delay. Potential worst case accidents should be identified by risk assessment and appropriate preparedness requirements should be designed and implemented. An emergency response team should be established for the facility that is trained to respond to potential emergencies, rescue injured persons, and perform emergency actions. The team should coordinate actions with

other agencies and organizations that may be involved in emergency response.

Personnel should be provided with adequate and sufficient equipment that is located appropriately for the evacuation of the facility and should be provided with escape routes to enable rapid evacuation to a safe refuge. Escape routes should be clearly marked and alternative routes should be available. Exercises in emergency preparedness should be practiced at a frequency commensurate with the project risk. At a minimum, the following practice schedule should be implemented:

- Quarterly drills without equipment deployment;
- Evacuation drills and training for egress from the facilities under different weather conditions and time of day;
- Annual mock drills with deployment of equipment;
- Updating training, as needed, based on continuous evaluation.

An Emergency Response Plan should be prepared that contains the following measures, at a minimum:

- A description of the response organization (structure, roles, responsibilities, and decision makers);
- Description of response procedures (details of response equipment and location, procedures, training requirements, duties, etc.);
- Descriptions and procedures for alarm and communications systems;
- Precautionary measures for securing the wells;
- Relief well arrangements, including description of equipment, consumables, and support systems to be utilized;
- Description of on-site first aid supplies and available backup medical support;
- Description of other emergency facilities such as emergency fueling sites;

- Description of survival equipment and gear, alternate accommodation facilities, and emergency power sources;
- Evacuation procedures;
- Emergency Medical Evacuation (MEDIVAC) procedures for injured or ill personnel;
- Policies defining measures for limiting or stopping events, and conditions for termination of action.

1.3 Community Health and Safety

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

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. A community emergency preparedness and response plan that considers the role of communities and community infrastructure as appropriate should also be developed. Additional information on the elements of emergency plans is provided in the **General EHS Guidelines**.

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, 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. Public training to warn of existing hazards, along with clear guidance on access and land use limitations in safety zones or pipeline rights of way should be provided.

Community risk management strategies associated with the transport of hazardous materials by road is presented in the **General EHS Guidelines** (refer specifically to the sections on "Hazardous Materials Management" and "Traffic Safety"). Guidance applicable to transport by rail is provided **EHS Guidelines for Railways** while transport by sea is covered in the **EHS Guidelines for Shipping**.

Hydrogen Sulfide

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.

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

Unauthorized access to facilities should be avoided by perimeter fencing surrounding the facility and controlled access points (guarded gates). Public access control should be applied. Adequate signs and closed areas should establish the areas where security controls begin at the property boundaries. Vehicular traffic signs should clearly designate the separate entrances for trucks / deliveries and visitor / employee vehicles. Means for detecting intrusion (for example, closed-circuit television) should be considered. To maximize opportunities for surveillance and minimize possibilities for trespassers, the facility should have adequate lighting.2.0

2.0 Performance Indicators and Monitoring

2.1 Environment

Emissions and Effluent Guidelines

Table 1 presents effluent and waste guidelines for onshore oil and gas development. 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. 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.

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**.

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

Environmental Monitoring

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. Performar

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

Table 1. 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: <ul style="list-style-type: none"> ○ 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)^a: 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: <ul style="list-style-type: none"> ○ 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 of 10 mg/L.
Cooling water	The effluent should result in a temperature increase of no more than 3° C at edge of the zone where initial mixing and dilution take place. Where the zone is not defined, use 100 m from point of discharge.
Sewage	Treatment as per guidance in the General EHS Guidelines, including discharge requirements.
Air Emissions	Treatment as per guidance in Section 1.1 of this document. Emission concentrations as per General EHS Guidelines, and: <ul style="list-style-type: none"> ○ H₂S: 5 mg/Nm³
Notes:	
^a Heavy metals include: Arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, vanadium, and zinc.	

2.2 Occupational Health and Safety

Occupational Health and Safety Guidelines

Occupational health and safety performance should be evaluated against internationally published exposure guidelines, of which examples include the Threshold Limit Value (TLV®) occupational exposure guidelines and Biological Exposure Indices (BEIs®) published by American Conference of Governmental Industrial Hygienists (ACGIH),¹⁸ the Pocket Guide to Chemical Hazards published by the United States National Institute for Occupational Health and Safety (NIOSH),¹⁹ Permissible Exposure Limits (PELs) published by the Occupational Safety and Health Administration of the United States (OSHA),²⁰ Indicative Occupational Exposure Limit Values published by European Union member states,²¹ or other similar sources.

Particular attention should be given to the occupational exposure guidelines for hydrogen sulfide (H₂S). For guidelines on occupational exposure to Naturally Occurring Radioactive Material (NORM), readers should consult the average and maximum values published by the Canadian NORM Waste Management Committee, Health Canada, and the Australian Petroleum Production and Exploration Association or other internationally recognized sources.

Accident and Fatality Rates

Projects should try to reduce the number of accidents among project workers (whether directly employed or subcontracted) to a rate of zero, especially accidents that could result in lost work time, different levels of disability, or even fatalities. Facility rates may be benchmarked against the performance of facilities in this sector in developed countries through consultation with

published sources (e.g. US Bureau of Labor Statistics and UK Occupational Health and Safety Executive)²².

Occupational Health and Safety Monitoring

The working environment should be monitored for occupational hazards relevant to the specific project. Monitoring should be designed and implemented by accredited professionals²³ as part of an occupational health and safety monitoring program. Facilities should also maintain a record of occupational accidents and diseases and dangerous occurrences and accidents. Additional guidance on occupational health and safety monitoring programs is provided in the **General EHS Guidelines**.

¹⁸ Available at: <http://www.acgih.org/TLV/> and <http://www.acgih.org/store/>

¹⁹ Available at: <http://www.cdc.gov/niosh/hpg/>

²⁰ Available at: http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARD&p_id=9992

²¹ Available at: http://europe.osha.eu.int/good_practice/risks/ds/oe/

²² Available at: <http://www.bls.gov/iif/> and <http://www.hse.gov.uk/statistics/index.htm>

²³ Accredited professionals may include Certified Industrial Hygienists, Registered Occupational Hygienists, or Certified Safety Professionals or their equivalent.

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Annex A: General Description of Industry Activities

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, or wells can be drilled with natural gas as the primary objective. Methane is the predominant component of natural gas, but ethane, propane, and butane are also significant components. The heavier components, including propane and butane, exist as liquids when cooled and compressed and these are often separated and processed as natural gas liquids.

Exploration Activities

Seismic Surveys

Seismic surveys are conducted to pinpoint potential hydrocarbon reserves in geological formations. Seismic technology uses the reflection of sound waves to identify subsurface geological structures. 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

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.

Once on location, a series of well sections of decreasing diameter are drilled from the rig. A drill bit, attached to the drill

string suspended from the rig's derrick, is rotated in the well. Drill collars are attached to add weight and drilling fluids are circulated through the drill string and pumped through the drill bit. The fluid has a number of functions. It imparts hydraulic force that assists the drill bit cutting action, and it cools the bit, removes 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. When the reservoir is reached the well may be completed and tested by running a production liner and equipment to flow the hydrocarbons to the surface to establish reservoir properties in a test separator.

Field Development and Production

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.

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.

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.

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.

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.

Decommissioning and Abandonment

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 and removed. Other components, such as flowlines and pipelines, are often left in place to avoid environmental disturbances associated with removal. 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.