HSE

Health and Safety Executive

HID Inspection Guide Offshore

Inspection of Loss of Containment (LOC)

Contents

Summary

This guidance outlines ED-Offshore's approach to inspection of loss of containment risk, and in particular those elements which its process integrity team takes the lead on. It describes a number of key elements which contribute to effective management of the risks, based on research into route causes of previous incidents. It also identifies relevant legislation, technical standards and guidance, and criteria for performance assessment, against which duty holders' performance will be rated. References are made to technical standards and guidance that inspectors will use to form opinion for legal compliance. Areas where specialist support may be useful and necessary are also identified. It is important to note that the guide does not cover a number of aspects which are fundamental to management of loss of containment risk, but for which the technical lead is taken by other HSE specialist teams (e.g. mechanical integrity and materials and corrosion).

Introduction

The aim of this Operational Guide (OG) is to provide information and guidance to offshore inspectors to support the delivery of consistent and effective inspection of process safety systems which protect against loss of containment. It does this by highlighting current key areas to be covered during inspections, providing a framework for inspectors to judge

compliance, assign performance ratings, and decide what enforcement action to take should they find legislative breaches. In doing so, it complements HSE's Enforcement Policy Statement (EPS) and Enforcement Management Model (EMM).

Various regulations (described more specifically later) place duties on operators of offshore installations to take measures to minimise the risk of a loss of containment of flammable, toxic or hazardous substances. These measures must be effective throughout the installation's lifecycle, and under all foreseeable plant conditions
.
This guide is split into nine core intervention areas as follows:

1. Process Plant design, construction and commissioning processes
2. Process Plant operation within safe limits
3. Instrumented Protection Systems
4. Relief, Blow-down and Flare systems
5. Process Isolation Standards
6. Permits to Work
7. Management of small bore tubing, piping and flexible hoses
8. Management of change
9. Other Offshore Process Hazards

An overview of each of the above will be provided in the appendices 1-9.

The effectiveness of the measures taken under each area is key to ensuring that a duty holder minimises the likelihood and consequences of a major accident hazard occurring.

Action

A complete inspection of this topic requires all nine intervention areas to be addressed, although some may be of greater relevance to a particular installation given its inherent hazards, performance history and position within its own lifecycle. For the purposes of assessing the performance of a duty holder, the scope of the intervention areas to be inspected should be agreed in advance between the IMT and Process Engineering specialist inspectors. Individual appendices provide detail on relevant standards and good practise that are expected in general terms, but Inspectors will need to devise suitable question sets and other inspection approaches to assess the level of compliance against the quoted benchmarks, based upon the scale and nature of hazard at particular installations.

Background

ED-Offshore's main concern is the prevention of major hazard incidents, in which many workers are killed or injured. Major fires and explosions, such as occurred at Piper Alpha and Macondo, have been initiated by releases of hydrocarbons. As such, the effective design and implementation of measures to prevent such losses of containment is fundamentally important.

Typical sources of hydrocarbon releases (HCRs) are the well, the pipeline riser, other pipelines and pipe work and associated process plant. Releases can occur from either failure of the asset itself due to corrosion, abrasion or fracture, or because of failures of

maintenance e.g. poor practice when breaking and re-making joints, or insufficient operational controls. HCRs can also result from damage due to other failures e.g. dropped objects during crane operations.

Organisation

Targeting

Inspections should be planned within the timescales set out by ED divisional management. Although inspections may be carried out at any installation, it is particularly important to carry this out where there are known issues that may affect process integrity, such as aging equipment, major work over projects etc. It is essential to ensure that duty holders are robust in their assessment of the implications of these factors and that suitable mitigations are in place and that cumulative risk factors have been considered.

Timing

Inspectors should undertake loss of containment interventions as part of the agreed ED offshore intervention plan, when intelligence indicates intervention is necessary, or when investigation due to incident is required.

Resources

Resource for undertaking loss of containment interventions will primarily come from ED 3.1 Process Integrity Specialist Inspectors, and Inspection Management Team inspectors as appropriate. Several other topic areas, including Mechanical Integrity, Materials and Corrosion, Electrical, Control and Instrumentation, and Human and Organisational Factors also have a key role in assessing aspects of loss of containment risk however, and may take the lead on inspecting duty holder arrangements for these.

Recording & Reporting

The duty holder performance ratings should be entered on the Inspection Rating Form (IRF) tab of the relevant installation Intervention Plan Service Order. Findings should be recorded in the normal post inspection report and letter.

Further References

None

Contacts

Energy Division Unit 3.1 Process Integrity

Glossary

ACOP	Approved Code of Practice
DCR	Offshore Installations and Wells (Design and Construction, etc) Regulations 1996
DH	Duty holder
ESD	Emergency shutdown
ESDV	Emergency Shutdown Valve
FMEA	Failure modes and Effects Analysis
FPSO	Floating Production, Storage and Offloading Vessel
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability Study
HCR	Hydrocarbon Release
HIPS	High Integrity Protection System
HSWA	Health and Safety at Work etc. Act 1974
ICP	Independent Competent Person
LOPA	Level of Protection Analysis
MAH	Major Accident Hazard
MAR	Offshore Installations & Pipelines Works (Management and Administration) Regulations 1995
MHSWR	Management of Health and Safety at Work Regulations 1999
NUI	Normally Unattended Installation
ORA	Operational risk assessment
OSD	Offshore Division
PFEER	Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995
PSR	Pipeline Safety Regulations 1996
PSSR	Pressure Systems Safety Regulations 2000
PTW	Permit to work
PUWER	Provision and Use of Work Equipment Regulations 1998
QRA	Quantified risk assessment
SBT	Small bore tubing
SC	Safety Case
SCE	Safety critical element
SCR	Offshore Installations (Safety Case) Regulations 2005
SIL	Safety integrity level
SMS	Safety management system
SSIV	Sub Sea Isolation Valve

Appendix 1 - Process Plant design, construction and commissioning

Design

It is during the design stage of any process equipment, that there is the greatest potential for reducing loss of containment risk, through application of the principles of inherent safety. Design in this context covers the period of concept selection through to detailed design specification [drawings, calculations, specifications, etc.] It includes for example the consideration of avoidance of offshore processing [process onshore], inventory minimisation, segregation, complexity reduction, provision of separate accommodation, etc.

A number of principles should be adopted:-

- Risks implicit in the design should be identified
- Engineering design should use a hierarchical approach to minimise risk (avoid, substitute, reduce, adapt, technical controls, procedural controls, and measures which protect groups over those which protect individuals)
- Appropriate industry standards should be used
- Equipment that is safety critical should be capable of maintaining its integrity throughout its life, taking account of normal as well as foreseeable extreme operating loads
- The materials used should be suitable
- Active safety features should have adequate reliability, availability and survivability

Process risks, and loss of containment scenarios in particular, should be identified via installation specific hazard studies. These should be carried out in accordance with recognised standards or codes of practice, and include a detailed HAZOP study. Additional studies such as an 'HP / LP interface' review or 'Safety Analysis Function Evaluation' review in addition to HAZOP may also be appropriate. The outputs of such studies should be a full recording of the assessments made, rather than just a record of any issues or actions arising. This should support a demonstration that the process has been thorough, and ensure that any assumptions or bases are made clear.

Specific applications of inherent safety in design are described in the relevant appendices. For example in the case of over-pressure hazards, inherent safety implies that installations should preferably be designed to have fully rated risers, vessels, pipework and pipelines. If the topsides are not fully rated, a hierarchy of over-pressure protection measures should have been considered: full flow relief; partial relief with instrumented protection system; HIPS, etc. These areas are covered under appendices 3 and 4.

The mechanical design of vessels, pipework, pipelines and ancillary equipment also has a critical impact on loss of containment risk. This area is currently outside of the scope of this guide, but includes consideration of topics such as corrosion, erosion, fatigue/vibration, brittle fracture, rotating equipment seal design, bolted joints, mechanisms of aging/degradation etc. Design measures are numerous, and include approaches such as appropriate selection of materials (use of corrosion resistant alloys, low temperature resistant metals), minimisation of flanges through use of all-welded pipework, minimisation of the use of small bore tubing, minimising use of insulation (corrosion under insulation risk) etc.

Relevant industry standards are referenced under the subsequent appendices of this guide.

The topics of design, maintenance and verification of safety critical elements, the selection of materials, and the reliability, availability and survivability of safety features are in general outside of the scope of this delivery guide , although specific aspects of these where they particularly important to loss of containment risk may be referenced in individual appendices.

Supporting Standards/ACoP or Guidance

Inherent Safety in design:-

- ISO 13702:1999 - Petroleum and natural gas industries -- Control and mitigation of fires and explosions on offshore production installations -- Requirements and guidelines
- Energy Institute publication - Guidance on applying inherent safety in design: reducing process safety hazards whilst optimising CAPEX and OPEX.
- Oil & Gas UK publication HS088 - Guidance on Risk Related Decision Making
- Energy Institute publication HS007-Guidelines for the management of safety critical elements

Recognised standards/codes of practice for HAZOP include:

- HAZOP: Guide to Best Practice – I.Chem.E 2000
- IEC 61882 Guide for Hazard and Operability Studies (HAZOP Studies)
- CIA 1977 A Guide to Hazard and Operability Studies (relevant to older installations only).

Other recognised techniques for hazard identification and assessment include:-

- Failure Modes and Effect Analysis (relevant standard IEC 60812 – Procedures for Failure Modes and Effects Analysis)
- Fault Tree Analysis (relevant standard IEC 61025 – Fault Tree Analysis)
- SAFE (Safety Analysis Function Evaluation) Charts using EN/ISO 10418 (formerly API RP 14C) methodology
- BS EN ISO 17776:2002 – Guidelines on tools and techniques for hazard identification and risk assessment

Management Systems for construction, commissioning and start-up

There should be a project safety plan, and all personnel, including third parties, should have been made aware of the overall aims of the project and how health and safety aspects are integrated into the plan.

Safety Management System (SMS) interfaces should have been clarified. If more than one SMS applies, measures should be in place to ensure that there are no conflicts and that all relevant information has been effectively communicated to all parties.

Responsibilities should be clearly assigned. Where projects involve the installation and commissioning of vendor packages there can be a breakdown of responsibilities if this is not adequately controlled. E.g. where vendor packages are assembled and pressure

tested onshore then partially disassembled for shipment, the parties involved may include vendor package, project, hook-up contractor, and maintenance and operations personnel.

A procedure should be in place for controlling changes arising from construction and commissioning.

A structured mechanism for risk assessment should be in place. Risk assessment procedures, relating to construction & commissioning activities, should have been made available to all relevant parties, and risk assessments should adequately reflect potential consequences. Lessons learned from incidents during similar activities should be discussed during risk assessments and be an important part of the project safety plan.

Supporting Standards/ACoP or Guidance

- MHSWR Reg. 3, requirement for suitable and sufficient risk assessment.
- MHSWR Reg. 4, requirement to apply principles of prevention.
- MHSWR Reg. 5, requires a record of arrangements for planning, organisation, control, monitoring and review of preventive and protective measures.
- MHSWR Reg. 10, requires provision of comprehensible and relevant information.
- MHSWR Reg. 11, requires cooperation and coordination between employers.
- OGP publication - HSE Management - guidelines for working in a contracting environment - Report no.423

Pre-construction

A study of all potential hazards, arising out of the construction phase, should have been carried out (e.g. analysis of activities such as lifting adjacent to or over, live process plant). Procedures should have been developed covering precautions required for these. If more than one SMS applies, effective measures should be in place to ensure that there are no conflicts and that relevant information has be effectively communicated to all parties.

Construction

Systems should be in place for:-

- Competence assurance of individuals installing all safety critical equipment, such as piping, tubing, instrumentation and other protective systems. This may include the retraining / testing of personnel.
- Identification of critical flange joints and small bore fittings
- Recording of torque / tension settings and joint tagging for critical joints
- Independent checking of the assembly of critical joints to confirm correct use of joint materials, fasteners, flange condition, joint compression, and pipework alignment
- Management and control of change from design, arising during the construction phase. Modifications such as re-routing pipework around obstructions, or tie-ins into existing plant at different locations from the design, or altering the elevation/location of a PSV (which could affect draining of the discharge line into the flare header) would be typical of those, which may bypass procedures, and it is essential that there is awareness of the risks and required assessment process by construction personnel.

Supporting Standards/ACoP or Guidance

- MHSWR Reg. 3, Requirement for suitable and sufficient risk assessment.
- LOLER Reg. 8, Organisation of lifting operations.
- PUWER Reg. 4, work equipment has to be constructed or adapted as to be suitable for the purpose for which it is used or provided.
- PUWER Reg. 8, provision of information and instructions.
- PUWER Reg. 9, provision of adequate training.

Commissioning

This phase includes activities such as cleaning / flushing, drying, pressure / leak testing, and function testing.

Commissioning procedures should have been produced and made available to all relevant parties.

A project document control system should cover the approval, distribution and checking of project documentation, to ensure all parties are able to work with the most up to date version at all times.

Process pipework and vessels should be cleaned / flushed to remove debris (scale, slag etc.).

Flushing processes are normally carried out using a high volume flow of a compatible fluid, such as fresh water, but special fluids such as hydraulic oil for a hydraulic system, may be used so as not to contaminate the system with water. Where seawater is used for flushing it should be inhibited as required. Some systems, e.g. stainless steel, may require fresh water flush, following seawater, to remove chlorides.

Following water flushing, the system is drained at low points; residual water may be blown out of the system using dry air. Where the system is to be left empty for more than a few days, it should be blanketed with dry air or nitrogen to prevent internal corrosion. For prolonged periods in this state, the system may need to be treated with corrosion inhibitor.

Procedures should be in place to control pressure / leak testing. Wherever practicable, hydraulic testing should be employed to reduce the risks to personnel.

Strength testing is carried out to prove the quality of materials and the construction of the equipment / system before it enters service. Test pressure is typically 1.25 - 1.5 x system design pressure. All temporary connections must be adequately rated for the test.

Pneumatic leak testing is normally carried out at relatively low pressure (not exceeding 10% design pressure; normally ~2 barg) to identify leaks prior to hydrostatic testing or reinstatement testing at higher pressures. Testing with soap (or proprietary) solution, or inert gas with tracer (usually helium) is commonly carried out. The methodology for performing the leak test should be defined, including aspects such as:-

- suitable locations and equipment for applying the test pressure
- choice of test fluid
- consideration of requirements for pressure relief

- systematic recording of which joints have been inspected, and the method of checking for leaks (what constitutes pass/fail?)
- safe means of venting the pressure and disconnection at the end of the test.

Function testing may be carried out using a suitable test medium at design pressure, or working pressure if this is lower. The testing should check the function of components including the actuation of moveable parts, and successful activation of instrumented protective systems. Function testing should be planned, with acceptable test criteria defined, and records of its completion made. Sign-off of the results, by an appropriate level of management, should be required.

A system should be in place to identify faults arising during construction and commissioning phases, and track them to completion. 'Punch-lists' are normally used to collate such problems, prioritize corrective actions, and ensure that they are resolved to an appropriate timescale. Punch list items are typically prioritised according to the phase of the project by which they need to be resolved (e.g. before construction to commissioning handover, before leak test, before function test, before start-up, within 1 month of start-up etc). It is essential that project processes ensure that commissioning activities do not progress to the next phase, until all relevant punch-list items have been completed. Loss of containment events have arisen as a result of failure to effectively manage punch-list items, either in the period leading up to start-up (e.g. leak test not completed/thorough), or even some months later (e.g. damaged or missing insulation, or failure to plug or blank off open ends of small bore pipework). The risk is that some punch-list items are perceived to be a low risk, and consequently not progressed in a timely manner.

For vendor packages, it is beneficial for operators and technicians to gain familiarity with the equipment, by becoming actively involved in the commissioning, working alongside the vendor's personnel. Without this involvement the risk is that packages are handed over to installation personnel who have only limited practical knowledge of how to maintain and operate them.

Supporting Standards/ACoP or Guidance

- "Safety in Pressure Testing", HSE Guidance Note GS4 (3rd ed. 1998).
- EN 13445 (replacing BS 5500), ASME VIII Div.1, ANSI B31.3 (topsides pipework) cover pressure testing of process equipment.
- PUWER Reg. 8, provision of information and instructions.
- PUWER Reg. 6, requirement to inspect work equipment after it has been installed and put into service for the first time, or after assembly at a new site or location. Requirement to keep records of inspection.
- PUWER Reg. 12, protection against specific hazards. Cleaning, flushing and pressure testing contribute to the overall scheme of taking measures to prevent the unintended discharge of fluids from the work equipment.

Pre start-up phase

HAZOP and / or other safety studies should be carried out at the design stage. These should be formally recorded with lists of resulting actions (where necessary). Action lists

should be produced and an action tracking system set up. All actions should be closed out (i.e. completed & signed off) at an appropriate stage in the project lifecycle.

For additions to existing process plant, it is important that all factors affecting the existing plant have been identified and addressed.

Relevant operating procedures (new & revised), resulting from the project, should have been developed, reviewed, approved and formally issued in advance of commissioning. Where there have been additions, or modifications, to existing process plant, procedures should be updated to reflect the changes.

Adequate arrangements should be in place for the training of operators & technicians. Training can commence when the design has been fixed (i.e. approved for construction) and operating procedures become available.

Supporting Standards/ACoP or Guidance

- MHSWR Reg. 3, requirement for suitable and sufficient risk assessment.
- PUWER Reg. 4, work equipment has to be constructed or adapted as to be suitable for the purpose for which it is used or provided.
- PUWER Reg. 8, provision of information and instructions.
- PUWER Reg. 9, provision of adequate training
- API RP 14C / BS EN ISO 10418, Basic surface process safety systems

Appendix 2 - Process Plant operation within safe limits

Fundamental Requirements

Safe operating limits should be specified for pressure, temperature, level and flow, and other parameters that may be applicable, such as process composition, for all parts of the process topsides equipment.

Documentation should be available to technical authorities and operating staff to enable the plant to be operated within its designed safe operating limits. Documentation may include:-

- Process Flow Diagrams
- Piping and Instrumentation Diagrams
- Equipment data sheets
- Vendor data sheets and specifications
- Piping specifications
- Instrument data sheets
- Cause and Effect Diagrams
- Register of alarm and trip settings
- Operating Procedures

Safe operating limits need to be easily accessible to operating staff (e.g. within written instructions, DCS system), and a system be in place to ensure that records of the limits are maintained as controlled documentation.

Instructions should be provided which:-

- reference the values of the safe operating limits
- explain the reasons for them and the potential consequences of exceeding them
- explain what corrective actions should be taken to return to within safe limits. Where there is uncertainty or doubt about the safe or stable operation of the process plant, it should always be taken to its safest state.
- explain how excursions outside of limits should be reported to management, investigated and addressed

Safe operating limits, and instructions which reference them, should be regularly reviewed by staff with an understanding of the design basis of the process plant, and the manner by which it is being operated. Good practice would be to do so every 2-3 years. As well as periodic reviews, reassessment of the limits and instructions should be triggered by modifications to the process, whether they be as a result of deliberate changes (e.g. installation of new equipment, tie-ins or wells), or gradual changes to the process conditions (e.g. increasing water cut).

Systems should be in place to monitor and ensure that operating procedures are being followed, and safe operating limits adhered to. Deviations from safe operating limits should be recorded, investigated, and action taken to address the root causes.

Appropriately designed, instrumented and mechanical, protective systems should be in place to prevent (or reduce the risk as far as reasonably practicable) operation outside or

safe operating limits. See appendices 3 & 4. Demand rates on these systems should be monitored.

Supporting Standards/ACoP or Guidance

- DCR Reg. 7 requires the duty holder to ensure that the installation is not operated unless appropriate limits within which it is to be operated have been recorded.
- PUWER Reg. 8 requires employers to ensure that all persons who use work equipment have … adequate health and safety information and, where appropriate, written instructions.
- PSR Reg 11 requires operators to ensure that no fluid is conveyed in a pipeline, unless the safe operating limits of the pipeline have been established, and the pipeline is not operated beyond its safe operating limits
- PSSR Reg. 7 requires the user to establish the safe operating limits of a pressure system (N.B. PSSR is not applicable offshore but may be used to illustrate good practice)
- API RP 14C / BS EN ISO 10418, Basic surface process safety systems

Appendix 3 - Instrumented Protection Systems

Introduction

Instrumented Protection Systems (IPSs) are often employed to provide protection against vessels or lines being subjected to over-pressures. Typically such systems will be used in combination with other forms of pressure protection such as mechanical pressure relief valves. However in some cases an IPS provides the sole means of protection. Whatever the duty an IPS will typically comprise a sensor or sensors to measure the internal pressure of the vessel or line, electronic signal processing & logic and actuator(s) and valve(s) to effect the final action such as line shut-off or vessel venting. Good practice is for an IPS not to require any operator response for its normal operation.

Other forms of IPS which provide or contribute to protection against loss of containment may be encountered.

IPSs may also be referred to as Safety Instrumented Systems (SISs), High Integrity Pressure Protection Systems (HIPPS), Trips, Interlocks or Instrument-Based Protective Systems.

Alarms may be provided to alert operators that process variables are reaching the limits of normal operation, thereby providing the opportunity for operators to make corrections to the operation of the plant before an IPS trip level is reached. Alarms are typically implemented in the plant process control system and so are not subject to the same requirements as an IPS.

Scope

This inspection guidance applies to Instrumented Protection Systems providing, in part or in whole, protection against loss of containment from offshore oil or gas production process plant and pipelines. It includes inspection of such systems whether located on offshore installations or subsea.

It also provides guidance for the inspection of process control alarm systems.

Industry Standards and Guidance

The principal industry standards that apply to Instrumented Protection Systems are IEC 61508 (ref 1) and IEC 61511 (ref 2). Both of these standards are published by BSI as European Standards (BS EN 61508 and BS EN 61511) although they are not harmonized under any European Directive. HSE has contributed substantially to the development and maintenance of these standards. IEC 61508 is a generic standard which can be applied to Instrumented Protection systems in any application whereas IEC 61511 applies to the process industry sector. The underlying technical principles of these standards are very similar.

Industry guidance to the application of IEC 61511 was developed jointly by EEMUA, EIC and Oil and Gas UK (ref 3). HSE also contributed to the development of this guidance. This supersedes the UKOOA Guidelines of Instrument-Based Protective Systems.

IEC 61508 and IEC 61511 encompass the full lifecycle of Instrumented Protection Systems from initial concept through specification, design and installation to 'in service' use and maintenance and eventual decommissioning. They address hardware, software and management aspects and apply to the overall Instrumented Protection system from sensor(s) to final elements. The standards define the concept and application of 'Safety Integrity Levels' (SILs) as a measure of the integrity of Instrumented Protection systems and as a basis for grading the hardware reliability and rigour of measures for the avoidance and control of faults.

Relevant HSE guidance

The following relevant HSE inspector guidance is applicable:

- Management of instrumented systems providing safety functions of low / undefined safety integrity, HID SPC/Technical/General/51 (ref 4)
  This is HID's guidance for inspectors on the management of systems which have a low integrity requirement and so are not SIL rated (sometimes referred to in the industry as 'SIL 0').

- Proof testing of safety instrumented systems in the onshore chemical specialist / industry, HID SPC/Technical/general/48 (ref 5)
  This is HID's guidance for inspectors on the proof testing of safety instrumented systems. The technical requirements are equally applicable offshore.

- Safety instrumented systems for the overpressure protection of pipeline risers, HID SPC/Technical/OSD/31 (ref 6).
  This is HID's guidance for inspectors on safety instrumented systems for the overpressure protection of pipeline risers on offshore installations (eg HIPPS).

- Operator Response within Safety Instrumented Systems in the Chemical (Onshore), Oil and Gas (Offshore), and Specialist Industries, HID SPC/Technical/general/50 (ref 7)

- Managing competence for safety-related systems, Part 1 – Key Guidance and Part 2 – Supplementary Material (refs 8 and 9).
  This industry guidance was jointly developed and issued by HSE, the Institution of Engineering & Technology and the British Computer Society. It sets out expectations for the management of personnel competency at all stages of a safety-related system's lifecycle.

Relevant Statutory Provisions

- Under OSCR (ref 11) Regulation 19 – Verification schemes – the Duty Holder must ensure that a record of the safety-critical elements and the specified plant is made. This record should include Instrumented Protection Systems (IPS), the purpose of which is to prevent or limit the effect of a major accident on the installation being inspected. Under section 3 of the Health & Safety at Work etc.

Act it should also include any IPS that provides protection for another installation. It is to be expected that any such IPS should be rated in terms of Safety Integrity Level (SIL) or equivalent (eg Shell IPF Class). Any IPS(s) should be included in the verification scheme and so subject to periodic examination by the independent competent person.

- PFEER (ref 12) Regulation 9 requires the Duty Holder to take appropriate measures with a view to preventing a fire and explosion including such measures to a) ensure the safe production, processing …… b) prevent the uncontrolled release of flammable or explosive substances.

- PFEER (ref 12) Regulation 5 requires the duty holder to identify the various events which could give rise to a major accident involving fire and explosion, to evaluate the likelihood and consequences of such events, establish appropriate standards of performance and select appropriate measures.

- PFEER (ref 12) Regulation 19 requires the Duty Holder to ensure all plant on the installation …is so constructed or adapted to be suitable for the purpose for which it is used or provided and is maintained in an efficient state, in efficient working order and in good repair.

- PUWER (ref 13) Regulation 18 requires the employer to ensure, so far as is reasonably practicable, that all control systems of work equipment are safe, are chosen making due allowances for the failures, faults and constraints to be expected in the planned circumstances of use. A control system shall not be safe unless its operation does not create any increased risk to health or safety and unless it ensures so far as is reasonably practicable that any fault or damage to any part of the control system or the loss of supply of any source of energy used by the work equipment cannot result in additional or increased risk to health or safety.

Inspection Guidance - Instrumented Protection Systems

Verify that all IPSs are declared as Safety Critical Elements.

The relevant standards (refs 1 and 2) require that there should be a Functional Safety Assessment (FSA) for all SIL rated IPS. The FSA should be carried out by a team including the technical, application and operations expertise for the installation being inspected and should include at least one senior competent person not involved in the project design team. It should provide a judgement as to the functional safety and safety integrity achieved by the IPS(s). Verify that an FSA in accordance with IEC 61508 or IEC 61511 has been carried out for any IPS. A competent FSA will provide evidence that the IPS(s) have been specified, designed, installed and commissioned in line with the relevant standards.

An IPS commissioned prior to the publication of the relevant standards may not have an FSA. In such cases it is to be expected that the duty Holder has undertaken a gap analysis to determine the extent of deviation from current good practice and put in place an action plan to bring such systems into line with IEC 61508 or IEC 61511.

Note that the above may be best accomplished by reference to the Duty Holder's technical/engineering support onshore prior to the offshore inspection.

The Duty Holder should be asked to demonstrate that proof test procedures are in place for every IPS and that there is evidence that the procedures have been carried out. The procedures should ensure that all elements (including all elements in redundant configurations) of an IPS are periodically tested at a frequency as specified by the IPS designer. The procedures should provide clear instructions and should ensure that all critical aspects of performance (eg closing time of a fast acting HIPPS valve) are tested so that any faults which are not apparent during normal operation are revealed.

The Duty Holder should be asked to provide records which detail how frequently operating demands have been placed on every IPS. This should be checked against the specifications from the IPS designer(s).

The Duty Holder's arrangements for management of IPS overrides/ inhibits/bypasses should be inspected. A comprehensive record of all inhibits/overrides/bypasses should be maintained. Inhibits/overrides/bypasses should only be applied subject to a documented risk assessment (ORA) and should be removed when no longer needed. Valve bypasses should be locked closed in normal service. Where there is more than one control location a proper protocol for override/inhibit management should be in place.

The Duty Holder's arrangements for control of all IPS software and configuration settings (eg cause and effect logic, trip settings, system software) should be inspected. There should be effective change control procedures requiring appropriate management authorisation for all changes, and evidence of their application.

When operators form part of a SIL rated IPS the Duty Holder should demonstrate that the requirements for making high human reliability claims as set out in SPC/Technical/General/50 (ref 7) have been achieved.

Inspection Guidance – Alarm Systems

Verify that the Duty Holder has an alarm design and management strategy that takes account of the guidance in the EEMUA Guide to Alarm System Management and Procurement (ref 9).

Specialist Advice

Where deficiencies are evident relating to this Inspection Guidance, HID ED3.5 should be consulted for further advice.

References

1. IEC 61508:2010 Functional safety of electrical/electronic/programmable electronic safety-related systems (7 parts, also published as BS EN 61508)
2. IEC 61511:2003 Functional safety – Safety instrumented systems for the process industry sector (3 parts, also published as BS EN 61511)
3. Guide to the application of IEC 61511 to safety instrumented systems in the UK process industries, EEMUA 222

4. SPC/Tech/Gen/51 Management of instrumented systems providing safety functions of low / undefined safety integrity
5. SPC/Tech/Gen/48 Proof testing of safety instrumented systems in the onshore chemical / specialist industry
6. SPC/Tech/OSD/31 Safety instrumented systems for the overpressure protection of pipeline risers
7. SPC/Tech/General/50 Operator response within safety instrumented systems in the chemical (onshore), oil & gas (offshore), and specialist industries
8. Managing competence for safety-related systems, Part 1 – Key Guidance and Part 2 – Supplementary Material (HSE/BCS/IET 2007)
9. Alarm systems – A guide to design, management and procurement, 2nd edition, EEMUA 2007
10. Offshore installations (Safety Case) regulations 2005
11. Offshore installations (Prevention of fire and explosion, and emergency response) regulations 1995
12. Provision and use of work equipment regulations 1998
13. The Norwegian Oil and Gas Association Publication 070 – Guidelines for the application of IEC 61508 and IEC 61511 in the petroleum activities on the continental shelf

Appendix 4 – Relief, Blowdown, Vent and Flare Systems

Fundamental Requirements

The duty holder should have in place arrangements to prevent over- and under-pressure of process plant and equipment. Such extremes may lead to a rapid and uncontrolled loss of containment event. Pressure systems should ideally therefore be designed for maximum and, where relevant, the minimum anticipated operating pressure under all modes of operation. It needs to be borne in mind that the maximum operating pressure may not occur during the normal mode of operation.

Designing equipment and systems to the maximum pressure (or vacuum) to which it can be subjected can have advantages in simplifying plant by reducing or eliminating protection or relief systems. Where necessary, facilities should be protected with recognised relief devices discharging to suitable disposal or an instrumented high integrity protection system or a combination of both. All possible sources of overpressure need to be identified and allowed for.

A means of removing significant hydrocarbon inventories from equipment to a safe location should also be provided (blow-down). This can be used immediately following detection of a loss of containment, or pre-emptively if there is a risk of an adverse situation escalating in consequence.

Hydrocarbons arising from relief and blow-down events need to be safely conveyed to atmospheric vents or a flare for effective dispersion and disposal. The vent and flare system must be capable of handling credible combinations of upstream events, without compromising the ability of the protective devices to prevent over-pressure. The vent and flare systems must also not introduce other hazards such as excessive thermal radiation, or the potential to generate flammable mixtures within pipework.

The following sections describe in more detail the expected elements of control that are required:-

Relief and Blow-down system design and philosophy

- Relief device designs are documented, with assumptions on required relief rates, fluid conditions, and design methods/codes clearly recorded.
- Relief stream piping routes and sizing are assessed to ensure that the ability of the devices to prevent overpressure of upstream equipment is not compromised under all credible cases
- Incompatible fluids are segregated (e.g. cold streams / wet streams, or hot streams / condensate). Piping is designed to prevent slugs of liquid accumulating
- Relief stream designs are re-assessed in light of changing process conditions and duties to ensure they remain fit for purpose
- Where blow-down systems cannot handle simultaneous flow from all protected systems, suitably robust controls are put in place to enable phased operation
- Knock out drums should be sized to manage foreseeable relief events.

- The design of the relief and blow-down systems should be re-evaluated in the light of any additions of new equipment or changed operating conditions (e.g. well fluid composition change).

Relief and Blow-down operation

- Operating procedures should be in place for the relief and blow-down system, which specify routine checks of purge rates and that header drains are clear. They should contain guidance on whether to shut down, or continue operating, in all the circumstances that are likely to be encountered. A plan of action should be in place for high flare drum level.
- Routine tests should be performed on the operation of blow-down systems to confirm their effectiveness (time to depressurise, excessive vibration etc) under a controlled (non-emergency) situation. Credit can however be taken for analysis of real events provided the data is captured.
- A policy should be in place regarding the need for (or otherwise) of relief valve/pipework testing/overhaul following operation of a relief or blow-down system. Relief stream operation may lead to impairments to the relief stream components, such as bursting disc failure, relief valve seat damage, blockage/fouling. The likelihood of such damage will depend on the process system and fluids involved, as well as the design of the stream and the duration of the release.

Flare operation

- Arrangements (typically a nitrogen or fuel gas purge) should be in place to ensure that air ingress to the flare headers, leading to the formation of a flammable mixture, cannot occur. This should function under all installation conditions (particularly during start-up and shutdown where a source of fuel gas may not be available).
- Flare header drains need to be clear and not choked with debris, and rates of purge gas (if used) above safe minimum requirements. Both should be subject to regular operator checks
- Operating procedures should contain guidance on whether to shut down, or continue operating, in all the circumstances that are likely to be encountered on the flare system. In particular, a plan of action should be in place for high liquid level in the flare knockout drum, and flare restart following a shutdown
- A safe means of lighting the flare must be in place. A method of ensuring that the flare stack contents and any pilot systems are outside of the flammable mixture region to prevent flashback during lighting is required.
- Thermal radiation from the flare must not risk damage to personnel, through direct contact, or through knock damage to other installation equipment (including safety critical elements in particular)
- Toxic components within gases that are flared must be effectively destroyed, and the combustion products sufficiently dispersed so as not to risk harm to personnel.

HP/LP interface studies

- Risks of over-pressurisation at HP/LP interfaces must be identified, assessed, and controlled.

- Protection may be by mechanical relief or instrumented trips of adequate integrity. In some situations it may be by procedural or other means to prevent over-pressurisation, using locked valves, blinds, restrictor orifices etc. It is generally best to carry out a specific HP/LP interface study, separate from the more routine HAZOP procedure.

Supporting Standards/ACoP or Guidance

- API RP 520 Sizing, Selection, and Installation of Pressure-Relieving Devices
- API RP 521 Guide for Pressure-Relieving and De-pressuring Systems (ISO 23251)
- Institute of Petroleum - *Guidelines for the Safe and Optimum Design of Hydrocarbon Pressure Relief and Blow-down Systems* (ISBN 0 85293 287 1)
- PFEER Reg. 9 requires appropriate measures with a view to preventing fire and explosion. PFEER Reg. 12 requires appropriate measures to limit an emergency, including remote operation of plant.

Appendix 5 - Process Isolation Standards

Fundamental Requirements

The duty holder should have in place arrangements to manage the isolation of process plant and equipment, to ensure that the uncontrolled release of flammable/toxic substances to atmosphere cannot occur.

Process isolations are typically associated with temporary changes to the state of the plant such as during planned maintenance work, start-up, shut-down or re-commissioning activities. They may also be used to protect against particular over or under pressure hazards, and be of a short or long term nature.

Duty holders must ensure that the following elements are adequately addressed by their arrangements:-

Planning and preparation of tasks which require isolation

- Procedures should be in place describing how isolations should be managed, with appropriate training and competency assurance programmes for those with specific roles within the arrangements, and monitoring audit and review procedures.
- Hazards associated with isolated substances, and work tasks which may release them are identified.
- The likelihood and potential consequences of failure of tasks reliant on isolations are assessed, throughout the lifecycle of the isolations (installation, work task, removal and reinstatement)
- Isolation schemes are designed in accordance with an appropriate methodology, based on minimising the risk to ALARP (or positive isolation in the case of confined space entry)
- Planned isolation schemes are effectively documented and communicated to all who may be affected by them
- Higher risk isolations that do not meet any duty holder 'baseline isolation standard' should be subject to additional risk assessment and a greater level of management approval. This process should sufficiently identify the deviation from baseline standard, the associated hazard, and all reasonably practicable additional control measures to be put in place. Improvements to procedures/equipment to enable the baseline standard to be met in future should also be identified, assigned to appropriate responsible persons for design and implemented.

Installation of isolations

- A controlled sequence of activities is used to minimise risk during installation of isolations
- An appropriate standard of blanks/plugs/joints/spades/blinds and other fittings is used to effect isolations and secure closed any open pipework
- Installed isolation schemes are fully labelled, and cross-referenced to P&IDs or other suitable drawings, and work control documentation

Proving of isolations, control of work tasks, and monitoring

- Checks to ensure that isolations and other plant preparation activity have been effective in removing the identified hazards are in place
- Formal systems which communicate that effective isolation has been achieved, to allow tasks which rely on it to proceed, are in place
- Un-authorised/unintended removal of isolations is prevented
- Routine, recorded checks of the status of isolations and associated controls are in place, at a suitable frequency

Reinstatement of plant

- Following removal of isolations, visual and work control system checks are made to ensure that plant is returned to its 'as was' or intended status.
- The risk of a loss of containment on reintroduction of process fluids is minimised through application of an appropriate leak/proof testing policy.
- The hazards associated with start-up of equipment that has previously been shut-down/isolated are considered and appropriate controls put in place

Locked valve controls

- Process valves specified as locked open or locked closed as their normal operating mode should be clearly identified by name or number, on or near the valve, and on diagrams. Valves should be positively secured so that significant movement is prevented, for example by mechanical interlock, key switch or padlock and chain. If keys are used, access to them should be controlled. The reason for locking a valve should be known to personnel and specified in operating procedures.
- Locked valve status should be periodically checked, with the frequency taking into account the potential consequences of the valve being in the wrong position. More critical valves, such as any in ESDV vent lines, should be checked at least monthly. Valves should be identified on a readily available register, with details of each valve, its location and status, and the checks carried out, including the date, the person doing the checking and the results.
- The positions of isolation valves on inlets to safety critical instrumentation should be controlled. Routine test procedures should require the isolations to be returned to their normal position at the end of the activity, but there remains the possibility that such a step will be omitted. They are also often small, ¼ turn ball/plug valves, with a higher risk of being accidentally knocked closed by others working in close proximity to them.

Isolations for relief and vent systems

- Relief systems are required to be operational at all times when the plant is (or may become), pressurised. Where isolation valves are used, such as to allow maintenance to be done on a live system, for example when two relief valves are used in parallel, a system is required to ensure that one valve is always on line. This may be in the form of mechanical interlocks on the isolation valves on each relief valve branch, or other forms of locks provided there are effective procedures

to monitor the isolations. Interlocks should be appropriately located such that inappropriately rated lines cannot be over-pressurised.

- The use of interlock keys should be controlled, particularly if spare or master keys exist for maintenance purposes. Operating instructions for interlock systems should be available, with personnel trained in their use. Maintenance of the system is required, as keys and lock mechanisms can wear and keys can become misplaced.

Extended Isolations

- Where process equipment is isolated for extended periods of time (sometimes permanently) because it is not commissioned, redundant, only used infrequently or awaiting repair or modification, additional controls should be in place. These could include a register identifying all long-term isolations and the reasons for isolation, a procedure for checking the status and integrity of each isolation, and a system for periodic review of the status of each item, to decide if the isolation is still appropriate, if the plant should be removed, or if other action should be taken.

Supporting Standards/ACoP or Guidance

- HSG 253 'The safe isolation of plant and equipment'
- HSG 254 'Developing process safety indicators'
- HSWA s.2,3 requires the provision of safe systems of work…
- MHSWR Reg. 3 requires assessment of risks to health and safety
- PFEER Reg. 9 requires safe production, processing, etc. of flammable and explosive substances, and prevention of their uncontrolled release.
- PUWER Reg. 8 requires employers to ensure that all persons who use work equipment have adequate health and safety information and, where appropriate, written instructions

Appendix 6 – Permits to Work

Fundamental Requirements

A separate HID Inspection Guide Offshore for control of work has been published. This appendix is supplemental to that, and also emphasises important elements from a hydrocarbon release perspective. Such hazards typically arise from work on containment systems during construction or maintenance, and may involve the deliberate breaking of containment (or the potential to do so). The duty holder should have in place arrangements to manage the control of work via a permit to work system, which ensure that the following elements are adequately addressed:-

Policy and procedure

Any work involving breaking containment (or the potential to do so) on hydrocarbon systems, should require a permit to work ('PTW') and effective isolation and removal of stored energy/hydrocarbon hazard (see appendix 5). The only exceptions are where there is explicit and specifc authorisation and a written procedure to control the work by other means (such as under an emergency management procedure, or where the work is classed as low risk and part of an individual's routine activity, for which training has been provided, and competency assured). Work with the potential to break containment includes activities such as lifting of heavy loads over live process pipework, where a failure of the lift could give rise to a loss of containment through impact

Procedures should identify who needs to be involved in authorising breaking of containment work, and additional authority levels, permits or certificates may be appropriate for managing these.

Task Risk assessment

Effective dialogue should take place between the performing and authorising authorities to ensure that the planned work scope and associated hazards and necessary controls are understood. It is essential that the worksite is visited, and the equipment to be worked on located, its identification labelling checked, the break-in points agreed, and the worksite visibly tagged, to ensure that the risk of break-in to the wrong (potentially on-line) equipment is minimised. This is a particular risk where there are multiple plant items with similar name or function (e.g. dual stream pumps).

The working environment and workflow should support effective PTW preparation/issue. Ideally individuals should be able to plan, discuss and issue/accept PTWs away from noisy or sensitive environments such as workshops or process control rooms.

The PTW and associated documentation must be an effective tool for communication of the content of a task, and the hazards and control measures associated with it to anyone who requires it. The hazards and controls associated with a risk of loss of containment should have a high emphasis placed on them, relative to issues related to personal safety.

Task approval

Approving authorities must decide whether a task can be performed at an acceptably low level of risk. They must have:-

- sufficient time to carry out the assessment
- a proper understanding of the tasks to be authorised and their associated hazards
- a good understanding of
  - prevailing asset status
  - other live permits
  - the condition and availability of safety critical elements which may impact on the task
- an understanding of the control measures and their suitability

in order to be able to assess and approve tasks effectively. Approving authorities must indicate their (written) permission for a task to be performed before it goes ahead.

Task co-ordination, handover, suspension, hand-back and supervision

A clear overview of all live tasks on an installation (what, where, who) should be available so that the interactions of tasks on each other and the installation can be identified / assessed. A good understanding of these links is required, as computer based permit systems typically used to look for conflicts between PTWs typically rely on geographical based displays of live PTWs, rather than process system linked displays. Work on vents and drainage systems in particular need careful assessment, as these typically link across multiple other process systems.

Status information for PTWs should be accurate and readily available. Tasks that continue over subsequent shift periods should be safely controlled. New work teams should be briefed on the work, and appropriate handover and re-authorisation controls be in place.

A means of cancelling (or suspending) a PTW must be available, such as due to conflicting work priorities, or when the hazards associated with the task may have changed (e.g. due to environmental factors).

An effective means of hand-back of a permit, relinquishing the granted authority to perform the task, and communicating task/equipment status must be in place. This should ensure that where there are residual faults or deficiencies with equipment that has been worked on (which may compromise its ability to safely contain hydrocarbons), these are communicated, and controls to prevent the equipment being put back into service remain in force.

Appropriate supervision and monitoring must be in place to ensure that the PTW system and individual PTWs are being complied with

Monitoring and review of effectiveness of permit to work arrangements

Suitable measures should be in place to identify whether the permit to work arrangements are effective, and compliance with them is being achieved.

Supporting Standards/ACoP or Guidance

- HSG 250 Guidance on permit-to-work systems: A guide for the petroleum, chemical and allied industries
- HSWA s.2,3 requires the provision of safe systems of work…
- MHSWR Reg. 3 requires assessment of risks to health and safety
- MAR Reg 10 requires arrangements for securing that a person does not do…..work save in accordance with the terms of a permit in writing…

Appendix 7 - Management of small bore tubing, piping & flexible hoses

Management systems for small bore tubing

- The use of small bore tubing should be avoided where possible.
- The integrity of small bore tubing system should be addressed within the management system over its whole life cycle. Responsibility for carrying out policy should be allocated to technical authorities within the management system, and monitoring of the implementation of the policy included within the Technical Audit programme.
- An asset register of all small bore tubing systems should be maintained.
- Duty holders should have a formal scheme which ensures that all the personnel (company and contractor) required to work on small bore tubing systems are formally assessed as being competent to do so, including periodic reassessment.
- Management procedures should ensure that Vendor personnel employed on short term construction or maintenance work are competent to carry out such work
- A control and standardisation policy for the technical management and minimisation of small-bore tubing and fittings types should be developed, documented and implemented for each new and existing installation. This should include:-
  - preferred fitting and tube types per plant
  - the fitting and tube type per system or sub system
  - the planned fitting and tube type migration per system or sub-system
  - the strategy to minimize the inventory by design-out, refurbishment and ad-hoc maintenance activities
  - a company or installation directive for new and replacement systems to comply with the preferred equipment requirement
  - systems to ensure vendor compliance with the policy.
- On installations where several makes and types of tubing and fittings are already present, it may not be reasonably practicable to change all systems. In this case it should be demonstrated however that the range of fittings and tubes have been minimised to a manageable level, and that personnel competencies are consistent with the residual inventory.

Small bore tubing maintenance and operational procedures

- Procedures should be available which include how to carry out:-
  - checks of the overall integrity of the system
  - visual inspection of compression fittings for correct component selection and correct make-up (with use of manufacturer's gauge as applicable)
  - sample disassembly of compression fittings to check for correct make-up, tube penetration and internal corrosion of tube and clamp
  - examination of support and mounting for vibration control
  - check to identify possible problems with maintainability, i.e. access, corrosion, ease of removal etc.
  - response to process leakage or seepage from compression joints and pipe thread connections
  - pressure/leak testing of systems which have been subject to extensive disconnection or involves the installation of untested fabricated equipment,

as well as individual impulse lines which have been subject to minor disconnection.

- Adjustment and rework should not be permitted on systems whilst pressurised or not adequately isolated
- It should not be permissible to interchange sub-components of different designs or types of fittings
- The installation and assembly of particular types of small bore tubing and fittings must be made in accordance with the manufacturer's instructions. (Note: these can be different between manufacturers and between fitting sizes of the same manufacturer)
- It is essential that fitting is inspected on completion using gauges where available or by other methods recommended by the manufacturers
- Appropriate tools should be defined and used and special tools, such as hydraulic swaging machine should be considered for fittings of larger sizes of fittings and tubing.

Vibration and supporting of small bore tubing

- The DH should have a structured assessment methodology in place for identification and management of vibration related risk to small bore tubing. Systems with the following possible excitation mechanisms should be identified:
    - flow induced turbulence
    - high frequency excitation
    - mechanical excitation
    - pulsation
- Systems identified to have a problem should be further analysed to determine the likelihood of failure. Where this is significant, the features of the small bore pipe and its connection to the main pipe should be reviewed, and where possible changes made to the design to reduce the risk. Important features include
    - type of fitting (i.e. weldolet, contoured body, short contoured body etc.)
    - length of branch
    - number and sizes of valves
    - main and small bore pipe wall thickness (schedule)
    - small bore connection diameter
    - location of small bore pipe on the main pipe.
- Potential design solutions include:-
    - reducing the overall and unsupported length of the fitting
    - reducing the mass of unsupported valves / instruments
    - ensuring the mass at the free end of a cantilever pipe assembly is supported in both directions perpendicular to axis of the small bore
    - arranging supports from the main pipe, to ensure that the small bore connection moves with the parent pipe
    - maximising the diameter of small bore connections
- Tube support should be provided as per manufacturer's instructions to prevent unacceptable stresses on fittings e.g. eliminate sagging and vibration.
- Valves, gauges etc. should be independently mounted. Expansion loops should be provided as per design. Tube support material should be as per design specification.
- Tube systems should be adequately supported as necessary when connections are being tightened or uncoupled

Isolation practices and standards

A primary isolation valve (piping standard) should be located close to the pipe or vessel, and be to the same standard of pressure integrity. Instrument connections beyond the primary isolation facility are sometimes less robust than the primary connection e.g. compression fitting may be used in the impulse tubing and the instrument may use components such as flexible hoses or sight glasses.

Instruments will generally be provided with local isolation facilities that, together with the primary isolation, can provide a double block and bleed isolation. Drain, vent and test points should be provided with valves to close them off when not in use.

Management of flexible hoses

- The use of flexible hoses should be avoided where possible, in preferences to permanent hard-piped systems.
- Duty holders should ensure that integrity of small bore flexible hoses used on hydrocarbon/hazardous processing plant is addressed within their management system. Elements should include consideration of design, risk assessment, construction, installation, commissioning, operation, maintenance, testing, modification and decommissioning.
- An asset register of flexible hoses should be maintained.
- Persons responsible for hose selection, maintenance or use should be suitably competent and aware of safety critical factors affecting hose integrity through an understanding of hose constructional elements and their function in maintaining integrity, failure modes, failure criteria, etc.
- Hose assemblies should only be used in hazardous duties where permanent piped solutions are not suitable or do not offer a safer alternative solution. Hoses should be classified according to the consequence of failure.
- When deciding upon the performance and safe operational requirement of a hose, parameters for consideration include:-
    - compatibility of inner liner material with the media to be carried
    - compatibility of outer cover with working environment
    - flow requirements
    - pressure and temperature range
    - the operational environment - length, flexibility and bend radius
    - weight, compactness and support requirements
    - volumetric expansion, movement under loading
    - compatibility of hose with end fittings, and fitting compatibility with media and operational environment
- All hoses in critical service applications should be examined on a regular basis, to assess their suitability for continued service. Inspection frequency and criteria should be developed from the risk assessment derived from the classification process.
- Hoses and their fittings should be visually examined for physical damage against defined criteria including: (a) blisters or bulges (b) looseness of the outer cover (c) excessive softening or hardening of the hose (any of these three points may indicate fractured or displaced reinforcement or a leaking liner) (d) kinks, twists (poor installation) (e) abrasion, cuts, excessive elongation under load or test (f)

end coupling integrity. Any hose exhibiting cover cracks, cuts or bulges should be removed from service, examined and retested as necessary. Any hose with reinforcement exposed should be removed from service and replaced if extent of damage exceeds manufacturer recommended limits. If in doubt, hoses displaying visible faults should be replaced.
- Pressure testing should be carried out in compliance with relevant vendor's procedure. Records of visual examination should be kept, recording the condition of the hose on a particular date and the date of next inspection. The hose should be tagged with the latest inspection date and the date of next inspection.

Supporting Standards/ACoP or Guidance

- Institute of Petroleum / Oil and Gas UK "Guidelines for the Management, Design, Installation and Maintenance of Small Bore Tubing Systems" (ISBN 0 85293 275 8)
- Energy Institute publication "Guidelines for the Avoidance of Vibration Induced Fatigue in Process Pipework" 2nd Edition, 2008.
- Energy Institute publication "Guidelines for the management of flexible hose assemblies"
- PUWER Regs 3,4,5,6,8 and 9 require employers, and duty holders (Reg. 3), to ensure:
    - Work equipment is constructed or adapted so as to be suitable for the purpose for which it is provided (Reg. 4); work equipment is maintained in an efficient state, efficient working order, and good repair (Reg. 5); where work equipment is of a type where safe operation is critically dependent on it being properly installed, (or reinstalled) the equipment is inspected before being put into service, and at suitable intervals (Reg. 6); people who use work equipment have adequate health and safety information, and written instructions (Reg. 8); all persons who use work equipment have received adequate training (Reg. 9). PFEER Reg. 5 and 9, and MHSWR Reg. 5 are also relevant.
- SCR requires safety critical elements to be verified by independent competent persons. This may include flexible hose assemblies.
- Pressure Equipment Regulations 1999 (PER) applies to fixed installations between well and pipeline, for equipment installed by the manufacturer, which may include flexible hose assemblies. PER does not apply to mobile offshore drilling units (MODUs) and equipment assembled under the responsibility of the user, including well control equipment and pipelines.

Appendix 8 - Management of change

Many of the catastrophic events that have occurred on process facilities are attributable to changes. There have also been numerous deficiencies in offshore process systems arising from the failure to control change.

A typical change control problem concerns a failure to re-evaluate relief requirements adequately when process fluids or operating conditions are changed, or when mechanical changes are made. Another example involves change from dry gas to wet gas operations. Key safety issues include different corrosion/erosion rates, liquid slugging effects, increased pigging frequency, hydrate formation/inhibition, and effects on blowdown, flare and vent systems.

Duty holders need to have systems to ensure that deliberate changes to the process and its equipment, or to the management system, are properly evaluated before their introduction. In addition, change can happen over time in a gradual way, and without a particular initiating event that can easily be recognised. It is important therefore that periodic reviews of process related hazards also occur, and attempt to identify changes that have occurred which may otherwise have been missed. These could relate to 'softer' issues such as manning, procedures, learning from previous incidents, or changes in industry or HSE codes, standards and guidance. Good practice in this area includes the use of system level hazard and operability studies, and "bow-tie" reviews.

This part reviews the way in which change is initiated, communicated, analysed, implemented, and reviewed. It involves a mix of onshore and offshore inspection; inspectors will need to decide on the best place to obtain the relevant information.

Change Control Procedure

A formal written procedure should ensure that all changes are assessed for impact on safe process operation. Some changes will require formal change control, but others will already have been evaluated for increased risk but will have been incorporated into the design basis and reflected in the normal operating procedures.

The procedure should identify: Scope of application; Roles and responsibilities; Risk analysis requirements; Communication (including notifications); Training; Implementation; Monitoring and review.

Change control procedure should apply to:-

- major plant additions or modifications
- changes in process operating parameter (control, alarm, or trip setting)
- changes in mode of operation
- Replacement of equipment with non-identical parts or addition of new equipment (whether for safety-related purposes or not)
- A change outwith the design intention
- Organisational changes
- Permanent as well as temporary changes

Temporary changes

An example of a temporary change is the use of an override or inhibit on a safety related system. Control of such changes is normally effected through a separate procedure for control of overrides / inhibits. However, use of overrides / inhibits needs to be kept under review, and any changes e.g. to modify or design out a trip function, should be handled through the change control procedure.

Organisational changes

Mapping of transfer of line management and functional responsibilities is necessary to prevent gaps e.g. contractor-based production operator fulfilling the new role of Control Room operator may require further emergency response training.

Matching of personnel and their skills to the requirements of the task is necessary for selection, and to identify outstanding training requirements.

Phasing of change may be necessary for safe transfer from the old to the new regime. Training needs should be scheduled, resourced and tracked over a period of time culminating in an assessment process to assure competence of production operators.

Roles and responsibilities

The opportunity for proposing changes should be widely available to people associated with process systems. Good practice includes provision for feedback on the reasons why each proposal has or has not been approved. Before changes are made, the workforce should be consulted.

Post-holders who can authorize different types of change should be clearly identified. The process should involve personnel with the background and experience to ensure that changes will not result in operations outside established safe limits.

There should be clear mechanisms for monitoring application of the procedure to ensure that it is not short-circuited or missed out altogether.

Auditing of the SMS, including change control, should be by independent competent persons (outside the line-management chain).

Hazard identification and Risk assessment

A variety of hazard identification tools are available, including HAZID, HAZOP, FMEA, Fault tree, Cause-Effect, What-If etc. Each has its own strengths and weaknesses, and suitability for assessing particular types of change, and procedures should specify a type appropriate to the nature of the change.

HAZID is a term that is often used to refer to safety studies of a brainstorming nature, sometimes driven by consideration of keywords selected appropriately to the scope of the study. It is particularly useful for considering changes to plant layout, and is sometimes used in conjunction with “walk-through” methods through existing plant, or computer-aided

virtual plant layout. The aim is to identify as many potential hazards as possible, for later assessment.

HAZOP is a systematic method of hazard identification for the assessment of process systems. If conducted against well-established guidelines the method brings the benefits of a multi-discipline team approach prompted by consideration of deviations from normal process operating parameters and their consequences. As the name implies the method is suitable for identifying hazards and also operability problems.

FMEA, failure modes and effects (criticality) analysis is a useful method for determining functional redundancy of protective system elements. It can be used to consider the effects of removal of layers of protection on process system integrity.

Fault tree analysis is a technique used to illustrate graphically the characteristics of protective and other systems, and may be used to quantitatively model failures of such systems.

Cause-consequence diagrams are used to graphically illustrate the range of outcomes that may arise from the success or failure of a system or its components.

Bow-tie diagrams are a method of illustrating the preventive and protective barriers that act to avoid of mitigate the consequences of a major accident scenario.

Risk assessment must be suitable and sufficient. Where hazards are identified, the risks may be assessed qualitatively or quantitatively. For most change control applications risk will be evaluated qualitatively using some sort of risk matrix. Where risks are computed numerically it is necessary to have a performance standard by which suitable comparisons of benefit vs. risk may be made. This may take the form of an implied cost of avoiding a fatality. If the risks are found to be intolerable and can not be reduced, then the change must not be implemented.

Risk assessments can sometimes become mechanistic and superficial. Line management should monitor the quality of risk assessment, and the implementation of prescribed control measures.

Actions from HAZID, HAZOP etc. should be summarized for tracking implementation in the as-built modification. The document control system should ensure that updated documents are available to personnel and that outdated documents are withdrawn from circulation

Safety Case / Verification

Even apparently minor changes to the safety case (SC) should be assessed and logged, and all relevant documentation updated. The SC should be revised periodically to incorporate relevant changes.

Material changes to the SC require submission to HSE 3 months prior to implementation. Material changes may include:

- modifications or repairs to the structure of any plant where the changes may have a major impact on safety
- new activities on the installation or in connection with it
- changes of operator or ownership or other circumstances involving changes in the management arrangements
- remedial measures resulting from an accident or incident investigation, or safety management system audit
- implementation of novel technology.

The duty holder is required to repeat PFEER risk assessments as appropriate.

The duty holder is required to operate a suitable written scheme of examination (PFEER Reg. 19) and verification scheme (SCR Reg. 21)

Operational Risk Management and Assessment

Operational Risk Management (ORM) is concerned with the determination and management of the measures necessary for continued operations where failure of a process, plant, equipment or procedure has the potential to adversely affect the risk profile of the installation at any level of operation. Operational risk assessment (ORA) is an integral part of ORM.

ORA's are considered to be a deviation from an installation's design intent and as such provide an indication of where the design and/or design intent may be flawed, plant is not adequately maintained or is used outside of its normal operating envelope or design parameters. It is essential that ORA's are produced, verified, controlled, applied, monitored, audited and liquidated to the highest standards.

See separate HID Inspection Guide Offshore on Operational Risk Assessments which has been developed for this.

Supporting Standards/ACoP or Guidance

- HSWA s2(1) provision and maintenance of plant and safe systems of work that are, …. safe and without risks to health, and s3(1) ensure, … that persons not in his employment ....are not ... exposed to risks to their health and safety.
- MHSWR Reg. 3, suitable and sufficient assessment of the risk ... and that any such assessment shall be reviewed … if there is a reason to suspect that it is no longer valid or there has been a significant change in the matter to which it relates.
- SCR Reg. 14 require the revision of the contents of the SC as often as may be appropriate and/or where revision will render the SC materially different.
- SCR Regs. 20 & 21 review, revision, and continuing effect of verification scheme
- PFEER Reg. 5(1) assessment to be performed and repeated as often as may be appropriate
- PFEER Reg. 19(2) & (3) operation of a suitable written scheme of examination
- Oil & Gas UK Publication - HS071- Guidance on the Conduct and Management of Operational Risk Assessment for UKCS Offshore Oil and Gas Operations
- Step Change Publication "Managing Risks to prevent and minimise the impact of Major Accidents"

Appendix 9 Miscellaneous Process Hazards

This part reviews the way in which some miscellaneous process hazards are managed. Not all the hazards will be relevant to every installation. Topics covered include:-

1. Control of H2S and CO2
2. Sand management
3. Control of hydrates
4. Sampling arrangements
5. Protection against air ingress and flammable mixtures in process plant
6. Segregation of hazardous drains
7. Leak management
8. Plant re-instatement following maintenance or an idle phase

Control of H_2S and CO_2

Gas streams associated with some reservoirs have to be treated to reduce the Carbon Dioxide (CO_2) or Hydrogen Sulphide (H_2S) to levels to meet export pipeline gas specifications. Two main methods are used, these are a) counter-current contact in which the gas stream rises through a column against a downward flowing stream of amine or proprietary solvent, and b) absorption, where the gas stream may be passed through a column packed with zinc oxide in powder or granular form .

Risks arising from presence of H_2S and / or CO_2 should be assessed, and appropriate controls put in place, based on recognised codes and standards. Controls should include actions to keep process plant within safe operating limits, through start up, normal operation and shutdown phases. Procedures should describe the potential consequences of failing to control the process in this way, and contingencies for upsets / emergencies.

H_2S & CO_2 form corrosive acidic solutions in the presence of water. In view of the hazardous and toxic nature of these gases maintaining the integrity of the plant is essential. An effective system should be in place to monitor the condition of pipework and equipment. Repairs and replacement of plant must be to a suitable standard (e.g. the NACE standard for equipment containing H_2S)

Supporting Standards/ACoP or Guidance

- API RP 55 - ‘Conducting Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulphide’ covers recommendations for protection of employees as well as conducting oil and gas processing plant operations where hydrogen sulphide is present in the fluids.

- ANSI B 31.3 covers extra requirements for the system design, fabrication and inspection for systems containing 'M' fluids, which H_2S containing streams may fall into.

Sand Management

Production of sand with well fluids presents several potential hazards for topsides pipework and equipment, for example:

- Sand plugging causes valves to seize, potentially compromising ESD action.
- Accumulated sand requires operator intervention to remove it, by sand-washing, digging out, or dismantling of plate exchangers.
- Sand accumulation can prevent corrosion inhibitor reaching the material surface leading to increased corrosion.
- Sand accumulation in level instruments and bridles can lead to false readings and poor control, and may compromise shutdown initiation.

Risks arising from presence of sand should have been assessed, and appropriate controls put in place. Sand management strategies may aim to prevent sand production, or may rely on monitoring to avoid loss of containment. The following elements should be included in any strategy:

- A policy or strategy statement as to how sand hazards are managed
- Arrangements for assessment of sand-related hazards
- A reservoir management strategy for sand control
- Sharing of experience of sand problems with others.

Effective systems should be in place, onshore and offshore, for the management of sand production,

- If the sand management strategy allows some sand production, limits on sand production should be set
- Lesson learned from flowline inspection programmes should be captured
- Operating conditions, particularly fluid velocity, should be optimised to minimise erosion
- Wall thickness checks, of critical areas of pipework, should be undertaken
- The verification body should verify the effectiveness of the sand management strategy.

If sand monitoring systems are provided:

- The philosophy for sand monitoring should be clear, i.e. is it alarms only, periodic measurement, or continuous monitoring?
- Sand monitoring instruments should be calibrated.
- ‘Trending’ the results should facilitate deterioration over time to be measured
- If results from one instrument are used to infer conditions in other places, (e.g. monitoring on one flowline used to infer conditions in other flowlines), the validity of the assumptions used should be robust
- Appropriate actions should be taken if alarm limits are exceeded.

Operators should be aware of the hazards associated with sand production and the limits of individual wells and operating plant. Operating procedures may include:

- Restrictions on the operation of individual wells or systems

- Control of the operation of chokes to avoid settings where erosion may occur
- Procedures for removal of sand from vessels, etc.

Supporting Standards/ACoP or Guidance

- DCR Reg. 14. requires the well operator to assess the well conditions and any hazards
- PFEER Reg. 9 requires duty holders to take appropriate measures for preventing the uncontrolled release of flammable etc substances
- PUWER Reg. 5 requires the maintenance of work equipment in an efficient state

Control of hydrates

Hydrates are ice-like solids that can form when wet gas and light condensate at high pressures cools to lower temperatures. Hydrates are formed by gas cooling to below its water dew point, or when free water is present. Cooling may be due to operational pressure drop, or during start-up when hydrocarbon is introduced into cold pipework or equipment. Once formed hydrates are difficult to remove; prevention is better than cure. Hydrate inhibitor, such as glycol, methanol or industrial methylated spirits, is used to inhibit the formation of hydrates, by removal of free water. Hazards caused by hydrates include:

- Blockage of pipework, and instrument tappings, causing false readings.
- Plugging of valves, giving operational problems, and potentially compromising ESD action.
- Hydrate particles travelling at high gas velocities can cause large forces at elbows and tees.

Removal of hydrates may require physical intervention, with associated risks. Sand particles can erode piping and fittings, particularly chokes and flowlines,

If hydrates form there may be large slug forces at bends and tees in piping systems. There are also hazards associated with methanol injection into wells and flowlines, where pressures may be >100 bar.

The potential for hydrate formation under non-routine activities should be addressed in operating procedures. These should include:-

- Actions to keep within safe limits by preventing hydrate formation, and the consequences of failing to do so
- Procedures for start up, normal operation and shutdown
- Contingency procedures e.g. for situations where hydrate formation is suspected, or where the supply of inhibitor is interrupted.

It is essential that the hydrate inhibitor is present at the point where gas / condensate is cooled to its hydrate formation temperature. Therefore injection should be upstream of control valves, choke valves or any place where pressure reduction takes place. The flowrate of inhibitor required should be determined based upon the hydrocarbon flowrate.

Supporting Standards/ACoP or Guidance

Canadian Association of Petroleum Producers Publication "GUIDE - Prevention and Safe Handling of Hydrates" 2013 review

Sampling arrangements

Sampling involves directly breaking into the hydrocarbon containment envelope. Hazards associated with potential loss of containment, and static electricity, should be recognised.

The hazards associated with breaking into the hydrocarbon containment envelope should be specifically addressed in procedures for interventions into the process plant. Operating procedures should include:

- Techniques for sampling all the likely fluids
- All the types of sample connection in use
- Precautions to be taken during sampling
- Contingency procedures for upsets / emergencies.

Only properly designed and designated sample points should be used for taking samples. Serious incidents, involving loss of containment, have occurred where unofficial connections have been used for sampling.

Closed bomb sample loops may be used in preference to open sample vessels. Specifications should be available for pressure ratings, etc. for sample bombs. There should be a system in place to assure the integrity of the pressure containing sampling equipment.

For open sample connections the design of the system should prevent the accumulation of any static electrical charge, for example, by the avoidance of non-conducting surfaces and the bonding of metal parts. Efficient static bonding connectors should be provided.

NFPA Recommended Practices Manual Vol 9 Section 77 recommends that containers of more than 5 gal (19 litre) capacity made of non-conducting materials should not be used without special precautions. BS 5958 Part 2, paragraph 12.4.4 notes that when a liquid of low conductivity is being handled, and various other specified precautions are applied, a small electrostatic charge may remain, but it is common practice to use high resistivity containers with capacities up to 5 litres.

Other precautions referred to in BS 5958 Part 2 include earthing of conducting components and adjacent objects, limitations on filling rate, avoiding rubbing the external surface of the container, and ensuring that personnel in the vicinity of the container do not present an ignition risk.

Supporting Standards/ACoP or Guidance

See text above

Protection against air ingress and flammable mixtures in process plant

Flammable mixtures can form in piping, plant and equipment when air enters systems that normally contain hydrocarbon, as a result of operational or maintenance activities. Correct purging and operational procedures will ensure that the risks are minimised.

Inert gas purging with nitrogen is often used to remove hydrocarbons from process equipment, without taking it through a flammable mixture regime. It is important however to ensure that the reverse flow of hazardous fluids into the inert gas purging system cannot occur, as there is a risk of a flammable or toxic atmosphere being inadvertently generated elsewhere. Controls typically include:-

- ensuring that the supply gas always has a higher pressure than the system being purged
- interlocks between purge gas supply isolations and system inlet isolations
- use of non-return valves in the purge gas supply
- local procedures/links with isolation certificates

Inert atmospheres generated by purging processes need to be safely vented, and in particular prior to disconnection of any temporary purging connections, due to the risk of local low concentrations of oxygen being generated.

Purging of flare and vent headers is required to prevent air ingress, which could lead to a flammable mixture forming in the system. Purge rates may vary depending on the operating mode. If there are sufficient continuous and incidental discharges from the process into the flare system a minimum purge rate may be acceptable. Purge points should be located at the upstream end of headers to ensure that there are no dead ends. Alternative supplies of purge gas (e.g. nitrogen, fuel gas or propane) should be available, and used when the normal supply is not available.

Fuel gas or nitrogen may also be provided to some tanks and vessels (such as methanol or glycol storage tanks, cooling/heating medium expansion vessels or open/closed drains tanks) to maintain system pressurisation, allow for expansion/contraction or to exclude air to prevent formation of an explosive atmosphere or to prevent chemical degradation.

Procedures for maintenance intervention, and for restoring equipment back into service, should address the control of any flammable atmosphere that may be formed. Purging with nitrogen or other inert gas, prior to intervention or restoring equipment back into service, will minimise the flammable atmosphere. Following maintenance, sampling of the ‘inert’ atmosphere should be undertaken to ensure that the oxygen content is less than a specified amount (typically $<5\%$ O_2). For interventions that are carried out routinely, e.g. pig traps, dedicated arrangements for purging and venting should be provided. If tanks or caissons are opened for maintenance from which hydrocarbon cannot be fully removed special precautions may be necessary (e.g. continuous purging or foam blanketing). If nitrogen is produced on the installation using a nitrogen generation plant, the quality of the nitrogen should be assured, and high levels of oxygen in the ‘inert’ product gas prevented.

Supporting Standards/ACoP or Guidance

PFEER Reg. 9 measures to prevent fire and explosion and the accumulation of flammable or explosive atmospheres

Segregation of hazardous drains

Open drain systems are typically classified as hazardous and non-hazardous. It is important that segregation of the drain systems is maintained at all times to prevent migration of hydrocarbons into safe areas where they may present an ignition risk.

Seal pots and seal loops in the drain headers are used to provide segregation between drain systems. Seal pots and loop seals can either rely on a continuous or a dedicated water supply, which should maintain **all** seals liquid full. Routine plant inspections should include checking that seals are intact and that no debris has collected to block drains or gullies.

Vents or siphon breakers should be provided at vertical falls to prevent liquid being siphoned out of the seal.

Segregation of the drains systems is also necessary at the drains caisson. Dip pipes for the non-hazardous drains should be lower than those for the hazardous drains, to prevent migration of gas. The integrity of the dip pipes should be assured. (The dip pipes may have corroded off or perforated at or above the water line).

Lute seals (U bends) may also be provided on drains tanks, bulk storage tanks, tanks in columns and crane pedestals. These provide a liquid seal to prevent migration of gas between systems. The integrity of these seals should be maintained.
Winterisation of drain lines (particularly across bridges) and seal loops may be provided to prevent blockage. Winterisation should be maintained in good condition, and its effectiveness assured.

The implications on the drain systems of any changes to the area classification of the installation should have been addressed, e.g. an area with new equipment redesignated as Zone 1 or 2 yet still drained by a non-hazardous drain.

Supporting Standards/ACoP or Guidance

- PUWER Reg. 5 ensure equipment is maintained in an efficient state, in efficient working order and in good repair
- PFEER Reg. 9 measures to prevent fire and explosion and the accumulation of flammable or explosive atmospheres

Leak management

All process plant has the potential for losses of containment to occur. A strategy should therefore be in place to manage these.

Where any leaks are small, the associated hazards are deemed to be low (or manageable), and there are operational constraints or other more significant hazards that

may be introduced by an immediate response to take the leaking system out of service, DHs may decide to continue to operate for a period with a leak. It is essential however that the risks of doing so are identified, measured and controlled. In many ways this can be viewed as an ORA, but there are some specific considerations.

An essential first step is to ensure that all leaks are identified and subsequently assessed. Leaks need to be reported and managed, even if they appear in themselves to be of low hazard (e.g. a water system), as inevitably they only ever get worse, and can have higher hazard consequences for surrounding plant, people and equipment.

Key to performing an appropriate hazard analysis is to determine an accurate picture of the condition of the equipment, and the cause of the leak. This needs to be informed by an understanding of the mechanical nature of the equipment, its likely failure mechanisms, and suitable measurement of the deterioration that has allowed the leak to occur. In the case of a leak from a hole in a pipe for example, such measurement could consist of a map of pipe wall thickness measurements surrounding the leak site.

Further to this, it is necessary to understand how the deterioration might progress with time, based on an understanding of the failure mechanism. The more rapid the deterioration, the greater the potential hazard, as the opportunities to detect and intervene before an unacceptable situation develops are reduced. The rate of deterioration may not be fixed. For example a minor, gradually increasing leak from a valve packed gland may suddenly escalate when a fastener on the gland packing hold down plate corrodes through.

Finally the hazard consequences of the leak, under all deterioration modes needs to be identified and assessed. At the end of the assessment process, it may be decided that the risk of operation with the leak is intolerable, and it should be taken out of service. It is essential that the status of such equipment is effectively recorded/communicated and put 'beyond use' such that it cannot inadvertently be put into service.

Where it is determined that the leak may be managed, appropriate control measures should be put in place that reduce the risk to ALARP. Control measures need to be focussed on ensuring that the current status of the leak is known, any deterioration is re-assessed, and appropriate responses to specified levels of deterioration are identified upfront, such that action can be taken before unacceptable levels of hazard occur. Measures need to be realistic to implement, and responsive enough to the dynamic nature of the level of risk as the leak deteriorates. Suitable additional control measures may include warning signs, barriers, safe secondary containment systems, gas detection systems and regular monitoring regimes, amongst others, and these need to be appropriately documented, communicated, and compliance with them monitored. Ultimately, operational staff need to feel empowered to be able to respond and take equipment out of service if necessary, without recourse to significant higher management.

Supporting Standards/ACoP or Guidance

- PFEER Reg. 9 requires duty holders to take appropriate measures for preventing the uncontrolled release of flammable etc substances.
- PUWER Reg. 5 requires the maintenance of work equipment in an efficient state.

Plant re-instatement following maintenance or an idle phase

Introduction of fluids into a process system that has recently undergone maintenance activity, or has been in an idle phase, has a number of associated hazards, and can be addressed as a particular form of management of change. Ineffective control of this process was clearly fundamental to the Piper Alpha disaster. In order to control the activity, effective application of PTW and isolation certificates is essential. There may however be other, wider considerations not traditionally captured under such safe systems of work.

There should be a policy describing how plant should be brought back into service post maintenance. Key elements within in such a policy should include such steps as:-

- A visual check. This should confirm that;-
  - the maintenance tasks appear to have been completed as expected
  - equipment is in place as per design
  - all isolations have been removed
  - all vents/drains are in their correct positions
  - all actions identified by any management of change processes associated with the prior outage that require completion pre-start-up have been done etc
- Leak test with lower hazard fluid to ensure that the risk of a leak on reintroduction of fluids is minimised. This should specify
  - which systems need to be tested
  - which test fluids to use
  - which pressure to test at, and a performance standard that needs to be achieved.
  - Where the standard is not initially achieved, a description of how it should be rectified, and what re-testing is necessary. A range of approaches from ‘flog-up’ to re-joint, to flange inspection to pipe-work realignment and repair may be appropriate.
- Removal of leak test fluids in a safe manner and consideration of whether residues of these will introduce any additional hazards (e.g. moisture in a dry/acidic system)
- Assessment of the pressure, temperature, flow and composition of the fluids to be introduced and the implications of these on the capacity of the process and storage systems affected. This may be particularly relevant when re-starting a well that has been shut-in for a period of time

The risks of start-up should be considered more widely than just the demands on the equipment. Start-up risk assessment may consider other factors as to whether other plant systems and resources are ready to support the reinstatement of the equipment. This can include the need for:-

- Notification of relevant parties (e.g. other individuals or installations)
- Confirming that the team have sufficient knowledge/understanding of the task, and that start-up will not cross-over a shift/crew change period, or if it does the risks are sufficiently low

- Checks that emergency systems that may operate should a start-up be aborted are ready, trip inhibits have been removed, there are no other management of change assessments in place which could interfere with the start-up etc)

Steps should be recorded, with authorised stage-gates to confirm completion by a supervisory level, prior to moving on to the next phase.

Supporting Standards/ACoP or Guidance

- MHSWR Reg. 3, requirement for suitable and sufficient risk assessment
- MHSWR Reg. 5 requires arrangements for planning and control ... of preventive and protective measures.
- PUWER Reg. 8 requires adequate health and safety information and, where appropriate, written instructions.
- PFEER Reg. 9 requires appropriate measures for preventing the uncontrolled release of flammable etc substances.
- Oil & Gas UK Publication - OP069 – “Well Integrity Guidelines”, Issue 1, July 2012

Appendix 10: Monitoring & Review Arrangements

The dutyholder should have systems in place to monitor the implementation of the controls or mitigations put in place for each of the intervention areas. There should also be effective monitoring of the application of the process. Appropriate leading and lagging process safety performance indicators should be in place for all key elements.

Inspectors should review available evidence, such as records, to determine what monitoring is being carried out. The inspection should also identify whether the monitoring systems are identifying any problems with the implementation of the system and controls and, if this is the case, what has been done to rectify matters.

In addition to monitoring there should be arrangements for periodic audit. Any available audits should be reviewed to determine whether they meet the necessary objectives of assessing compliance with the procedure and providing assurance that the system is effective in controlling the risks associated with each area.

A number of process safety performance indicators that may be useful in monitoring the health of the systems and barriers associated with prevention of loss of containment are presented below. Some are instantaneous ‘snap-shot’ values, whereas some should be used to record the number of occurrences of a particular set of circumstances over an appropriate time period (e.g. shift, day, week, month, quarter). Appropriate target or threshold levels should be set for action. Discussion of the reasons for the live values as well as the values themselves is important. These are provided as guidance only, and it is important that Duty Holders determine and utilise a set of indicators that is relevant to their own assets and safety management systems.

1. Process Plant construction and commissioning processes

- % of incomplete HAZOP actions
- % of required operating instructions which have been issued
- % of identified operating technician training in new equipment which is complete
- % of identified critical joints which have been passed as fit for service
- % of identified critical joints which have failed initial inspection
- No. of design changes identified for assessment during each phase (construction, commissioning, early operation)
- No. of leaks identified during leak testing (by system)
- No. of punch list items by priority

2. Process Plant operation within safe limits

- No. of occasions safety critical operating parameters are exceeded
- No. of demands on safety critical alarms
- No. of demands on SIL 1 or above instrumented protective systems
- No. of demands on mechanical relief devices
- No. of process operating procedures which are beyond their due date for review
- No. of live investigations of process upsets/excursions
- No. of live (incomplete) actions arising from process upsets/excursions
- No of control valves which are physically bypassed
- No of control loops which are operated in manual mode

- No. of hours that safety critical equipment is out of service
- No. of hours that safety critical equipment is impaired

3. Instrumented Protection Systems

- No. of current inhibits of instrumented protective systems
- Cumulative time that instrumented protective systems have been inhibited
- Alarm frequency rate in control room (alarm/operator/hour)
- No. of standing alarms (alarmed/accepted but not reset)
- No of failures of SIL 1 or above protective systems to meet required performance standard on periodic test

4. Relief, Blowdown and Flare systems

- % of time that flare knockout drum level is less than design level required to provide adequate separation capacity
- % of time that oxygen level in flare/vent system is >10%
- No. of occasions of activation of blowdown
- No. of systems where blowdown performance standard is not met (either on test or 'in anger')

5. Process Isolation Standards

- Isolation standards monitoring audit scores
- No. of 'live' baseline standard non-compliant isolation schemes
- No. of locked open/locked closed valves out of normal position
- No. of 'long term' isolations

6. Permits to Work

- PTW monitoring audit scores
- No. of PTW issued (or live) per day (average or peak over a set period)

7. Management of small bore tubing, piping and flexible hoses

- % completion of routine small bore tubing visual assembly checks
- % of hoses in date periodic inspection

8. Management of change

- No. of live (incomplete) management of change projects
- No. of live (incomplete) management of change projects older than x months
- No. of live temporary management of change projects
- No. of live ORAs
- No. of live instrument overrides/inhibits
- No of outstanding HAZOP or process hazard review arising actions

9. Other Offshore Process Hazards

- Average H_2S/CO_2 level in well streams

- Sand monitoring results
- Flare header purge flow rates
- No. of live leaks/seeps being monitored
- No. of live leaks/seeps operating beyond originally targetted repair date

Supporting Standards/ACoP or Guidance

- HSE Publication HSG 254 'Developing process safety indicators'
- OGP publication no. 456 "Process Safety – Recommended Practice on Key Performance Indicators" as good practice guidance

Appendix 11: Duty Holder Performance Assessment

When inspecting Loss of Containment related systems there are two areas of to be considered as follows;

1. When inspecting the outputs from the systems, a decision will have to be reached on whether the risk control measures implemented led to compliance with the relevant legislation. This decision will be made in the same way as for other inspection topics by comparing the standard of control achieved against the relevant benchmarks and applying the principles of EMM.

2. The inspection will reach conclusions on overall effectiveness of the dutyholder's systems. These should be recorded using the assessment criteria listed below. Those dutyholders who either do not have systems, or have system that are substantially ineffective will fall in the very poor or unacceptable categories. Where systems are in place and there is evidence of a number of examples where it results in controls that are ineffective or inappropriate it will fall in the poor category.

EMM RISK GAP					
EXTREME	**SUBSTANTIAL**	**MODERATE**	**NOMINAL**	**NONE**	**NONE**
TOPIC PERFORMANCE SCORE					
60	**50**	**40**	**30**	**20**	**10**
Unacceptable	**Very Poor**	**Poor**	**Broadly Compliant**	**Fully Compliant**	**Exemplary**
Unacceptably far below relevant minimum legal requirements. Most success criteria are not met. Degree of non-compliance extreme and widespread. Failure to recognise issues, their significance, and to demonstrate adequate commitment to take remedial action.	Substantially below the relevant minimum legal requirements. Many success criteria are not fully met. Degree of non-compliance substantial. Failures not recognised, with limited commitment to take remedial action.	Significantly below the relevant minimum legal requirements. Several success criteria are not fully met. Degree of non-compliance significant. Limited recognition of the essential relevant components of effective health and safety management, but demonstrate commitment to take remedial action	Meets most of the relevant minimum legal requirements. Most success criteria are fully met. Degree of non-compliance minor and easily remedied. Management recognise essential relevant components of effective health and safety management, and commitment to improve standards.	Meets the relevant minimum legal requirements. All success criteria are fully met. Management competent and able to demonstrate adequate identification of the principal risks, implementation of the necessary control measures, confirmation that these are used effectively; and subject to review.	Exceeds the relevant minimal legal requirements. All success criteria are fully met. Management competent, enthusiastic, and proactive in devising and implementing effective safety management system to 'good practice' or above standard. Actively seek to further improve standards.
EMM INITIAL ENFORCEMENT EXPECTATION					
Prosecution / Enforcement Notice.	Enforcement Notice / Letter.	Enforcement Notice / Letter.	Letter / Verbal warning.	None.	None.