ASSURANCE & VERIFICATION PRACTITIONER’S GUIDE

Managing Risks to prevent and minimise the impact of Major Accidents
OUR VISION

Making the UK the safest place to work in the worldwide oil and gas industry
Offshore Oil and Gas is a unique industry where Operators and a wide range of supporting personnel, from catering staff to technical specialists, work and live for extensive periods of time in relatively close proximity to large inventories of flammable, explosive and sometimes toxic substances. They face significant challenges in the event of an emergency when there is an urgent need to distance themselves quickly from the hazard, because of a compact and complex site, and the need to evacuate or escape by air or sea should it become necessary. It is therefore apparent that offshore installations demand a high level of attention to risk management.

Following the fire and explosion on the Piper Alpha platform in July 1988, when 167 lives and the entire installation were lost, the enquiry into the disaster raised 102 recommendations. These were endorsed by the government and led to a suite of new goal setting safety Legislation which forms the framework used today to address and manage the risks of Major Accident Hazards (MAH) on Offshore Oil and Gas installations within UK waters. These Regulations specifically introduced the concept of Safety Critical Elements (SCEs).

In recognition of the unique risks faced by the industry, additional requirements for the examination of safety plant and equipment, by Independent and Competent Persons (ICPs), which does not exist in any of the other high hazard industries, was placed in Law. This process is called Verification. At the same time, requirements were set for Duty Holders to review their processes, involving routine maintenance and inspection and testing to minimise MAH risk. These are referred to as Assurance activities and are often encompassed within the overall Verification Scheme, which can lead to some confusion over roles and responsibilities of the Duty Holder and the ICP.

Following a major review by the UK Health and Safety Executive, between 2004 and 2007, of the condition of safety equipment and the supporting management processes, it was expressed that Verification was not delivering the benefits expected by Stakeholders. This challenge was taken up by the industry through Step Change in Safety and a 2 year programme of work (2010 - 2012) was undertaken to improve the understanding and awareness of the benefits of good assurance of integrity by Duty Holders, and Verification by ICPs; involving contribution from Operators, ICPs, the HSE and contractors.

This suite of guidance is made available to the industry through Step Change in Safety and is designed to support those who wish to improve their understanding of the processes for Assuring and Verifying the integrity of our offshore installations.

As the UK Offshore Oil and Gas industry progresses into a sixth decade of operation, we have become a “mature basin” with an ageing infrastructure and many installations operating beyond their original design life, in some cases, with new or changing Operators. In consequence, we have an increasing need to continually improve processes and engagement by all parties, to raise the understanding of the changing condition and capability of plant, and to allow the right actions to be taken to assure the integrity of our installations.
This document could not have been produced without substantial valuable contributions from many people with knowledge of Assurance and Verification. However, these subjects have been discussed for many years since MAH Management Legislation was issued and significant best practice has since evolved. There is substantial passion amongst the community of Engineers to “do it right”, however, it is clear that the interpretation of what is “right” is very difficult to agree. The text that has been developed in this document is the result of intense activity by many people and it is unlikely that any one of them will fully agree with the entire content. What follows is not a definitive guide, but represents the opinions of people who have worked with the UK offshore Legislation and managed SCEs for many years, and provides perspective and guidance to those seeking help.

Contributors to the development of this document include the following:

AMEC
Apache North Sea Limited
BG Group
BP North Sea
Britannia Operator Limited
Bureau Veritas
Centrica Energy
Chevron Upstream Europe
ConocoPhillips (UK) Limited
Diamond Offshore Drilling
DNV
Ensco
ExxonMobil
GDF SUEZ E&P UK Ltd
GL Noble Denton
The Health and Safety Executive
IMES
Lloyds Register EMEA
Maersk FPSOs
Maersk Oil
Nexen Petroleum UK
Oil and Gas UK
Perenco UK - SNS
Petrofac
Plant Integrity Management
Shell U.K. Limited
Step Change in Safety
Talisman Energy (UK) Ltd.
TAQA Bratani
Total E&P UK Ltd
Transocean
Wood Group
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<td>ACOP</td>
<td>Approved Code of Practice</td>
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<tr>
<td>ALARP</td>
<td>As Low As Reasonably Practicable</td>
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<tr>
<td>COMOPS</td>
<td>Combined Operations</td>
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<tr>
<td>DCR</td>
<td>The Offshore Installations and Wells (Design and Construction, etc) Regulations</td>
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<td>DECC</td>
<td>Department of Energy and Climate Change</td>
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<td>DH</td>
<td>Duty Holder</td>
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<td>EC</td>
<td>Engineering Contractor</td>
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<td>ESD</td>
<td>Emergency Shutdown</td>
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<td>ESDV</td>
<td>Emergency Shutdown Valve</td>
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<td>F&amp;G</td>
<td>Fire and Gas</td>
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<tr>
<td>FARS</td>
<td>Functionality, Availability, Reliability and Survivability (Performance Standard model)</td>
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<tr>
<td>FPSO</td>
<td>Floating Production, Storage and Offloading (vessel)</td>
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<td>FPU</td>
<td>Floating Production Unit</td>
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<td>FRA</td>
<td>Fire Risk Analysis</td>
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<td>GA</td>
<td>General Alarm</td>
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<td>HAE</td>
<td>Hazardous Area Equipment</td>
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<td>HAZID</td>
<td>Hazard Identification Study</td>
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<td>HAZOP</td>
<td>Hazard and Operability Analysis</td>
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<td>HID</td>
<td>Hazardous Installations Directorate</td>
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<td>HSE (without “The”)</td>
<td>Health, Safety and Environment</td>
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<td>HVAC</td>
<td>Heating, Ventilation and Air Conditioning</td>
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<tr>
<td>ICP</td>
<td>Independent and Competent Person (this is often interchanged with “Verifier” and also IVB meaning Independent Verification Body and should be considered to mean the same)</td>
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<tr>
<td>ICSS</td>
<td>Integrated Control Safety System</td>
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<td>IVB</td>
<td>Independent Verification Body (see also ICP)</td>
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<td>KPI</td>
<td>Key Performance Indicator</td>
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<td>MA</td>
<td>Major Accident</td>
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<td>MAH</td>
<td>Major Accident Hazard</td>
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<td>MAR</td>
<td>The Offshore Installations and Pipelines Works (Management and Administration) Regulations</td>
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<td>MIST</td>
<td>Minimum Industry Safety Training</td>
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<td>MOC</td>
<td>Management Of Change</td>
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<td>MOU</td>
<td>Mobile Offshore Unit</td>
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<tr>
<td>MMS</td>
<td>Maintenance Management System</td>
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<td>MTBF</td>
<td>Mean Time Between Failure</td>
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<td>NDT</td>
<td>Non-destructive Testing</td>
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<td>OEM</td>
<td>Original Equipment Manufacturer</td>
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<tr>
<td>OPPS</td>
<td>Overpressure Protection System</td>
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<tr>
<td>PA</td>
<td>Public Address</td>
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<td>PFD</td>
<td>Probability of Failure on Demand</td>
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<tr>
<td>PFEER</td>
<td>The Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations</td>
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<tr>
<td>PMR</td>
<td>Planned Maintenance Routine</td>
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</table>
**Terms, Abbreviations and References**

- **POB**: Personnel On Board
- **PS**: Performance Standard
- **PSR**: Pipeline Safety Regulations
- **PT**: Pressure Transmitter
- **PTW**: Permit to Work
- **PUWER**: Provision and Use of Work Equipment Regulations
- **QA**: Quality Assurance
- **QRA**: Quantitative Risk Analysis
- **RAR**: Remedial Action Recommended
- **RBI**: Risk Based Inspection
- **RCA**: Root Cause Analysis
- **SCEs**: Safety Critical Elements, including Specified Plant as appropriate
- **SCR / OSCR**: The Offshore Installations (Safety Case) Regulations
- **SIL**: Safety Integrity Level
- **SOLAS**: Safety of Life at Sea
- **Specified Plant**: Specific safety related plant and equipment as defined in PFEER, Regulation 2
- **The HSE**: The Health and Safety Executive
- **TA**: Technical Authority
- **TE**: Temporary Equipment
- **TR**: Temporary Refuge
- **UPS**: Uninterruptible Power Supply
- **WSE**: Written Scheme of Examination

**References**

- The Public Inquiry into the Piper Alpha Disaster - Lord W Douglas Cullen
- Plant Ageing: Management of equipment containing hazardous fluids or pressure - Research Report RR509 HSE Books 2006
- Step Change - The Asset Integrity Toolkit
- Energy Institute Guidelines for the management of safety critical elements (2nd Edition)
- Energy Institute Research report: A framework for monitoring the management of ageing effects on safety critical elements
- A guide to the Offshore Installations (Safety Case) Regulations 2005
- Successful health and safety management (HSG 65) HSE 1997
- Provision and Use of Work Equipment Regulations 1998 (PUWER)
- Directive 94/9/EC The ATEX Equipment Directive (also known as ATEX 95)
- Directive 99/92/EC The ATEX Workplace Directive (also known as ATEX 137)
- HSE Offshore Information Sheets 4/2009 (Guidance on management of ageing and thorough reviews of ageing installations) and 5/2007 (Ageing semi-submersible installations)
- HSE Nature and Frequency of Verification of Safety Critical Elements HID Semi Permanent Circular SPC/Enforcement/43
- A guide to the well aspects of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996
- A guide to the installation Verification and miscellaneous aspects of amendments by the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 to the Offshore Installations (Safety Case) Regulations 1992
The current suite of applicable Offshore Safety Regulations and the associated risk management processes were developed following the enquiry into the Piper Alpha disaster, for the identification and management of the hazards which could lead to Major Accidents. This is internationally recognised as a best practice and is widely utilised by other countries in the development of their own Regulatory regimes. However, in the period since 1992 when these Regulations started to be issued and take effect, there has been a wide variance in understanding of the content and interpretation of the expectations for implementation. The current safety regime was intended to put in place mandatory requirements which, if followed correctly, would reduce the likelihood that such a Major Accident could happen again.

Figure 1 - UK Legislation
2. INTRODUCTION, SCOPE AND OBJECTIVES

The management of Major Accident Hazards (MAHs) represents critical activities to support the low probability high consequence events which require a different approach to the occupational, or personal, safety management processes and programmes which are associated with higher frequency but lower consequence events. The basic reason for this is that while single failures can cause dangerous occurrences, Major Accidents do not generally happen as a result of a failure of one piece of equipment or one wrong action by an individual. Instead, they are epitomised by a series of failures of plant, personnel functions and processes and procedures. Following a major accident, it is not unusual for personnel within a company to reflect that all the signs of the likelihood of the eventual accident were evident but the operating company and personnel had not been able to recognise this and make the necessary changes to plant, people and processes, which become obvious and natural to do, after such an accident.

While substantial improvements in safety have been achieved as a result of the application of the OSCR, the level of understanding and interpretation has been shown to vary significantly amongst those holding responsibilities. In particular, the requirement for ICP Verification of key plant performing safety critical functions needs to be clearly understood and consistently applied.

Following a major review of the condition of safety equipment and supporting management processes undertaken by the UK Health and Safety Executive between 2004 and 2007, it was expressed that Verification was not delivering the benefits expected by Stakeholders.

In consequence, an initiative was developed by the “Step Change in Safety Asset Integrity Steering Group” to create a subgroup with a scope of investigating the challenges faced and developing guidance for use by the industry for the purpose of:

• Raising understanding of the framework for MAH Management
• Improving understanding of the Roles and Responsibilities of the Duty Holder in assuring the performance of SCEs
• Clarifying the role and function of the ICP
• Providing a reference document for use by Duty Holders and ICPs

The Assurance and Verification Subgroup was formed in 2010 with a wide industry involvement of Operators, Drilling companies, key service suppliers, ICPs and the HSE, who all had passionate opinions on the processes of Assurance and Verification. A two-year programme was set to investigate the challenges faced, share understanding through regular meetings and develop guidance and education material with the objective of improving understanding of the best practices being used in the industry.
At the outset, the Subgroup sought to identify the main areas of focus to be addressed and these are reflected in this suite of documents. The following areas were identified for specific attention:

- Improving understanding of MAH barriers related to SCEs
- Clarifying the Assurance and Verification processes to all industry personnel
- Improving:
  - understanding of MAHs
  - the content and quality of Performance Standards
  - control of Temporary Equipment
  - understanding of the importance and the basic process for Management of Change with respect to the management of SCEs
- Providing guidance on training and competency needs for ICPs and Duty Holder personnel
- To discuss relationship & communication matters between Duty Holders, ICPs and other stakeholders which impacts on the effectiveness of Verification.

In general, the aim of the identified focus areas was to raise awareness of how everyone can contribute to MAH safety management through better understanding of SCEs and their functions.

To meet the needs of different Stakeholders it was decided to produce three documents.

The first is in the form of a high level overview to provide a short and simple summary to communicate the basic messages of Assurance, Verification and Major Hazard Management so that any reader can quickly gain an awareness of the framework and recognise the importance of their involvement and how they can participate in reducing risk.

A second document provides more detail on the framework by explaining the intent behind the Regulatory requirements and may be used by those who need to raise their understanding of the expectations of Assurance and Verification functions to comply with the OSCR and the benefits this brings to both safety and production. This is targeted at those who need a working understanding of the principles to support the compliance processes.

The third document (this document) is intended as a reference manual to provide more detailed guidance on “how to” implement Assurance and Verification, drawing on good practices provided through the participating companies in the UK Offshore Oil and Gas Industry for managing the suitability of plant and equipment. It is intended to provide an outline of the fundamental activities and relevant key principles which should be considered, raising a wider industry awareness of MAH management and sharing good tried and tested processes, without prescriptively and specifically defining how it should be done. This document is targeted at those with responsibility for developing and managing activities in support of Assurance and Verification.

To gain a full understanding of the regulatory requirements, reference should be made to the relevant Statutory Instruments and Guidance printed by the HSE and referenced in these documents.

It should be noted that following these guidelines will support, but not guarantee, compliance with UK law.
3. OFFSHORE UK LEGISLATION

The Offshore Installations (Safety Case) Regulations (OSCR)

Fixed and mobile offshore installations operating within UK waters are required to have a Safety Case which has been accepted by the HSE. The purpose of this document is to provide an overview that demonstrates both internally to the Duty Holder and co-venturers, and externally to the Regulatory Authorities, that a series of formal assessments have been made to ensure that the facilities’ design and the Company’s management systems are consistent with the requirement for safe and responsible operation, and that the Duty Holder has both “the ability and means to control major accident risks effectively”. It also provides the strategy for safe operation of the installation, which the Duty Holder intends to undertake to ensure compliance with relevant statutory provisions and risks to personnel are As Low As Reasonably Practicable (ALARP).

Full details of the specific requirements of the OSCR may be found in “A guide to the Offshore Installations (Safety Case) Regulations 2005”. The following presents some of the key requirements which have been paraphrased in order to provide a high level understanding of the expectations of these Regulations. These should not be considered to replace or fully represent the legislative requirements:

- An HSE accepted Safety Case is required to be in place for a production or non-production installation before it moves into, or commences operation in, the UK offshore sector

- The content of an Operations phase Safety Case principally requires the following:
  - full description of the installation and its boundary
  - description of its operations
  - numbers of personnel
  - description of plant and arrangements for control of well operations
  - descriptions of associated pipelines
  - details of how the Duty Holder complies with PFEER (see below)
  - details of arrangements for protecting personnel from toxic gas
  - details of arrangements for protection of personnel remaining on the installation during the escalation of hazardous situations arising from major accident related hazards, including Temporary Refuge (TR), routes and means for egress and evacuation, and means for control within the TR
  - details of how the Duty Holder will assure compliance with associated offshore Legislation: DCR, PSR, and in particular how the Duty Holder assures suitability of SCEs
  - descriptions of combined operations

- Demonstration of how the management system assures compliance with statutory provisions by the Company and arrangements for assuring contractor compliance. Arrangements for audit and report, and the identification of hazards with the potential to cause major accidents, and evaluation of the associated risks and provision of means provided to manage these

- Notifications are required to be submitted to the HSE for design, relocation or conversion of non-production installations, combined operations and well operations

- A revised Safety Case is required in some circumstances, but particularly where material change occurs, when directed by the HSE or for the dismantling phase of a fixed offshore installation

- A thorough review of Safety Cases is required every 5 years, or earlier if directed by the HSE. The review involves confirmation that the Safety Case as a whole continues to be fundamentally sound and is over and above the requirement to ensure that the Safety Case is up-to-date

- Duties are placed on the Licence Owner to ensure that any Operator appointed by them is complying with legislative requirements
3. OFFSHORE UK LEGISLATION

- The Verification Scheme is in place and operating as required
- Verification applies to the entire offshore installation. The definition of an offshore installation includes:
  - any part of a pipeline and associated apparatus within 500m
  - any devices beyond 500m, on which the safety of the installation depends
  - the plant and arrangements for the control of operations of a well
  - connected wells

The Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations (PFEER)

These Regulations require that the Duty Holder takes appropriate measures with a view to protecting personnel on the installation from fire and explosion and securing effective emergency response. The Duty Holder is required to:
- Perform an assessment to identify events which could give rise to a Major Accident involving fire or explosion; or the need for evacuation, escape or rescue to avoid or minimise the consequences of a Major Accident
- Evaluate the likelihood and consequences of such events
- Establish appropriate standards of performance to be attained by anything provided by these measures for:
  (i) ensuring effective evacuation, escape, recovery and rescue to avoid or minimise a Major Accident
  (ii) otherwise protecting persons from a Major Accident involving fire or explosion
  (iii) the selection of appropriate measures

The plant and equipment required to meet the needs of PFEER and defined in the Safety Case are normally also included in a common Written Scheme of Examination for completion of Assurance and Verification activities, as these are also SCEs.

The Offshore Installations and Wells (Design and Construction, etc) Regulations (DCR)

These Regulations require all wells to be covered by a Well Examination Scheme. The Duty Holder for these Regulations is the Well Operator.

Wells connected to an installation are deemed safety critical under the Safety Case Regulations and should be included in the Verification Scheme for the installation. However, both DCR and the Safety Case Regulations make it clear that the work carried out in one Scheme may be cited as part of the other Scheme and that duplication or repetition is not expected.

It is good practice for one Scheme to reference the other, eg the Verification Scheme ICP receives a copy of the well examination certificate even though they do not actually carry out any Verification activities on the well or well component parts. During its lifecycle, a well or its component parts may move between the Well Examination Scheme and the Verification Scheme. It is therefore essential that the Well Operator and any installation Duty Holder are aware at all times of which wells are covered by which Scheme.

“Well Examination” represents the activities performed by the Well Examiner, an Independent and Competent Person appointed by the Well Operator, to establish that wells are designed, constructed, commissioned, operated, maintained, modified (including interventions and workovers) and abandoned in accordance with the Design and Construction Regulations. Verification activities may be used as evidence in supporting well examinations.
3. OFFSHORE UK LEGISLATION

Major Accidents Hazard Management overview

The OSCR defines the concept of a Major Accident and this is paraphrased as follows:
• Death or serious personal injury due to fire, explosion or dangerous substance release
• Major damage to structure or plant, or loss of stability of the installation including well ‘blowout’, loss of containment or well control
• Helicopter collision
• Failure of diving operations life support systems, detachment of a diving bell or trapping of a diver
• Any event involving death or serious personal injury to five or more people

Major Accidents represent events which cause death, serious injury or major damage to plant. Such accidents cannot happen without exposure to hazards such as fire, explosion, toxic substances, weather, diving activity or ship movements. The OSCR requires that these hazards and the potential consequences of their realisation must be defined. Having established these scenarios, it is then possible to define strategies for minimising the risk of their occurrence through safety studies and the provision of careful design, key safety plant and equipment, and good operations and maintenance processes. These strategies effectively provide the basis by which risks are managed through elimination, prevention, detection, control, mitigation and finally rescue and recovery means.

Safety Critical Elements (SCEs)

The key safety plant and equipment required to manage risk is identified from these strategies and these are the “Safety Critical Elements”, defined in the Safety Case Regulations as:
“such parts of an installation and such of its plant (including computer programs), or any part thereof (a) the failure of which could cause or contribute substantially to; or (b) a purpose of which is to prevent, or limit the effect of, a major accident”

Major Accident Hazards (MAH) are established from a Hazard Identification study (HAZID). SCEs are identified from analysing those Hazards, and constitute the means required to manage the associated risks. Examples of SCEs and relevant associated equipment (sometimes referred to as sub elements), as shown in Figure 2 overleaf (Note that this is not intended to be a complete list).
### 3. OFFSHORE UK LEGISLATION

#### Identification of Safety Critical Elements

<table>
<thead>
<tr>
<th>Hazard Identification &amp; Assessment</th>
<th>Primary Major Hazards</th>
<th>Safety Critical Elements &amp; Sub Elements</th>
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<td>Process Containment</td>
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<td>Turbine Disc Failure</td>
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<td>Major Accident Register</td>
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**Process Flow**

Figure 2 - Identification of Safety Critical Elements
3. OFFSHORE UK LEGISLATION

Performance Standards

Having identified the key items of safety critical plant and equipment (the SCEs), it is now prudent to define the functions they are required to perform and confirm the actual equipment is capable of consistently and continuously performing those functions. This is defined in the Performance Standards (one for each SCE) which is the commonly accepted method of describing what an SCE must achieve. SCEs are assessed against Performance standards through the Assurance and Verification activities, to give an adequate level of confidence that they will fulfil their intended purpose whenever required. Refer to the Performance Standards section (Page 17) for further information on Performance Standard setting.

“Assurance” represents the activities performed to ensure SCEs meet Performance Standards. This includes activities in all phases of the lifecycle and may involve activity by the design contractors in the design, procurement and construction phases which the Duty Holder needs to monitor to ensure the SCEs are “initially” suitable.

During the operational phase, the Duty Holder uses preventive maintenance strategies including inspection, planned maintenance and testing to ensure that SCEs are consistently and continuously meeting the Performance Standard requirements. Assurance also includes design and construction of modifications and the management of change to manage the impact on SCEs, and this is normally controlled through the use of a Management of Change (MOC) process.

“Verification” represents the activities, in addition to Assurance, which are performed by an ICP, appointed by the Duty Holder, to confirm whether the SCEs will be, are, and remain suitable, or are adequately specified and constructed, and are being maintained in adequate condition to meet the requirements of the Performance Standards.

The steps involved in Major Accident Hazard Management outlined above are illustrated in Figure 3 below.

Figure 3 - Major Accident Hazard Management
In summary, Major Accident events should be identified in the Safety Case together with the means used to prevent, detect, control, mitigate, rescue or help recover from a Major Accident which effectively become the SCEs. Performance Standards define the specific functions which SCEs must perform, and Assurance activities support the demonstration of continuous suitability to perform those functions.

All personnel should develop a level of understanding of how their safety is assured through the Safety Case, and the reliable performance of SCEs in accordance with Performance Standards in performing key functions to minimise the consequences of realised MAHs. This understanding will help personnel appreciate the importance of the SCEs and help understand how they can support and assure safety within their own job roles, bringing benefits in safety to all involved.
Based on historical findings from Major Accidents, such events do not occur solely as a result of a single failure of plant or one individual's mistake. Such accidents require the failure of a combination of processes, plant integrity and people activities, often referred to as the barriers between the hazard and the occurrence of an accident.

Many initiatives have been undertaken to develop models to describe how the complex interaction of safety systems can avoid the initiation and escalation of an event leading to an accident.

The key and common building blocks amongst these concepts are the identification of:

<table>
<thead>
<tr>
<th>PROCESS</th>
<th>the setting of standards and expectations through management processes and procedures, and;</th>
</tr>
</thead>
<tbody>
<tr>
<td>PEOPLE</td>
<td>the organisational culture established, the values adopted and the way people behave and the functions they perform, and;</td>
</tr>
<tr>
<td>PLANT</td>
<td>the provision of suitably designed and constructed plant to adequately meet defined needs and the condition in which it is maintained.</td>
</tr>
</tbody>
</table>

Together, if managed effectively, these building blocks can reduce the risk of occurrence of a Major Accident.

Combined individual failures provide a route for the initiating hazard to become an accident. Intervention at any one of these failures may have arrested the event from occurring or reduced the consequences; because each identified failure mechanism represents a barrier between the hazard and consequential harm. Some examples of plant barriers (SCEs) are shown below and the holes in the barriers reflect a path or route through which the hazard is realised. This is referred to as the “Swiss Cheese model” and is the concept defined by James Reason. Figure 4 refers to a specific Loss of Containment Major Accident Event.
4. MANAGING MAJOR ACCIDENT HAZARDS THROUGH BARRIERS

An example of how degradation of barriers (illustrated as holes) might provide a path to cause a Major Accident is explained below, where each sentence describes an impaired barrier through which the hazard moved and escalated. When reading, reflect on how a fully operating barrier without defects (or holes), might have prevented an accident or reduced the magnitude of its consequences:

A gas flow line was incorrectly assessed to identify likely areas where corrosion might occur and the area where corrosion actually occurred was not examined. Following completion of the inspection, the Engineer assessing the results did not have the competence / experience to recognise this. The corrosion eventually led to a breakout of gas (PREVENTION barrier failure).

A number of gas detectors in the area had been inhibited due to ongoing work in the area. Persons responsible for assuring temporary battery-operated detectors did not adequately check their function (DETECTION barrier failure).

Electrical equipment normally designed to avoid electric discharges had not been maintained or incorrectly maintained, leading to a spark which ignited the gas in the area (CONTROL barrier failure).

The ensuing fire escalated because the water deluge piping and nozzles provided were blocked by rust and scaling, and failed to perform as intended (MITIGATION barrier failure).

The above scenario could continue into the later stages of the developing accident to identify further barriers which may succeed or fail, such as communication systems, emergency shutdown of plant, process blowdown to reduce the gas inventory available to the accident, HVAC dampers to avoid ingress of smoke to the Temporary Refuge, evacuation and escape routes, and throughout these, the defined management procedures which document actions to be taken, and the functions people do or do not do.

Each stage reflects the failure of a barrier, whether People, Process or Plant and this demonstrates the importance of maintaining the health of such barriers to avoid the initiation and escalation of events leading to Major Accidents.

Good barrier performance can be achieved through the adoption of well written performance standards and assurance and verification procedures, adhered to by people who are competent for their defined roles in maintaining and assuring the performance of safety critical equipment. The following sections will describe in more detail how this can be achieved.
Introduction

Having identified and agreed the appropriate SCEs according to the process described in the previous section, it is necessary to define what they must do. The most commonly accepted process to effectively define this is through the use of Performance Standard templates with specific and tailored criteria to ensure that there is consistency and alignment regarding what an SCE must achieve to fulfil its role in hazard management.

What is a Performance Standard?

PFEER Guidance Para 45 states:

A performance standard is a statement, which can be expressed in qualitative or quantitative terms, of the performance required of a system, item of equipment, person or procedure, and which is used as the basis for managing the hazard - eg planning, measuring, control or audit - through the lifecycle of the installation. The regulation does not specify what performance standards should be - that is for the Duty Holder to decide, taking account of the circumstances on the particular installation.

This means that any SCE needs an associated Performance Standard which describes the essential requirements that must be maintained or provided on demand, throughout the lifecycle of the installation.

For a Performance Standard to be suitable it should satisfy all of the following conditions:

a) Scope and functionality of the system shall be described / defined
b) Criteria shall be specified for each safety critical component and these criteria should have a clearly defined (technical) basis
c) Parameters shall be measurable / auditable with defined acceptance criteria
d) Measured parameters shall provide evidence of the ability of the component / system to meet its minimum requirements and hence to prevent or limit the effect of a Major Accident

Why do we need Performance Standards?

PFEER Reg.5.2(c) specifically refers to Performance Standards, as follows:

(2) An assessment (of the Major Accident Hazards) shall consist of-
…(c) the establishment of appropriate standards of performance to be attained by anything provided by measures for -
(i) ensuring effective evacuation, escape, recovery and rescue to avoid or minimise a major accident; …

SC Regulation 2.5 states:

A Verification Scheme is a reference to a suitable written scheme for ensuring, by means described in paragraph (6), that the safety-critical elements and the specified plant -
(a) are or, where they remain to be provided, will be suitable; and
(b) where they have been provided, remain in good repair and condition.

Performance Standards:

• Are a legal requirement for PFEER-related elements. They are also the commonly adopted means to meet the requirements of the Safety Case Regulations for ensuring SCE suitability

• Provide a robust means to manage our major hazards and their associated risks

If each SCE meets its Performance Standard at all times, the likelihood of a Major Accident on a facility is reduced. The reverse is also true. Failure of an SCE to meet its defined Performance Standard increases the likelihood and / or the potential consequences of a Major Accident occurrence.

Dangers arise from a poorly defined Performance Standard. If it is difficult to measure, if important aspects / issues are missing, or if it is difficult to understand, the Performance Standard may be ineffective or even ignored, increasing the possibility of a Major Accident.
5. PERFORMANCE STANDARDS

How are Performance Standards created?

Performance Standards and SCEs are commonly grouped by Barrier Type; namely Prevention, Detection, Control, Mitigation and Emergency Response; meaning that these provide barriers of protection from Major Accident Hazards, as shown in Figure 4. This is the basis used in building the following guidance on developing Performance Standards.

Which Phases of the Lifecycle do Performance Standards cover?

The identification of Safety Critical Elements is a key building block within the installation’s Safety Case and a Performance Standard should be developed for each SCE. Appropriate Performance Standards are required for SCEs over their full lifecycle and it is important to ensure safe transition between lifecycles phases:

- Design
- Transportation and Construction (onshore and offshore)
- Hook-up and Commissioning
- Operations
- Modifications
- Repair
- Life Extension
- Preservation
- Decommissioning and Abandonment
- Procurement (all lifecycle phases)

What should be considered for an effective Performance Standard?

Performance Standards need to be defined in a consistent and logical manner. It is likely that more than one parameter will be needed to detail the required performance of the SCE as a barrier. The codes, standards and specifications used in the original design of SCEs should be identifiable from the Performance Standards so that suitability can be maintained throughout the asset’s life. Any other related key documents should also be referenced in the Performance Standard.

PFEER, ACOP 5, Para 58 States:
Setting performance Standards for measures is a crucial aspect of the assessment process. Performance Standards should relate to the purpose of the system, item of equipment, procedure etc which they describe. They may be described in terms of functionality, survivability, reliability and availability (FARSI). They should be measurable and auditable.

Along with interactions with other SCEs, this is commonly known as the FARSI model for Performance Standards and the following paragraphs provide a brief description and explanation. It should be noted that the examples are illustrative only and additional criteria may apply to specific SCEs.

Functionality - What is it required to do?
Functionality defines the key duties that the SCE is required to perform. The minimum level at which that function is achieved must also be defined. Criteria is considered ‘measureable’ where it is possible for a person carrying out an assurance activity to clearly understand what the critical requirement is, and to be able to measure or observe that the criteria is being achieved.

During the operational phase of the installation, the Performance Standard has to reflect how it shall be assured that the SCE is maintained in the minimum acceptable condition. This may not be the same as the design criteria - an acceptable level of safe degradation should be defined.
5. PERFORMANCE STANDARDS

For ‘static’ or ‘passive’ systems (structures, containment, lifting equipment etc) measurable criteria for operational suitability may be expressed in terms of the maximum allowable degradation that can be tolerated. This may derive from international standards, Duty Holder’s anomaly classification criteria, industry guidelines or other ‘best practice’.

For ‘active’ systems it is likely that performance can be clearly quantified and confirmed by function test (active fire system discharge rates, instrument alarm and trip set points, ESD valve closure time and leakage rates etc). Detailed functional analysis may be required to determine the failure modes (including computer systems) which lead to loss of critical functionality and the means of identifying them. Equipment that is ‘self-testing’ may make functional failure evident.

For SCEs such as personal survival or escape equipment where continual suitability is primarily achieved by original design specification, it may be more practical to define periodic service or re-certification intervals. Defining a ‘fixed life’ for equipment replacement may also be appropriate.

The following example is given only to demonstrate a single Functional criteria:

<table>
<thead>
<tr>
<th>FUNCTION</th>
<th>CRITERIA</th>
<th>ASSURANCE REFERENCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>UPS shall maintain power to the defined emergency systems.</td>
<td>UPS systems shall provide a back-up power supply to enable continued operation of the following emergency systems in the event of failure of normal and essential power. The following systems shall have a minimum duration of XX minutes. Shutdown Systems (XX Amperehours) Fire and Gas (XX Amperehours) Emergency related Telecoms (XX Amperehours) PA/GA Systems (XX Amperehours)</td>
<td>Duty Holder should provide details of assurance activities or specific cross references to PMR database tasks.</td>
</tr>
</tbody>
</table>

**Availability** - For what proportion of time will the equipment be available to perform on demand? (Alternatively, the ability for the system to provide access to its resources in a timely manner for a specified duration.)

Availability is concerned with the ability of the SCE to meet its intended function, including its interaction with other SCEs, eg an electrically driven fire pump can only be deemed available if the power can be provided to the pump from the emergency switchboard and the pump can deliver the required flow rate to the distribution system. If any part of the system is defective, it will cause the pump to have reduced Availability. There is often a close correlation between Reliability and Availability.
Availability may be better understood and measureable where it is described in terms of the amount of time it is tolerable for the critical functions to be unavailable, or to describe mitigation measures that need to be implemented where Availability is less than 100%.

Availability should be considered during design of an SCE, ie the designer should specify how the system will manage failure modes and therefore how it will remain available, ie by providing diverse systems and redundancy.

Quantitative risk assessments are often carried out to assist in defining the design requirement. The result of such a study will produce a target, eg 97.8% availability which equates to an acceptable annual downtime of approximately 8 days. In theory, this may be a good basis for design, but how shall this remain meaningful during operations? Is it safe to state that it would be acceptable to continue operation with an essential safety system out of operation during those days? In practice, it is rarely possible to carry out a meaningful volume of testing to capture sufficient data to demonstrate that such targets are met.

In general terms, when a system is safety critical, the availability target should be 100%. In practice, the SCE may never achieve 100% but if (or rather when) an SCE fails in some manner (note the PS should define through measurable criteria when such a failure occurs), the immediate shortcoming has to be addressed through risk assessments and through the Safety Management System. The Duty Holder should then aim for improvement, ie how to prevent similar failures in the future.

Where appropriate measures have been set, it is necessary to ensure that the means to capture required information are defined in order to assess Availability. This may be through clear recording of failed components, downtime records and safety critical risk assessments.

The example given below describes the overall goal and the design criteria which have been used to meet this. It is a requirement to assure / verify that this specification remains available, eg both sides of the public address (PA) system are being examined for continued effectiveness and Availability of the complete system remains at 100% (ie failures of individual components may be considered acceptable dependant on the impact on the ability of the system to operate on demand).

The following example is given to demonstrate possible Availability criteria:

<table>
<thead>
<tr>
<th>SCE – COMMUNICATION SYSTEMS</th>
<th>AVAILABILITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>FUNCTION</td>
<td>CRITERIA</td>
</tr>
<tr>
<td>The PA/GA System shall</td>
<td>The PA system has been designed with built in redundancy. The PA/GA shall be a dual (sub-systems A &amp; B) system, with each sub-system being capable of independently providing audible alarms, visual alarms and speech in all areas, such that no single failure can impair both sub-systems. Each sub-system shall be fed from independent Uninterruptible Power Supplies. Any failure which affects the ability of BOTH systems to operate shall be subject to immediate safety critical risk assessment and appropriate mitigating measures implemented.</td>
</tr>
</tbody>
</table>
5. PERFORMANCE STANDARDS

Reliability - How likely is it to perform on demand?
(Alternatively, the ability of an item to perform a required function under given conditions for a specified time interval.)

Those SCEs for which it is required to measure Reliability during operations should be identified at the design stage. Reliability targets are set during the design phase based upon safety studies carried out in support of the Safety Case. These should be measured during the operations phase to confirm compliance.

In operations, a target for Reliability is practical for ‘active’ systems that need to perform critical functions in response to a Major Accident (e.g., Fire & Gas detection, fire pump starting, ESD valve actuation etc.). Reliability targets are also appropriate for systems which actively monitor the status of other systems (e.g., alarms for loss of area pressurisation, annulus pressure monitoring, mooring tension, bilge flooding etc). Reliability targets are not appropriate for passive systems such as structure or passive fire protection.

Any critical function that has a demand to operate in response to a Major Accident must have a low probability of failure to meet that demand. The probability must be so low that the risk is considered ALARP.

High Reliability is achieved through the initial design specification of equipment (i.e., robust, simple design, self-diagnosis, redundancy etc).

Performance Standard criteria for Reliability can be expressed in terms of Probability of Failure on Demand (PFD), Safety Integrity Level (SIL) or Mean Time Between Failure (MTBF). The frequency and results of testing must be such that the Reliability target is confirmed.

During operations, the ability to meet this is demonstrated by functional testing at an appropriate interval. From these tests, accurate data must be recorded and reviewed in detail to assess if the required Reliability is being achieved. If the required level of Reliability is not being achieved, appropriate action must then be taken to improve it. This may include system redesign, amendment of test intervals or revision of the maintenance strategy.

Targets for Reliability in operation may not be possible for some SCEs as there may be no possibility to collect sufficient data to assure the target is met. In cases such as deluge valves or fire pumps there should be a general expectation that they shall operate on demand every time. It is vital that Technicians understand this concept and record when failures are observed during routine testing, i.e., that the reliability of an SCE is compromised when they have to carry out corrective maintenance in order for the intended function to complete its action.
5. PERFORMANCE STANDARDS

### SCE – FIRE & GAS

#### RELIABILITY

<table>
<thead>
<tr>
<th>FUNCTION</th>
<th>CRITERIA</th>
<th>ASSURANCE REFERENCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>The entire Fire &amp; Gas system shall meet defined Reliability.</td>
<td>The Fire &amp; Gas Detection system design and engineering shall be carried out and performed to meet requirements of SIL ratings as defined within IEC 61508.</td>
<td>Duty Holder should provide details of assurance activities or specific cross references to PMR database tasks.</td>
</tr>
<tr>
<td></td>
<td>F&amp;G System processor/controller will be SIL?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>F&amp;G Loops in defined high risk areas will be SIL?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>F&amp;G Loops in defined low risk areas will be SIL?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(ref to QRA study for target SIL rating)</td>
<td></td>
</tr>
</tbody>
</table>

### SCE – ESD SYSTEM

#### RELIABILITY

<table>
<thead>
<tr>
<th>FUNCTION</th>
<th>CRITERIA</th>
<th>ASSURANCE REFERENCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>ESD Valves for hydrocarbon risers shall have a probability of failure on demand less than xx% (eg 2%).</td>
<td>ESD Valves are designed to [STANDARD] Testing carried out according to functional requirements, any failure to close during testing are reviewed at the time of test according to SCRA procedures, appropriate mitigation measures shall be agreed with TA within xx time.</td>
<td>Duty Holder should provide details of assurance activities or specific cross references to PMR database tasks.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reference to QRA study for target reliability requirement.</td>
</tr>
</tbody>
</table>

Survivability - How will the system perform post event, eg after fire, explosion, ship impact, dropped objects, extreme weather etc?

The Performance Standard criteria for Survivability must be defined if the SCE is required to operate in the event of a Major Accident and should state for how long the system should continue to be effective. Each SCE should be considered against the MAH defined in the Safety Case. Does the MAH have the possibility to impair the ability of the SCE to operate? If so, how shall this be mitigated against?

Consider the following examples:
- Jacket structures need to be able to withstand ship collision and the highest expected environmental conditions
- Module walls need to have fire / blast resistance
- The time which structures need to survive the defined fire scenarios
- Fire & Gas system shall survive fire scenarios, eg cabling shall be fire resistant, the F&G control system should be protected by location in the Temporary Refuge
Survivability is often determined at the design stage and initial suitability assessment of the equipment (physical location, fire rating, mechanical strength, fatigue life etc).

The following examples are given to demonstrate possible Survivability criteria:

<table>
<thead>
<tr>
<th>Event</th>
<th>Component</th>
<th>Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>Extreme Weather</td>
<td>All Reference to structural design report based on Metocean data for specific location.</td>
<td>Jacket structures shall withstand the specified (XXX-year return) extreme environmental conditions specified in the site specific Metocean report without collapse.</td>
</tr>
<tr>
<td>Fire and Explosion</td>
<td>Primary structure within X metres of the YY deck. Reference to Fire Risk Assessment.</td>
<td>H120 Passive Fire Protection is applied to structural members in the defined area.</td>
</tr>
</tbody>
</table>

**Interactions** - It is useful to define other SCEs which are required to function in order for the one in question to also operate effectively.

Systems of Safety Critical Elements are often dependent upon each other in order that the MAH is mitigated. Consider the following examples:

- Hydrocarbon containment relies on Structural elements to support the containing equipment and piping
- Structural elements rely on Passive Fire Protection to ensure they meet Survivability criteria
- Fire & Gas systems rely on Emergency Power (UPS) to ensure they provide protection during power outage or ESD
- Electrical ignition prevention is a system relied upon by others to ensure that safe operation is continued in potentially flammable atmospheres

The following examples are given to demonstrate potential Interactions:

<table>
<thead>
<tr>
<th>SCE – TEMPORARY REFUGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>INTERACTIONS</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SCE</th>
<th>Reason for Interaction / Dependency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Structures</td>
<td>To provide mechanical integrity of the Temporary Refuge. To retain sufficient integrity to preserve positive pressure following loss of HVAC.</td>
</tr>
<tr>
<td>Communications and Alarms</td>
<td>To inform personnel of the need to muster and / or evacuate. To provide communication facilities with aircraft, shipping (including the Emergency Response &amp; Rescue Vessel) and external rescue agencies.</td>
</tr>
<tr>
<td>Escape and Evacuation Routes</td>
<td>To enable access to and egress from the Temporary Refuge from all areas. To provide sufficient illumination for personnel to muster in safety, don their survival equipment and evacuate / escape. To provide sufficient illumination for persons in command of the emergency to be able to perform their duties.</td>
</tr>
</tbody>
</table>
5. PERFORMANCE STANDARDS

General Considerations during Setting of Performance Standards

The following considerations should be observed in the setting of Performance Standards:

- Each criteria shall be justified:
  - it should be encouraged to use and reference design standards and codes where this is relevant
  - Safety Case supporting studies such as Fire Risk Analysis (FRA) and Quantitative Risk Analysis (QRA) should be reflected in the Performance Standards criteria, eg FRA will provide information for the required fire water demand in respect of the largest potential scenario

- Clearly measurable criteria, which can be confirmed during routine operations, maintenance, testing or inspection, are needed. Where acceptance criteria are obscure or ambiguous they cannot practically be assured. This can lead to confusion and loss of confidence in the SCE management process

- Lifecycle phases shall be separately considered, but may be combined into a single document

- The decision to have single or separate Performance Standard documents for each phase is a matter for individual Duty Holders, however, it should be noted that the HSE recommend a single document from cradle to grave. A balance between retaining and making readily available important details of the original design against providing too much design detail to personnel in the operational phase needs to be made. In operations, more concise, specific, and measureable criteria are required

- Good practice is to align maintenance management activities directly to performance standard criteria, ensuring that specific failure limits are defined within the routines

- The means by which Performance Standard criteria is assured should be identifiable from the Performance Standard

Review of Performance Standards

Performance Standards should be periodically reviewed. The purpose of this is to:

- Incorporate new learnings from within the Duty Holder’s own organisation, the ICP and other industry developments
- Consider if they are still suitable as required by the Regulations

Increased benefit can be achieved through the use of mixed teams of onshore and offshore personnel.

Suitability can change over years as new knowledge is obtained and codes and standards also change. The Duty Holder should ensure that they met these new standards / codes or demonstrate that it is not reasonably practicable to meet them

Performance Standards should also be reviewed when operating parameters on the installation change, eg additional wells bringing more hydrocarbons or sour service, higher POB due to additional living quarters etc.

Review of Performance Standards should be carried out in conjunction with the Safety Case thorough review or when there is a significant change to the asset such that a Safety Case revision is necessary. Examples of such a change include a significant increase in hydrocarbons production as a result of ongoing field developments or the addition of production from third parties or additional satellite fields.

Over time, additional criteria may be necessary to address failure modes that may emerge or develop as a result of the ageing processes which impact on assets in later life.
5. PERFORMANCE STANDARDS

Performance Standards – Detailed Example for Operations Phase

| System Requirements | To provide, for a defined endurance period, • a temporary place of refuge for personnel during a major accident
|                     | To provide essential life support for sheltering personnel
|                     | To provide a safe place of muster
|                     | To provide essential command and control facilities for platform management to enable effective emergency response

<table>
<thead>
<tr>
<th>FUNCTION</th>
<th>CRITERIA</th>
<th>ASSURANCE REFERENCE</th>
</tr>
</thead>
</table>
| The TR shall contain adequate space for all personnel on board to muster. | – The primary muster area, located at xx within the TR is sized suitable for 100% POB (xx persons) based on xxm2/person + xxm2 for xx stretcher casualties
|                           | – Muster area shall be maintained free of obstructions
|                           | Criteria Reference, eg Safety Case, Emergency Escape & Rescue Analysis, SOLAS Chapter III |
|                          | This column will be used to define the assurance means employed by the Duty Holder to assure themselves of the continued good condition of the particular criteria. Details of Assurance expectations are addressed later in this guidance document. |

| The TR internal boundaries shall provide adequate integrity against internal fire events. | – Internal boundaries including doors and penetrations within the TR are fire rated to comply with SOLAS Chapter II-2 Reg.9
|                                                                                     | – Boundary doors shall be self closing
|                                                                                     | – Air ducts and electrical penetrations shall also be insulated according to the requirements of above regulation with certified fire dampers and electrical/pipes penetrations used
|                                                                                     | Ref. SOLAS Chapter II-2 Regulation 9 |
|                                                                                     | The assurance may be defined by reference to Planned Maintenance Routines specific to the criteria. (Please note - It is not intended to define specific assurance measures within this part of the document) |
### 5. PERFORMANCE STANDARDS

**SCE – TEMPORARY REFUGE (TR)**

<table>
<thead>
<tr>
<th><strong>The TR external boundaries shall be protected against the ingress of harmful smoke or gas.</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>- Boundary doors are provided with an airlock to maintain positive pressure of xx bar within TR</td>
</tr>
<tr>
<td>- Air ducts are provided with fail safe fire dampers to protect against smoke and gas ingress and maintain the positive pressure within the TR. Dampers should close within xx seconds of input signal</td>
</tr>
<tr>
<td>- Fire dampers shall have remote position indication in the emergency control station</td>
</tr>
<tr>
<td>- Inspection hatches shall be provided to allow ease of inspection / maintenance of all boundary fire dampers</td>
</tr>
<tr>
<td>Reference, eg Safety Case, Emergency Escape &amp; Rescue Analysis, SOLAS Chapter II-2 Regulation 9; HSE Offshore Information Note 1/2006</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>The TR shall support key control and communications functions for a minimum duration of one hour.</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>The TR boundaries shall enclose and effectively protect the following (examples only):</td>
</tr>
<tr>
<td>- Emergency Telecoms Room</td>
</tr>
<tr>
<td>- Main Control Room for critical systems</td>
</tr>
<tr>
<td>- Emergency Command Centre</td>
</tr>
<tr>
<td>Ref: PFEER Regulation 12 &amp; OSCR Schedule 2 &amp; 3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>AVAILABILITY</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FUNCTION</strong></td>
</tr>
<tr>
<td>Muster area availability will be 100%</td>
</tr>
<tr>
<td>The TR impairment frequency shall not exceed xx per year.</td>
</tr>
</tbody>
</table>
## 5. PERFORMANCE STANDARDS

### SCE – TEMPORARY REFUGE (TR)

#### RELIABILITY

<table>
<thead>
<tr>
<th>FUNCTION</th>
<th>CRITERIA</th>
<th>ASSURANCE REFERENCE</th>
</tr>
</thead>
</table>
| Fire Dampers   | Shall have a reliability / ability to operate on demand of xx%  
All assurance routine recording should include failures corrected at time of test  
Ref: QRA study & SIL assessment                                                                 | Additional routine may be required here for review of actual testing records to assess systems ability to operate on demand                                                                                     |

#### SURVIVABILITY

<table>
<thead>
<tr>
<th>EVENT</th>
<th>COMPONENT</th>
<th>CRITERIA</th>
<th>ASSURANCE REFERENCE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fire &amp; Explosion</td>
<td>External boundaries</td>
<td>Designed and maintained to H120 fire rating and for explosion blast of 0.25 bar overpressure</td>
<td>Refer to SCE for Passive Fire Protection for assurance</td>
</tr>
</tbody>
</table>

#### INTERACTIONS

<p>| | | | |</p>
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</thead>
<tbody>
<tr>
<td>Fire &amp; Gas</td>
<td>Protection to F&amp;G System provided by TR, F&amp;G system provides signals to fire dampers to retain integrity of TR</td>
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<tr>
<td>PFP</td>
<td>PFP to provide fire &amp; blast protection for survivability of TR</td>
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<tr>
<td>ESD</td>
<td>ESD system protected by TR</td>
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<tr>
<td>Emergency Communications</td>
<td>Emergency communications protected by TR</td>
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<tr>
<td>Emergency Power</td>
<td>Emergency power required to provide power to essential TR systems in event of an incident</td>
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</tbody>
</table>

### Guidelines: Criteria to be considered for each SCE

The following tables are provided as a general informative guideline on parameters which may be considered to be defined within FARS1 criteria. This is organised into barrier groupings and listed for each Safety Critical Performance Standard. It is not intended to be a fully developed example set of Performance Standards; merely a list of parameters which can be defined therein.
## Prevention SCE Barrier table

<table>
<thead>
<tr>
<th>SCE Example</th>
<th>Functions</th>
<th>Reliability</th>
<th>Availability</th>
<th>Survivability</th>
<th>Interdependence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Process Containment</td>
<td>- Mechanical strength/integrity - Limits for corrosion, erosion, fatigue, coating breakdown, mechanical damage, water ingress to insulation, security of supports etc.</td>
<td>By design - operational target not appropriate as failure cannot be tolerated.</td>
<td>By design - operational target not appropriate. To be 100% available in operation to avoid loss of containment</td>
<td>- Draped object resistance/protection - Blast resistance - Pool and jet fire resistance - Environmental criteria</td>
<td>- Topside Structures to provide support and impact protection - Delegue or Passive Fire Protection to meet Survivability criteria</td>
</tr>
<tr>
<td>Well Integrity</td>
<td>- Mechanical strength/integrity of wellheads and Christmas trees - Internal and external leakage - Closure time for actuated shutdown valves - Calibration of annulus gauges - Condition of wellhead control panel/PDU - Condition, rating and operation of fusible loop</td>
<td>Identify Safety Integrity Levels (SIL) for operation of actuated tree valves.</td>
<td>Identify Safety Integrity Levels (SIL) for operation of actuated tree valves.</td>
<td>- Draped object resistance/protection - Blast resistance - Pool and jet fire resistance - Environmental criteria</td>
<td>- EOS System to monitor well status and initiate trip of tree valves - Well Examination Scheme - Fire &amp; Gas to interface with fusible loop - Deluge systems to meet Survivability criteria</td>
</tr>
<tr>
<td>Hull Integrity</td>
<td>- Girder strength - Limits for corrosion, erosion, fatigue, coating breakdown etc. - Condition of deck hatches and water/weather tight doors - Operation of remote door position indication - Hull penetration valves - integrity, operation and position indication (remote and local) - Cathodic protection systems</td>
<td>Identify Safety Integrity Levels (SIL) for operation of actuated hull penetration valves.</td>
<td>Identify Safety Integrity Levels (SIL) for operation of actuated hull penetration valves.</td>
<td>- Design strength to withstand ship collision - Draped object resistance/protection - Blast resistance - Pool and jet fire resistance - Environmental criteria - Operation of position monitoring systems following loss of main power</td>
<td>- Ballast system to maintain hull stability - Inert Gas system to prevent cargo tank overlander pressure - Navigational Aids to avoid shipwreck collision - Safeguarding Instrumentation to prevent collision during Shuttle Tanker approach and offloading operations - Emergency power system to supply position monitoring system</td>
</tr>
<tr>
<td>Jacket and Topside Structures</td>
<td>- Mechanical strength/integrity - Limits for corrosion, erosion, fatigue, coating breakdown etc. - Structural elevation - Air gap required between wave crests and the underside of topside structures - Limits for sour and debris at foundations - Limits for weight and marine growth</td>
<td>By design - operational target not appropriate as failure cannot be tolerated.</td>
<td>By design - operational target not appropriate. To be 100% available to avoid loss of integrity.</td>
<td>- Design strength to withstand ship collision - Draped object resistance/protection - Blast resistance - Pool and jet fire resistance - Environmental criteria</td>
<td>- Navigational Aids to avoid shipwreck collision - Delegue or Passive Fire Protection to support Survivability criteria</td>
</tr>
<tr>
<td>Lifting Equipment</td>
<td>- Mechanical strength/integrity - Overload protection - Ropes - security of terminations and discard criteria</td>
<td>By design - operational target not appropriate as failure cannot be tolerated.</td>
<td>Comes to be 100% available during lifting operations - Action on loss of power - Weather limits for crane operations</td>
<td>- Environmental criteria</td>
<td>- Navigational Aids to avoid shipwreck collision</td>
</tr>
<tr>
<td>Helideck</td>
<td>- Load limits - Dimensions (‘D’ value) - Layout and markings - Identification of permanent obstructions - Means to prevent temporary obstructions</td>
<td>By design - operational target not appropriate as failure cannot be tolerated.</td>
<td>By design - operational target not appropriate. To be 100% available to avoid loss of integrity.</td>
<td>Helideck protected from blast overpressure by location (by design) - Helideck to resist design scenario helicopter crash landings - The helideck is not expected to remain usable in scenarios involving the generation of large amounts of smoke or high levels of thermal radiation - Environmental criteria - Wave-overflowing beams to prevent landing during emergency (event escalation)</td>
<td>- Topside Structures to provide support - Delegue systems to handle fuel leakage/pillow - Active fire protection systems in the event to helicopter collision - Crash box and personal protective equipment provided to helideck crew - Escape routes for access and egress - Navigational Aids to avoid aircraft collision</td>
</tr>
<tr>
<td>Mooring System</td>
<td>- Mechanical strength/integrity - Limits for material loss, corrosion, erosion, fatigue, coating breakdown, mechanical damage etc. - Marine growth limits - Design limits for tension - Indication of tension (input to heading control system) - Excursion limits and alarms</td>
<td>Safety Integrity Levels (SIL) to be defined for position and mooring monitoring systems (test intervals to ensure SIL level is achieved).</td>
<td>By design - operational target not appropriate. To be 100% available to avoid loss of integrity.</td>
<td>- Environmental criteria</td>
<td>API SPEC 2F - Specification for Mooring Chain</td>
</tr>
</tbody>
</table>

- **ISO 19900 (Offshore Structures - General Requirements)**
- **ISO 19901-5 (Weight Control)**
- **API SPEC 6A - Specification for Wellhead & Xmas Tree Equipment**
- **ISO 19901-9 (Weight Control)**
- **ISO 13535 (Hoisting Equipment - Specification)**
- **ISO 13534 (Inspection, Maintenance, Repair and Remanufacture of Hoisting Equipment)**
- **API SPEC 2C - Specification for Offshore Pedestal Mounted Cranes**
- **ISO 13354 (Firefighting and Fire Protection Equipment)**
- **ISO 4509 (Cables Wire Rope)**
- **HSE Offshore Helideck Design Guidelines**
- **CAP 437 (CAA - Offshore Helicopter Landing Areas - Guidance on Standards)**

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**Note:** The image also includes a checkmark symbol, indicating a step change in safety. The context suggests that this is a part of a document related to assurance and verification guidance for offshore operations.
### Detection SCE Barrier table

<table>
<thead>
<tr>
<th>SCE Example</th>
<th>Functions</th>
<th>Reliability</th>
<th>Availability</th>
<th>Survivability</th>
<th>Interdependence</th>
<th>Example Associated Standards</th>
</tr>
</thead>
</table>
| Fire & Gas Detection | - Detection methods and types (including MAC)  
- Functionality (Reference Cause & Effects)  
- Set-Points for alarm & trip activation  
- Time limits for instrument response  
- Failure modes  
- Logic Solver voting  
- Status Indication (what & where)  
- Electromagnetic compatibility  
- Safety Integrity Levels (SIL) to be identified (test intervals to ensure SIL levels are achieved)  
- Overall F&G system availability of XX.X%  
- Provision of status indication within Temporary Refuge  
- Fault monitoring - provision of alarms on field detector failure  
- Fire rating for field cables  
- Ingress Protection (IP) rating for field devices  
- Fire detector response time should activate and initiate executive actions before direct exposure destroys detector or cabling.  
- Operation of loss of main power supplies  
- UPS systems supplies Fire & Gas system on loss of main power  
- Ex Certification ensures electrical equipment is suitable for operation in hazardous areas  
- IEC EN 61508 (Functional Safety of Electronic Safety-related Systems)  
- Energy Institute Model Code of Safe Practice Part 14 (Inspection and Testing of Protective Instrumentation) | | | | | | |
| ESD System (Inputs) | - Process sensor types (manual and automatic)  
- Functionality - Set-Points for alarm & trip activation (Reference Cause & Effects)  
- Time limits for instrument response  
- Instrument response time  
- Failure modes  
- Operation of ESD timers  
- Operation of blowdown system sequencing logic  
- Logic Solver voting  
- Status Indication (what & where)  
- Electromagnetic compatibility  
- Safety Integrity Levels (SIL) to be identified (test intervals to ensure SIL levels are achieved)  
- Overall ESD system availability of XX.X%  
- Provision of status indication within Temporary Refuge  
- Fault monitoring - provision of alarms on field detector failure  
- Fire rating for field cables  
- Ingress Protection (IP) rating for field devices  
- Operation of loss of main power supplies  
- UPS systems supplies Fire & Gas system on loss of main power  
- Ex Certification ensures electrical equipment is suitable for operation in hazardous areas  
- IEC EN 61508 (Functional Safety of Electronic Safety-related Systems)  
- Energy Institute Model Code of Safe Practice Part 14 (Inspection and Testing of Protective Instrumentation) | | | | | | |
| Safeguarding Instrumentation | - Rotating equipment Over-temperature / vibration protection  
- Lubrication/seal oil status monitoring systems  
- Heading control systems  
- Safety Integrity Levels (SIL) to be identified (test intervals to ensure SIL levels are achieved)  
- Fault monitoring - provision of alarms on field detector failure  
- Fire rating for field cables  
- Ingress Protection (IP) rating for field devices  
- Operation of loss of main power supplies  
- UPS systems supplies on loss of main power  
- Ex Certification ensures electrical equipment is suitable for operation in hazardous areas  
- IEC EN 61508 (Functional Safety of Electronic Safety-related Systems)  
- Energy Institute Model Code of Safe Practice Part 14 (Inspection and Testing of Protective Instrumentation) | | | | | | |
5. PERFORMANCE STANDARDS

Control SCE Barrier Table

<table>
<thead>
<tr>
<th>SCE Example (e.g. Logic Solvers and Outputs)</th>
<th>Functions</th>
<th>Reliability</th>
<th>Availability</th>
<th>Survivability</th>
<th>Interdependence</th>
<th>Example Associated Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Integrity Pressure Protection Systems</td>
<td>- Logic solver e.g. fire gas detection and control systems for pressure protection</td>
<td>- Safety integrity level (SIL) to be identified (test intervals to ensure SILs are achieved)</td>
<td>- High availability target required for overall ESD system availability (SILX/X)</td>
<td>- Provision of control functions and status indication within Temporary Refuge</td>
<td>- Fire &amp; Gas Detection criteria for overall ESD system (SILX/X)</td>
<td>- API 600 (Modular and Flexible Instrumentation)</td>
</tr>
</tbody>
</table>

Pressure Relief, Flare and Blowdown Systems
- System overpressure limits
- Relief valve specification
- Flare{l system purge (in case of system failure)
- Blowdown rate (pressure vs. time)
- Safety integrity level (SIL) to be identified (test intervals to ensure SILs are achieved) | - High availability target required for overall Blowdown system availability (SILX/X) | - Fire Safety of Reliefs, Blowdown valves and actuators | - Fire & Gas Detection criteria for Blowdown system (SILX/X) | - API RP 521 (Blowdown Prevention Systems for Drilling Wells) | - ISO 10497 (Testing of Valves - Fire Type Testing Requirements) |

Ventilation and HVAC
- HVAC air change rates (type areas, line separations)
- Location of intakes/exhausts (relative to haz. areas)
- HVAC fan and damper status indication (start & stop)
- Operation of instrumentation to monitor area pressurisation / flow rates
- HVAC damper operation, closure time and position indication | - Availability of Temporary Refuge HVAC system to match TR Impairment Frequency (TRIF) | - TR boundary dampers to have sufficient fire rating to transient to maintain endurance | - Fire & Gas detection controls fans and dampers. Isolates non-certified electrical equipment on loss of pressurisation | - API 600 (Modular and Flexible Instrumentation) |

Drilling Well Control (BOP, Mud and Cement)
- BOP closure time
- Condition/External interlock, damper support
- Capacity of BOP accumulate system (number of operations)
- Location and reliability of control points
| - BOP system to be available at all times when drilling | - Fire & Gas detection controls fans and dampers. Isolates non-certified electrical equipment on loss of pressurisation | - API 600 (Modular and Flexible Instrumentation) |

Fire Protection
- Mechanical strength/mass/geometry
- Integrity (fire resistance, fatigue, coating breakdown), mechanical damage, water ingress to insulation, security of supports etc.
- Segregation (e.g. self-sealed systems)
- Bundled areas untechnical and clear of debris | - availability of Temporary Refuge HVAC system to match TR Impairment Frequency (TRIF) | - TR boundary dampers to have sufficient fire rating to maintain endurance | - API 600 (Modular and Flexible Instrumentation) |

Marine Inert Gas Systems
- Safety integrity level (SIL) to be identified for inert gas system (test intervals to ensure SILs are achieved) | - Inert Gas system supplied during offshore operations | - Marine Inert Gas Systems Design and Installation Guide (API) |

Dynamic Positioning/Heating Control System
- Maximum excursion
- Monitoring and alarms (alarm positions, offstation, warning, warning time etc.)
- Manual and automatic operation of thrusters
- Operation and condition of thrusters
- Condition of hydraulic supplies to thrusters
- Position/heading reference data (gyro compass/GPS etc.)
| - Safety integrity level (SIL) to be identified for system (test intervals to ensure SILs are achieved) | - Emergency power supplies ensure system availability following loss of main power supplies | - Marine Inert Gas Systems Design and Installation Guide (API) |

Ignition Prevention
- Selection and condition of SCE certified electrical equipment
- Safety, condition and continuity of anti-static devices, grounding and bonding
- Location and condition of insulation in limit surface temperatures
- Condition and security of spark and flame arrestors | - Safety integrity level (SIL) to be identified for system (test intervals to ensure SILs are achieved) | - Emergency power supplies ensure system availability following loss of main power supplies | - Marine Inert Gas Systems Design and Installation Guide (API) |

Step Change in Safety - Assurance & Verification Guidance Document
## Mitigation SCE Barrier table

<table>
<thead>
<tr>
<th>SCE Example</th>
<th>Functions</th>
<th>Reliability</th>
<th>Availability</th>
<th>Survivability</th>
<th>Interdependency</th>
<th>Example Associated Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fire Water Pumps</strong></td>
<td>- Methods and operation of manual and automatic initiators</td>
<td>- Sufficient water supply to meet demand scenario identified in fire risk analysis</td>
<td>- Sufficient water supply to meet demand scenario identified in fire risk analysis</td>
<td>- Water supply to fire pumps during start-up required to ensure sufficient water supply during start-up</td>
<td>- Equipment to supply fire pumps during start-up required to ensure sufficient water supply during start-up</td>
<td>- NFA20 (Standard for the Installation of Stationary Pumps for Fire Protection)</td>
</tr>
<tr>
<td></td>
<td>- Operation of firepump starting systems (electric, mechanical, pneumatic etc.)</td>
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<td></td>
<td>- Remote status indication</td>
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<td></td>
<td>- Operation of firepump starting logic (duty, stand-by etc.)</td>
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<td></td>
<td>- Condition of diesel engine and ancillaries (fuel, coolant, ventilation etc.)</td>
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<td></td>
<td>- Pump delivery performance (flow rate, delivery pressure)</td>
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<tr>
<td><strong>Fire Water Distribution and Monitors</strong></td>
<td>- Condition of ring main pipework and supports</td>
<td>- Sufficient water supply to meet demand scenario identified in fire risk analysis</td>
<td>- Sufficient water supply to meet demand scenario identified in fire risk analysis</td>
<td>- Water supply to fire pumps during start-up required to ensure sufficient water supply during start-up</td>
<td>- Equipment to supply fire pumps during start-up required to ensure sufficient water supply during start-up</td>
<td>- NFA20 (Standard for the Installation of Stationary Pumps for Fire Protection)</td>
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<tr>
<td></td>
<td>- Operation of ring main isolation valves</td>
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<td></td>
<td>- Condition of monitors</td>
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<td>- Operation of monitor oscillation and locking devices</td>
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<td></td>
<td>- Monitor Spray patterns</td>
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<td>- Operation of interface with cooling water systems (actuated crossover valves)</td>
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<td></td>
<td>- Ringmain pressure monitoring (to initiate fire/pool pump)</td>
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<tr>
<td><strong>Deluge and Foam Systems</strong></td>
<td>- Operation of manual and automatic initiators</td>
<td>- Sufficient water supply to meet demand scenario identified in fire risk analysis</td>
<td>- Sufficient water supply to meet demand scenario identified in fire risk analysis</td>
<td>- Water supply to fire pumps during start-up required to ensure sufficient water supply during start-up</td>
<td>- Equipment to supply fire pumps during start-up required to ensure sufficient water supply during start-up</td>
<td>- NFA15 (Standard for Fire Spray Systems for Fire Protection)</td>
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<tr>
<td></td>
<td>- Deluge valve failure mode</td>
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<td></td>
<td>- Reaction time to water delivery</td>
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<td>- Spray pattern (horizontal/vertical)</td>
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<td></td>
<td>- Foam and fire distribution pressure (at most hydraulically remote nozzle)</td>
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<td>- Quality and uniformity of foam (concentration)</td>
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<td></td>
<td>- Condition of foam proportioning machines</td>
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<td></td>
<td>- Condition of foam storage tanks and distribution pipework</td>
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<tr>
<td><strong>Hosepack Firefighting Equipment</strong></td>
<td>- Operation of manual and automatic initiators</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- Foam extinguishing system to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- Foam extinguishing system to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- NFA11 (Standard for Low Medium and High Expansion Foam)</td>
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<td></td>
<td>- Quality of stored and produced foam (% concentration)</td>
<td>- Shelf life of foam concentrates</td>
<td>- Shelf life of foam concentrates</td>
<td>- Shelf life of foam concentrates</td>
<td>- Shelf life of foam concentrates</td>
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<td></td>
<td>- Condition of foam storage tanks and distribution pipework</td>
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<tr>
<td><strong>Passive Fire Protection Systems</strong></td>
<td>- Operation of manual and automatic initiators</td>
<td>- Safety Integrity Levels (SIL) to be assessed for fire pump starting and isolation</td>
<td>- Safety Integrity Levels (SIL) to be assessed for fire pump starting and isolation</td>
<td>- Safety Integrity Levels (SIL) to be assessed for fire pump starting and isolation</td>
<td>- Safety Integrity Levels (SIL) to be assessed for fire pump starting and isolation</td>
<td>- API Publication 2218 (Fireproof Practices in Petroleum and Petrochemical Processing Plants)</td>
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<tr>
<td></td>
<td>- Operation of fire pump starting and control systems</td>
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<tr>
<td></td>
<td>- Certified electrical equipment and diesel engine exhaust</td>
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<td></td>
<td>- Equipment to supply fire pumps during start-up required to ensure</td>
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<td>- Equipment to supply fire pumps during start-up required to ensure</td>
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<td></td>
<td>- Loss of hydraulic supply (pool pumps required to achieve demand)</td>
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<td></td>
<td>- Remote status indication</td>
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<tr>
<td></td>
<td>- Operation of deluge valve monitors</td>
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<tr>
<td></td>
<td>- Operation of foam distribution system</td>
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<tr>
<td></td>
<td>- Operation of foam pump monitors</td>
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<tr>
<td></td>
<td>- Sufficient foam to be supplied</td>
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<tr>
<td></td>
<td>- Foam pump isolation valves</td>
<td></td>
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<tr>
<td></td>
<td>- Operation of foam pump monitors</td>
<td></td>
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<td></td>
<td>- Sufficient foam to be supplied</td>
<td></td>
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</tr>
<tr>
<td><strong>Sprinkler Systems</strong></td>
<td>- Operation of manual and automatic initiators</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- Foam extinguishing system to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- Foam extinguishing system to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- NPA22 (Standard on Carbon Dioxide Extinguishing Systems)</td>
</tr>
<tr>
<td></td>
<td>- Remote status indication</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- Foam extinguishing system to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
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<td></td>
</tr>
<tr>
<td></td>
<td>- Minimum delivery pressure and Flow rate</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- By Design: Sufficient monitors to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
<td>- Foam extinguishing system to be installed to ensure an effective application of foam to any part of the landing area irrespective of the wind strength/direction or accident location</td>
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<tr>
<td><strong>Manual Firefighting Equipment</strong></td>
<td>- Operability of Hydrants</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
<td>- API Publication 218 (Fireproof Practices in Petroleum and Petrochemical Processing Plants)</td>
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<td></td>
<td>- Condition and availability of valve couplings</td>
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<td></td>
<td>- Quantity, condition and location of hoses</td>
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<td></td>
<td>- Condition and availability of on-line pressure regulating device</td>
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<td>- Quantity and location of wheeled and portable extinguishers</td>
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<td></td>
<td>- Certification of wheeled and portable extinguishers</td>
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<tr>
<td><strong>Passive Fire Protection (FFP)</strong></td>
<td>- Protected area</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
<td>- No specific reliability target for this Safety Critical Element (SCE)</td>
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<td>- API Publication 218 (Fireproof Practices in Petroleum and Petrochemical Processing Plants)</td>
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<td></td>
<td>- Limits of degradation - bending breakdown, exposed areas, ‘cook-back’</td>
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<td>- on attachments to protected areas</td>
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<td></td>
<td>- Vent paths adjacent to blasts with unstructured</td>
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<td></td>
<td>- Remnant of FFF jets on (Area) (SDE values)</td>
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<td>- Design criteria (fire suitable rating)</td>
<td>- Design criteria (fire suitable rating)</td>
<td>- Design criteria (fire suitable rating)</td>
<td>- Design criteria (fire suitable rating)</td>
<td>- Design criteria (fire suitable rating)</td>
<td>- Primary structures that require protection</td>
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5. PERFORMANCE STANDARDS

### Emergency Response SCE Barrier Table

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<th>Reliability</th>
<th>Availability</th>
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<th>Example Associated Standards</th>
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<tr>
<td><strong>Temporary Refuge (TR)</strong></td>
<td>- Space to house POB in case of need&lt;br&gt; - Condition of boundary doors and seals&lt;br&gt; - TR leakage rate - integrity of enclosure to retain positive pressure for survival period (to be expressed in air changes per hour)&lt;br&gt; - Number of air changes during normal operations&lt;br&gt; - Pressurisation during normal operations&lt;br&gt; - Location of inlets/ducts (relative to haz. areas)&lt;br&gt; - HVAC, forced and natural ventilation of escape, refuges and storerooms&lt;br&gt; - Operation of instrumentation to monitor gas, pressure and flow rates&lt;br&gt; - HVAC damper operation, choice time and position indication</td>
<td>- High reliability target for HVAC dampers on the TR boundary (SOLAS)&lt;br&gt; - By design: target to ensure that HVAC operate in conditions that maintain HVAC operation (pressure, temperature, flow rates)&lt;br&gt; - HVAC damper operation, choice time and position indication</td>
<td>- Availability target for Emergency Refuge to reach TR impairment (FMECA)&lt;br&gt; - TR to survive all hydrocarbon oils for a period of X minutes (by design)&lt;br&gt; - TR to survive blast overpressure of X kPa (by design)&lt;br&gt; - Provision of battery-backed emergency lighting in master and control &amp; command areas (duration)</td>
<td>- Topside Structures to provide support and survivability for the TR&lt;br&gt; - HVAC systems (including provision of fire, smoke, and explosion protection)&lt;br&gt; - HVAC systems (including provision for fire, smoke, and explosion protection)&lt;br&gt; - Active fire protection systems provide emergency command and control facilities through provision of manual firewater pump start and remote release facilities for deluge and extinguishant systems within the TR&lt;br&gt; - ESD System provide emergency process control and operation initiation feature (within the TR)&lt;br&gt; - Fire &amp; Gas Detection monitors presence of fire or potentially flammable atmospheres that could impact the TR&lt;br&gt; - UPS and emergency generator provide emergency power to command and control systems within the TR&lt;br&gt; - Emergency Communications provide remote presence of personnel that need to muster and receive information to avoid panic&lt;br&gt; - Emergency Communications provide communication facilities with aircraft, shipping (including the Emergency Response &amp; Rescue Vessel) and internal rescue agencies&lt;br&gt;</td>
<td>- ISO TS 10385 (HVAC)&lt;br&gt; - HSE Offshore Information Sheet No. 1/2006&lt;br&gt; - Emergency Institute Code Part 15 Area Classification Code for Installations. Handling Flammable Fluids (PITI)</td>
<td></td>
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<tr>
<td><strong>Escape Routes</strong></td>
<td>- Dimensions&lt;br&gt; - Visibility and links for degradation of markings&lt;br&gt; - Condition of non-slip surfaces&lt;br&gt; - Obstructions on walkways and egress/entry points&lt;br&gt; - Obstructions in connection and escape embarkation areas&lt;br&gt; - Obstructions affecting access to emergency response or escape equipment&lt;br&gt; - Condition and closure of doors at pressurised access/exit&lt;br&gt; - Intensity of escape lighting&lt;br&gt; - Signage at changes of direction</td>
<td>- By design: operational target not appropriate&lt;br&gt; - Duration of escape lighting (escape routes, master and embarkation areas)&lt;br&gt; - Diversity (number of egress routes)&lt;br&gt;</td>
<td>- Blind resistance&lt;br&gt; - Pool and jet fire resistance&lt;br&gt; - Provision of battery-backed emergency lighting to mitigate effects of smoke (duration)&lt;br&gt;</td>
<td>- Topside Structures to provide adequate support and add survivability of escape routes&lt;br&gt; - Passive Fire Protection to protect escape routes from the effects of fire/explosion&lt;br&gt; - Personal Survival Equipment to provide equipment to assist personnel to escape to a place of safety&lt;br&gt; - Emergency Communications to control alert personnel of the need to muster and advise routes/areas to avoid panic</td>
<td>- ISO TS 10385 (HVAC)&lt;br&gt; - HSE Offshore Information Sheet No. 1/2006&lt;br&gt; - Emergency Institute Code Part 15 Area Classification Code for Installations. Handling Flammable Fluids (PITI)</td>
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<tr>
<td><strong>TEMPSC</strong></td>
<td>- Condition of camp hull/wall/plating, doors, and seals&lt;br&gt; - Condition and load time requirement of full-escape&lt;br&gt; - Ballast load certification&lt;br&gt; - Condition of duct and deck connections (BRT examination)&lt;br&gt; - Operation of which bridge and release mechanism&lt;br&gt; - Device rating (load or unladed)&lt;br&gt; - Engine starting (air-lower systems)&lt;br&gt; - Operation of duct and flushing&lt;br&gt; - Security and condition of hatches&lt;br&gt; - Operation of inter-vehicle lighting&lt;br&gt; - Fuel tank level and quality (water contamination)&lt;br&gt; - Status of batteries and charging systems (fixed, time battery replacement)&lt;br&gt; - Pressurisation air (charge pressure and bottle certification)&lt;br&gt; - Operation of radio communication (with LOR, Radio Room, Sounding by voice)&lt;br&gt; - Deluge system coverage&lt;br&gt; - Operation of hydraulic and &quot;on-leave&quot; release gear (maintenance prevalent to be fitted)&lt;br&gt; - Operation (self-test) of emergency location beacon (IPPS/EAT)</td>
<td>- High reliability target for launch readiness (engine starting etc.)&lt;br&gt; - High reliability target for release gear (fail to release and fail to open)&lt;br&gt; - High reliability target for start and remote release facilities for deluge and extinguishant systems within the TR&lt;br&gt; - ESD System provide emergency process control and operation initiation feature (within the TR)&lt;br&gt; - Fire &amp; Gas Detection monitors presence of fire or potentially flammable atmospheres that could impact the TR&lt;br&gt; - UPS and emergency generator provide emergency power to command and control systems within the TR&lt;br&gt; - Emergency Communications provide remote presence of personnel that need to muster and receive information to avoid panic&lt;br&gt; - Emergency Communications provide communication facilities with aircraft, shipping (including the Emergency Response &amp; Rescue Vessel) and internal rescue agencies&lt;br&gt;</td>
<td>- High reliability target for launch readiness (engine starting etc.)&lt;br&gt; - High reliability target for instrumentation&lt;br&gt; - High reliability target for HVAC dampers on the TR boundary (SOLAS)&lt;br&gt; - By design: target to ensure that HVAC operate in conditions that maintain HVAC operation (pressure, temperature, flow rates)&lt;br&gt; - HVAC damper operation, choice time and position indication</td>
<td>- Topside Structures to support bilateral design&lt;br&gt; - Emergency Communications provide an electronic location beacon and voice communication with CCR radio or VHF radio&lt;br&gt; - Ballast System prevents heel or trim angles which could prevent TEMPSC launch from floating installations&lt;br&gt; - Ballast System prevents heel or trim angles which could prevent TEMPSC launch from floating installations&lt;br&gt; - Emergency Communications provide an electronic location beacon and voice communication with CCR radio or VHF radio&lt;br&gt; - Ballast System provides a sheltered (lee) area for the TEMPSC to launch from floating installations&lt;br&gt;</td>
<td>- ISO TS 10385 (HVAC)&lt;br&gt; - HSE Offshore Information Sheet No. 1/2006&lt;br&gt; - Emergency Institute Code Part 15 Area Classification Code for Installations. Handling Flammable Fluids (PITI)</td>
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<td><strong>Personal Survival Equipment</strong></td>
<td>- Location and quantities (relative to POB)&lt;br&gt; - Cable grabbag quantities&lt;br&gt; - Inspective/Recertification date (SOLOSA Code requirement)&lt;br&gt; - Conditions and accessibility of stowage cabinets&lt;br&gt; - Design/Construction standard of equipment&lt;br&gt; - Capacity of breathing apparatus&lt;br&gt; - Tools and PPE for Emergency Response Team and Helideck crews&lt;br&gt;</td>
<td>- By design: operational target not appropriate&lt;br&gt; - Location of equipment (relative to master + other areas)&lt;br&gt; - Provision within the Temporary Refuge&lt;br&gt; - Provision for persons who cannot access the TR in MAH</td>
<td>- Location of equipment (Emergency Location beacon)&lt;br&gt; - Equipment design rating&lt;br&gt;</td>
<td>- ISO 11618-1/2008&lt;br&gt;</td>
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<tr>
<td><strong>Emergency Response and Recovery (Stand-by) Vessel</strong></td>
<td>- Location and quantities (relative to POB)&lt;br&gt; - Cable grabbag quantities&lt;br&gt; - Inspective/Recertification date (SOLOSA Code requirement)&lt;br&gt; - Conditions and accessibility of stowage cabinets&lt;br&gt; - Design/Construction standard of equipment&lt;br&gt; - Capacity of breathing apparatus&lt;br&gt; - Tools and PPE for Emergency Response Team and Helideck crews&lt;br&gt;</td>
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<tr>
<td>Emergency Communications</td>
<td>- Available alarm type (ref. PFEER Reg. 11)</td>
<td>- High Mean Time Between Failure (MTBF) required for central and field equipment</td>
<td>- By design: if systems duplicated so that no equipment part is common to all systems (including the access panels) - High availability target required for all emergency communications systems (XX.X%)</td>
<td>- Fire &amp; Gas detection system to automatically activate emergency alarms and provide manual alarm call points - UPS provides back-up power supply following loss of main power - Emergency Response and Recovery (Stand-by) Vessel provides alternative / relay communications facilities in an emergency</td>
<td>- By design: PA systems duplicated so that no equipment part is common to all systems (including the access panels) - By design: PA systems duplicated so that no equipment part is common to all systems (including the access panels)</td>
<td>- Fire &amp; Gas detection system to automatically activate emergency alarms and provide manual alarm call points - UPS provides back-up power supply following loss of main power - Emergency Response and Recovery (Stand-by) Vessel provides alternative / relay communications facilities in an emergency</td>
</tr>
<tr>
<td>Helicopter Facilities</td>
<td>- Condition of markings (perimeter line, landing circle, “H” etc.) - Condition and security (windsock, tyre blocks, inter tie down points, perimeter and landing net) - Condition of high friction surface - Area free from debris - Conditions and illumination of evacuation location signage - Availability of portable fire extinguishers - Operation of Non-Directional Beacon (NDB) - Condition of perimeter and flood lighting (including lighting, access, and ladders) - Crash box contents - Condition of refueling system (including drains, bunds and earth bonding equipment)</td>
<td>- Helideck is only considered operational if active fire protection systems are functional - Helideck protected from blast overpressure by temporary refuge (duration) - The helideck is not expected to remain usable in scenarios involving the generation of large amounts of smoke or high levels of thermal radiation - Environmental criteria (adverse weather policy) - Emergency beacons prevent landing during emergency (event escalation)</td>
<td>- Helideck - Firefighting equipment to mitigate the effects of helicopter collision - Topples Structures provide support to helideck - Fire &amp; Gas Detection initiate on-site, righting beacons in the event of an emergency onboard the installation - Drains collect and remove vapours or other liquids from the helideck - Helideck protected from blast overpressure by temporary refuge (duration) - The helideck is not expected to remain usable in scenarios involving the generation of large amounts of smoke or high levels of thermal radiation - Environmental criteria (adverse weather policy) - Emergency beacons prevent landing during emergency (event escalation)</td>
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<td>- CAP 437 (CAA - Offshore Helicopter Landing Areas - Guidance on Standards) - HS2 Offshore Helideck Design Guidelines</td>
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<td>Emergency Response and Rescue Vessel (ERRV)</td>
<td>- Vessel capacity (100% POB = helicopter crew and full passenger complement) - Vessel specification (Superior Class) - Control of operations (helicopter ops, over-side working, adverse weather policy, man overboard drills etc.) - See Rescue Capability (Laughter and fast rescue craft, semi-rigid and manoeuvrable rescue net (Dacon Scoop), scramble nets etc.) - Medical facilities - Radar monitoring of safety zone - Communications facilities - Romney and rescue capabilities (time to rescue survivors in the event of falling overboard, helicopter ditching, escape from installation etc.)</td>
<td>- ERRV to be on location at all times and be positioned, such that it can both achieve Performance Standard - Vessel to remain within the designated patrol area at all times, including exceptional weather conditions - ERRV Master to ensure that the OIM can then direct any contingency arrangements required</td>
<td>- Helideck - Firefighting equipment to mitigate the effects of helicopter collision - Topples Structures provide support to helideck - Fire &amp; Gas Detection initiate on-site, righting beacons in the event of an emergency onboard the installation - Drains collect and remove vapours or other liquids from the helideck - Helideck protected from blast overpressure by temporary refuge (duration) - The helideck is not expected to remain usable in scenarios involving the generation of large amounts of smoke or high levels of thermal radiation - Environmental criteria (adverse weather policy) - Emergency beacons prevent landing during emergency (event escalation)</td>
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<td>- Oil &amp; Gas UK Emergency Response and Rescue Vessel Management Guidelines - O2 &amp; Gas UK Emergency Response and Rescue Vessel Survey Guidelines - HS2 Offshore Technology Report OTO 03B (Review of Probable Survival Times for Immersion on the North Sea)</td>
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6. ASSURANCE AND INTEGRITY MANAGEMENT

Introduction

The purpose of Assurance and Integrity Management is to demonstrate that the required level of Availability and Reliability of plant, equipment and systems is achieved in order for them to perform their required functions when required to do so. This includes the definition of essential requirements of SCE Management Systems (including performance metrics and data quality standards), to allow measurement, management, monitoring, and analysis of maintenance data to enable the optimisation of maintenance.

Furthermore, the OSCR requires that the Duty Holder ensures that an installation, at all times, “possesses such integrity as is reasonably practicable”.

Good business practice and Legislation drives Duty Holders to ensure assets have in place documented, robust Assurance Management processes to ensure the safe operation of the asset throughout its operational lifecycle, taking into account equipment obsolescence, natural deterioration and the effects of ageing.

Assurance Process

The Assurance processes to achieve safe and effective operations normally encompass a cyclic form of continuous improvement which is well documented with the HSE’s guidance document HSG 65, Successful health and safety management.

This is often referred to as a PLAN / DO / CHECK / ACT approach which forms the framework for a widely recognised Integrity Management System. More detail on this process can be found in the Step Change Asset Integrity Toolkit but forms the framework of the remaining guidance in this section.

Integrity Management Systems

Assurance of Management of MAH

To effectively assure the management of risks from Major Accident Hazards (MAH), the Duty Holder needs to define a clear process for the MAH and SCE’s identified (and described in earlier sections of this document).
6. ASSURANCE AND INTEGRITY MANAGEMENT

Document an inventory of existing plant and equipment with safety or business criticality.

Identifying / understanding the degradation and failure mechanisms for specified equipment, materials and designs.

Consider obsolescence of equipment.

Specify and apply appropriate maintenance activities and frequencies to deal with expected degradation to assure reliable performance.

Specify and apply appropriate inspection and testing regimes to provide early detection of impaired performance and to assure maintenance activities are achieving their intent.

Implement a robust deferral and deviation processes.

Carry out defined assurance activities and Record results

Carry out corrective measures for degraded performance and/or temporary mitigating measures

Assess occurrences of degraded performance

Monitor integrity compliance through suitable management reports and KPIs, eg SCE backlog

Consider knowledge gained through this process and implement changes where necessary to;
• effectiveness of defined assurance routines
• effectiveness of performance standard criteria
• design of equipment or plant

Assurance applies to all plant and equipment on an installation, and proactive strategies should be employed to avoid critical unplanned failures, particularly during the operational phase, which can lead to business interruption and accidents. The following example outlines one process plant system and illustrates the challenges which may be faced in an organisation where Assurance and Integrity Management is not effective.

A produced water line has been assessed as production and safety critical due to potential for oil and gas carry-over into the line and a need to assure that it will reliably retain fluids over the intended lifetime and avoid any unplanned hazardous discharges. External and internal corrosion of the line is predicted from a risk assessment, with the latter considered to be the dominant failure mechanism. Periodic wall thickness checks are carried out in defined locations to ensure maintained integrity and to monitor and record the actual condition. A trend of wall thickness reduction is observed over time and a predicted line replacement date is set. After a further period of time, areas in the line with branches of stagnant produced water (dead legs) are monitored and found to have rapid localised corrosion. These are eliminated by removal and re-design. The knowledge gained is used to review other piping systems for similar problems and any remediation necessary.
6. ASSURANCE AND INTEGRITY MANAGEMENT

As further time progresses, some areas show higher levels of loss of wall thickness than the general trend. A review is carried out to establish what action to take. According to the remaining business needs of the process system, it is established whether the piping system must be replaced entirely, partial replacement using new piping spools, or local permanent repair patches or clamps are installed. A new inspection plan is developed to monitor the revised arrangements based on the condition and expected degradation and risks.

A good Assurance process proactively addresses degradation to ensure that plant and equipment condition is known at all times through its operational life and appropriate actions are taken in advance of failures. This is well stated in the HSE’s Research Report RR509 (Plant Ageing: Management of equipment containing hazardous fluids or pressure) as: “Ageing is not about how old your equipment is; it’s about what you know about its condition, and how that’s changing over time”

Key Aspects to Consider when Planning Assurance Strategies

An assurance or maintenance strategy should be result-oriented with a ‘product’ of improved equipment reliability, productivity and asset preservation, delivered through Maintenance Services in co-operation with Production. The desired results should be defined along with measurements of target improvement in areas such as:

- Preserve technical integrity
- Increase production and operating efficiency
- Minimise scheduled downtime and unscheduled downtime
- Lower unit operating costs
- Optimise maintenance costs and eliminate waste

The strategy should define critical spares requirements and the key maintenance support contract services. Supply chain processes which support the asset maintenance management. Strategies should be reviewed on a suitable frequency to ensure that they remain aligned to the asset business objectives.

Maintenance Routines

Maintenance routines are a set of instructions to carry out specific activities on plant and equipment to ensure they continue to remain suitable and function as intended.

Maintenance routines, including inspection, are developed for all equipment and entered into the Maintenance Management System (MMS), before the equipment is brought into service and are scheduled to be implemented at specific frequencies in accordance with the maintenance strategies.

Maintenance work is selected on the basis of criticality and risk. The tools and processes applied for work selection are based on availability and reliability requirements and the complexity and lifecycle of the facility. Equipment reliability and availability requirements should be defined in the SCE Performance Standards, and the associated maintenance requirements should be scheduled with the aim of providing sufficient evidence to show compliance with these requirements.
Key Aspects to Consider when Doing Assurance

Maintenance Records

Records of activities should be readily available to demonstrate compliance with asset, company and legal requirements. The MMS should form the data depository and primary source of information, history and records for all Maintenance and Reliability activities throughout the lifecycle of the Asset.

All necessary information; including expended Technician time, equipment condition, resources used, failure / damage codes and inspection records / certification is normally recorded in the MMS at the end of each day and / or after the work is completed, and this is a valuable source of information for analysis.

A formal change management system should be in place, controlling changes and updates to the MMS structure, equipment or planned maintenance activities.

SCEs and specified plant should be identified in the MMS and the status of maintenance work performed should be monitored and reported. SCE Performance Standard requirements should be communicated through the MMS and identified in maintenance records.

The MMS should have a standard suite of reports which provide relevant, high quality and accurate information to allow monitoring of compliance, critical to ensuring the effectiveness and efficiency of scheduling, execution and supporting activities for Maintenance and Reliability.

Procedures should be in place to manage the deferment of planned and corrective maintenance and inspections.

As Found / As Left Status

When testing a SCE, it is critical that the test is performed without assisting compliance in any manner. In this way, it can be determined whether it would have performed on demand. It is also important that the “as found” status of the equipment is reported as this will help determine the Reliability and Availability of the equipment. This information is key to ensuring the right type of maintenance / testing is in place at the correct frequency, thus increasing confidence that the SCEs will work on demand.

Additionally, it is important to record the “as left” condition, so that site personnel know the status of the SCE. This could be fully operational or still requiring remedial work. If requiring remedial work, a risk assessment should be conducted to ascertain if any mitigation measures can be implemented to continue operations until the full repair is conducted.

This information should be recorded within the MMS for future analysis / auditing.

Repairs

A procedure should be in place to address all repairs (including temporary repairs) to components / systems where failures occur. The failure should be risk-assessed to determine the impact upon the system / plant or equipment involved and its suitability to continue in operation.

The process should address the quality of repairs to plant and equipment to ensure the original design integrity or Original Equipment Manufacturer (OEM) requirements are maintained. Any deviation should be formally reviewed and approved before it is implemented.

Repairs should be approved by the appropriate Technical Authority where the system is deemed safety critical, before they are implemented.
Corrective Maintenance and Priorities

Corrective work orders should be raised within the MMS for repairs to failed plant or equipment. These should be approved, and prioritised by Production and Maintenance supervision using a systematic and consistent risk-based approach to balance operational threats, business constraints and the need for effective planning and scheduling.

Key Aspects to Consider when Checking Assurance Results

Monitoring Quality of Maintenance

Quality Assurance checks should be specified and carried out by competent personnel. All work on safety critical equipment should be managed, documented, verified complete and closed out to a suitably approved standard. Supervisors should review work orders for completeness and check and confirm the integrity and quality of the information recorded in the MMS.

Availability / Reliability Analysis

Asset-specific maintenance strategies select and define the maintenance methodology most appropriate to preserving and protecting the facility and for achieving asset lifecycle objectives for safety, technical integrity, reliability and plant availability, and for optimising the maintenance effort and costs. Regular analysis of maintenance records and plant operational data should take place to confirm maintenance strategies are delivering expected outcomes.

Management of Specialist Contractors

Specialist contractors are third parties working on behalf of the Duty Holder performing activities that directly and indirectly affect the integrity of equipment. The operational interfaces with contractors / third parties should be identified, assessed, fully understood and appropriately managed. A process should be in place to ensure third party services are evaluated to establish conformance with needs, and effective interfaces with contractor management should be in place. Third party personnel should be assessed for their competence and capability to perform the work in a manner consistent with the Duty Holder’s standards. On completion of the work activity, and before leaving the site, the contractor should provide the Asset Discipline Supervisor with a draft written report on the status of the work completed, including recommendations and required follow-on actions, and areas of concern. The Asset Discipline Supervisor should ensure that equipment / systems are safely reinstated and the appropriate records / MMS are updated with the work status and findings.

Regular meetings should be held to review the status of the maintenance, where a typical agenda could include the following:
- Review past week’s performance
- Review additional work completed
- Review outstanding work
- Review key learnings
- Validate and optimise upcoming maintenance window
- Review logistical requirements
- Review emerging work
- Review any threats to the plan.

Daily meetings should be held to review completed scheduled work for that day, new corrective work, work order data quality and work scheduled for the next day. These meetings will ensure adherence with the work schedule and control break-ins required as a result of arising operational constraints.
Cumulative Risk

The Duty Holder needs to assess the effect of cumulative risk of impairments and failures on SCEs across all areas of plant, equipment and systems to ensure that MAHs remain adequately controlled to acceptable levels.

This is an important concept and refers back to the proposal at the start of this document that MAH seldom occur as the result of a single failure. Industry best practice has developed tools in recent years which gather data from several sources from the platform systems in order to analyse the Cumulative Risk.

Audit

Audits of activities defined, performed and recorded under the assurance processes should be carried out periodically and used to drive improvement of the processes.

New corrective work orders and completed corrective and planned work orders should be reviewed for completeness and quality. Work order data quality reports can be used to improve the standard of work management and work history recorded in the MMS.

Plant Performance Management

Successful Integrity Management requires the ongoing monitoring of performance in order to generate data by which to judge the success, or otherwise, of specific strategies. Performance results need to be published and analysed, and improvement in performance can only be realistically achieved when management is properly informed about current performance.

KPIs are recommended in the next paragraph, but in the absence of KPIs there shall always be some form of reporting to senior management of Monitoring and trending of safety critical equipment performance, together with equipment failures and failure to meet the required Performance Standard, with any corrective measures taken as necessary.

Key Performance Indicators (KPIs)

Indicators of successful performance to promote integrity are an essential feature of a good Integrity Management System. Indicators can be “leading”, where they flag low performance which could lead to problems or failures ahead, or “lagging”, where they record numbers of defects or failures. It is essential to provide a clear definition of any indicator to ensure that information is both consistently reported and clearly understood.

This will vary for each Duty Holder and no attempt to provide specific definitions is made in this section.

The following are examples of indicators, however these should not be taken as a conclusive or definitive list. Also the specific definition of how these measures are defined needs to be carefully considered:

- Safety Critical Backlog
  - planned maintenance backlog manhours
  - corrective maintenance backlog manhours
  - deferred maintenance backlog manhours
  - planned inspection backlog manhours
  - deferred inspection backlog manhours
- SCE Verification findings
- Number of Inhibits and Isolations under management
- Number of and trending of impaired SCEs
- Number of Safety Critical Anomalies under management
6. ASSURANCE AND INTEGRITY MANAGEMENT

Measured results should be tracked against performance indicator targets which demonstrate progress towards achieving and maintaining acceptable levels of integrity. Tolerability levels for the degree of acceptability of performance against those indicators should also be set.

Performance indicators set and used within the governance process will be aimed at monitoring progress towards excellent business performance, ensuring that good practice is being employed and that opportunities for improvement are identified.

The leading and lagging indicators should be monitored and regularly reviewed by the asset management team and a report of status should be made to senior management periodically.

Key Aspects to Consider to ACT upon Assurance Results

Management Review
The purpose of Management Reports or KPI’s should be to allow further analysis and strategic actions to be taken on the results of the monitoring and trending of safety critical equipment performance. Opportunities for improvement should be identified and incorporated into appropriate plans or strategy updates.

Root Cause Analysis
Root Cause Analysis (RCA) techniques are used to investigate poor performance and / or failures and breakdowns. RCA outcomes should be acted upon and the improvement action implemented should be reviewed at a future date to confirm its effectiveness.

An Asset Improvement process should be in place to drive change and communicate lessons learnt across the business. This should be developed from the identification and capture of findings from maintenance data analysis, breakdown / incident root cause analysis and audits.

Measuring the Effectiveness of the Maintenance Programme

In order to effectively review the data provided by the CHECK activities above discipline specific Periodic onshore / offshore reliability meetings should be held to review plant condition and reliability and maintenance performance. Additionally, a periodic performance assessment meeting should be held with review topics, including trends from condition monitoring, work order history, work scheduling, forelog and backlog management, materials usage / history and company and regulatory compliance. A plant performance and condition report should also be developed periodically.

Regular assessments of the performance of suppliers of goods and services in the delivery of their activities in relation to operational and HSE performance should be carried out and findings fed back to suppliers.

Training / Awareness

Finally, to ensure improvements in assurance strategies can be upheld it is always recommended that the workforce should be given awareness presentations / training on Asset-specific integrity management objectives and initiatives, eg. integrity expectations, corrosion management, fabric maintenance, HC leak reduction measures, safety critical equipment maintenance, management of temporary repairs etc.
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

Introduction

The following section provides guidance and good practice on how to implement Verification. Not all parts of the following text are regulatory requirements and each Duty Holder is free to interpret Regulations and HSE Guidance as they see fit, however, the application of practices such as these will assist Duty Holders in improving Major Accident Hazard management and compliance with UK offshore Verification requirements.

The Legislative requirements are clearly documented in the Regulations and are referenced and explained in the section titled Offshore UK Legislation (Page 10). The HSE also provides good guidance on these Regulations which should be referenced when seeking support.

Verification Process

The purpose of the Verification Scheme is to ensure that SCEs are, and will remain, compliant with Performance Standards through each phase of an installation’s lifecycle. Implementation of the Verification Scheme provides additional confidence, independent of the Duty Holder’s Assurance process, that the parts of the installation deemed to be Safety Critical are suitable or actions necessary to support their suitability are identified.

Verification Schemes

A Verification Scheme specifies the activities, in terms of nature and frequency, which the ICP will perform to examine the SCEs. The ICP completes the specified Verification and reports the results to a specified person within the Duty Holder’s organisation. Responses to ICP Findings are recorded and held by the Duty Holder. A good Verification process will not only ensure compliance with the Legislation, but will drive real improvements to the Assurance process associated with SCEs and Specified Plant. (See examples of good Verification in Appendix 1).

Within this document, where it states “Verification Scheme” it is intended that this includes SCEs and Specified Plant as per the statement in the OSCR Guidance – Introduction – Verification (Para 53) where it states:

The 2005 OSCR combine the requirements of the Verification Scheme with that of the Written Scheme of Examination (WSE) formerly required by PFEER to create a single Scheme.

For clarity, under the OSCR Guidance, Reg. 2 Para 87 states:

Specified Plant, provided to comply with PFEER, is another component of the provisions relating to Verification Schemes.

This is why most Duty Holders now have a single Verification Scheme that includes the identified Specified Plant under the PFEER Regulations (formerly within a Written Scheme of Examination (WSE) along with the identified SCEs.

The Verification Scheme defines specific Verification activities to be performed by the ICP to confirm the initial and continued suitability of the SCEs for each phase of an installation’s lifecycle. “Initial suitability” is a commonly used term which has evolved in the industry and represents the condition and capability of an SCE following completion of design, fabrication, construction and commissioning phases. This initial and continued suitability, through the remaining phases, will be verified against the specific performance criteria given within the Performance Standard.

Schedule 7 of the OSCR outlines the “Matters to be provided for in a Verification Scheme”.

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The Duty Holder must ensure that a Verification Scheme is developed by, or in consultation with, an ICP, to contain:

- The principles for selection of the ICP. Defined criteria for the appointment of the ICP, including measures to ensure their competence and independence
- The principles for review of the Scheme
- The arrangements for communication of necessary information
- The nature and frequency of examination and testing of SCEs / Specified Plant, where:
  - “Nature” - details the SCE Verification activities to be completed by the ICP; ie Review, Examine, Inspect, Witness, Audit etc
  - “Frequency” - quantifies how much the ICP will do in terms of sample size and period that the activity re-occurs
- Arrangements for review and revision of the Scheme
- Arrangements for making and preserving records of examination and testing, findings, remedial actions recommended and remedial action performed
- Arrangements for communication of records to an appropriate level within the Duty Holder’s organisation

It is recommended that when setting the nature and frequency of examination in the Verification Scheme, the “HSE - HID Semi Permanent Circular / Enforcement / 43 / Nature And Frequency Of Verification Of Safety Critical Elements / 1st Nov 2002” is considered. The following is an extract from this document:

SCR Schedule 9 lists the matters to be provided for in a Verification Scheme - this includes the nature and frequency of examination and testing carried out for the purposes of the Scheme. Guidance paragraph 65(a) indicates that an issue for consideration by the Duty Holder is whether an Independent Competent Person (ICP) has an adequate number of suitably qualified staff.

Inspection has shown that some Verification Schemes do not provide sufficient definition of the means by which an ICP ensures SCEs are “suitable”, or that they “remain in good repair and condition”.

The most common shortfall is a failure to provide a clear indication of the nature and frequency of the Verification activity (particularly the extent of offshore testing or the proportion of maintenance records reviewed) that the verifier is expected to carry out.

Enforcement Guidance
A suitable Scheme (SCR Guidance para 63) must include a commitment by both the Duty Holder and the ICP to a defined level of activity. What level is actually appropriate will vary considerably depending on the particular criticality and number of the SCEs. For example:

- A high integrity protection system, preventing the over-pressurisation of a hydrocarbon system, may require 100% witness by the ICP
- A Fire and Gas detection system with many detectors could be covered by the witnessing of 15% of the actual testing regime. Anything less than a 10% sample size is unlikely to be statistically satisfactory
- Where Verification activity is also carried out by the review of test records and results, similar principles apply. Sample size is particularly significant in this instance when the Performance Standard of an SCE requires the ongoing check of its availability/reliability

This should apply to Operational, Project and Modification Verification Schemes. Terms such as ‘Opportunistic’ / ‘ICP discretion’ / ‘Witness or Review’ should not be in the Verification Scheme activity as they all allow for the activity to be influenced at the time dependent upon resource or budget constraints etc.

Documenting how much the ICP should do is difficult but will support compliance with the Legislation and can be achieved through specifying percentages or quantities of items and records to be verified. The Duty Holder should define these requirements within their Verification Scheme and seek ICP approval of the content.

From the guide to the OSCR (Schedule 7 Para 337) it states that there should be arrangements made to ensure that the sample taken is not repeatedly tested. The Duty Holder should therefore ensure this is covered in the Verification Scheme and audit the ICP on how this is being managed.
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

Operational Verification Activities

Typically, an Operational Verification Scheme will specify the following types of Verification activities:

<table>
<thead>
<tr>
<th>Type</th>
<th>Verification Activities (Nature)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore</td>
<td>• Witness SCE Assurance activities (eg tests / inspections / musters etc)</td>
</tr>
<tr>
<td></td>
<td>• Visually examine condition of SCEs (eg piping, vessels, hazardous area equipment etc)</td>
</tr>
<tr>
<td></td>
<td>• Audit compliance with SCE Assurance Processes (eg Control of Temporary Equipment, Management of Inhibits, Control of Lo/Lc Valves, Management of Defined Life Repairs etc), through inspection and, testing, and the review of any offshore records</td>
</tr>
<tr>
<td>Onshore - Assurance Management System</td>
<td>• Review Maintenance and Inspection records confirming they are:</td>
</tr>
<tr>
<td></td>
<td>- suitable for assuring the Performance Standard</td>
</tr>
<tr>
<td></td>
<td>- conducted at the specified frequency</td>
</tr>
<tr>
<td></td>
<td>- reported correctly stating ‘As-Found’ and ‘As-Left’ condition</td>
</tr>
<tr>
<td></td>
<td>- reporting remedial work and ensuring it has been correctly prioritised / executed</td>
</tr>
<tr>
<td></td>
<td>• Review planned maintenance deferrals Detailed Procedural Compliance Audits (typically on a less frequent basis) of specific SCE assurance management systems, eg Piping and Vessels Inspection strategy encompassing the RBI implementation, defined life repairs etc.</td>
</tr>
</tbody>
</table>

Many Duty Holder Performance Standards quote reliability / availability figures. The ICP should review how the Duty Holder assures that these figures are being met. In relation to this, the ICP should ensure that any repeated failures to operate are identified and reported.

ICP Responsibilities

The ICP has a responsibility to:
• Comment on the record of SCEs
• Draw up, or be consulted in the development of, the Verification Scheme and thereafter the periodic review
• Perform Verification activities as defined in the Verification Scheme
• Report to the Duty Holder on the suitability of SCEs detailing Examinations / Reviews performed, Findings and Remedial Actions Recommended
• Communicate any reservations on the List of SCEs or the content of the Verification Scheme to the Duty Holder

Effectively, the ICP is providing an independent view of the initial and ongoing suitability of the SCEs and PFEER specified plant to manage the risks through the means defined in the Safety Case, and translated through the Performance Standards. The Duty Holder retains accountability and responsibility for managing risk through management systems and processes, people employed and their effective function, and the plant provided and its condition.
It should be noted that the defined role of the ICP under the Safety Case Regulations applies to activities in support of establishing the physical condition of plant and does not formally encompass the associated and essential activities in support of safety through corporate company management processes and procedures, or through the company culture or active contribution through personnel performing functions. These systems and roles and their effective performance are as essential to managing safety as the condition of the plant, and are required to be addressed by the Duty Holder. The ICP should however identify errors in Assurance management processes which could compromise the objectives of the SCE, ie being effective when required. This means that the ICP must undertake sufficient activities in order to form a professional judgement whether the SCEs are likely to remain in good condition and repair and function as required until they are verified again.

Verification Scheme Process for which the Duty Holder is accountable
7. **VERIFICATION - SUPPORTING THE ASSURANCE PROCESS**

**Initial Suitability**

The previous sections have outlined what must be written in a Verification Scheme. This section is specific to Initial Suitability, ensuring that before SCEs become operational they have been subject to a suitable Verification process.

Whether a project or modification introducing new / additional SCEs is “greenfield” (all new) or “brownfield” (major upgrade or change to existing facilities), a Verification Scheme must be in place to suitably detail the Verification activities, as described previously, for the various phases as follows:

<table>
<thead>
<tr>
<th>Phase</th>
<th>Duty Holder SCE Assurance (1)</th>
<th>ICP Verification Activities (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCE Identification</td>
<td>Identify and Record SCEs being installed or impacted by the Project / Modification</td>
<td>Comment on the List of SCEs Define high level Verification Work Instruction Review and comment on Master Document Register provided by Engineering contractor.</td>
</tr>
<tr>
<td>Procurement</td>
<td>Quality Assurance Checks on equipment / materials ordered and received</td>
<td>Review / examine Procurement Orders and Goods received</td>
</tr>
<tr>
<td>Fabrication / Construction</td>
<td>QA Plans Quality Assurance Inspections / Reviews</td>
<td>Examine / witness Fabrication / Construction Review Fabrication / Construction Dossiers (Material / Welding / NDT / Testing records)</td>
</tr>
<tr>
<td>Transportation / Installation</td>
<td>Quality Assurance Inspections</td>
<td>Examine equipment Review records</td>
</tr>
<tr>
<td>Site Commissioning</td>
<td>Testing of SCEs / Specified Plant to assure compliance with Performance Standards</td>
<td>Witness testing Examine equipment against design Review records Review punch-list items Review technical deviations</td>
</tr>
<tr>
<td>Close out / Handover to Operations</td>
<td>Compile and review closeout packs Populate relevant Duty Holder databases for SCE maintenance / inspection Issue handover documentation detailing any outstanding items, including Verification activities and findings</td>
<td>Review databases for population of new equipment and suitability of assigned operational assurance activities, eg maintenance / inspection Review outstanding punch-list items and status of Verification</td>
</tr>
</tbody>
</table>
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

Notes:
1) The Duty Holder must ensure that the Performance Standards are being met by embedding them into each phase of the Assurance Process and making people accountable for compliance. This can be achieved by obtaining appropriate engineering signatures to confirm compliance to the Performance Standards at key stages.
2) The Verification Activities will be as detailed within the Duty Holder’s Verification Scheme.
3) The Duty Holder should request the Engineering Contractor to provide a list of the documents (Master Document Register, MDR) that will demonstrate compliance of each impacted SCE against the applicable Performance Standard criteria. This approach raises awareness with the Engineering Contractor of their duty of cooperation that the Duty Holder can demonstrate compliance to their Performance Standards. This approach also provides the ICP with higher confidence that SCEs are being suitably managed.

One method of fulfilling the legislative requirements is to have, within the Verification Scheme, Initial Suitability Verification activities for each SCE that can be applied to any Project or Modification. In doing so, the activities are written in advance and can be fine-tuned depending upon the Project / Modification.

As per the Operational Verification Scheme, the “frequency” that quantifies how much the ICP has to do should be based on the criticality of the SCE, eg detailed design reviews for critical items such as risers, fabrication examinations during construction of key components, witnessing of critical commissioning tests like ESD and blowdown etc.

As the ICP gains confidence in the Assurance process, the “frequency” (eg sample size) may be reduced as determined by the Verification Scheme. For example, if several deluges were being installed by the same Engineering Contractor in the same period of time, there may be an opportunity to conduct the full Verification scope on the first deluge set and if the Assurance process was found to be working well, the ICP may only need to witness the remaining deluges. Any changes to sample size should be agreed between the Duty Holder and ICP. It should be emphasised that this practice is appropriate for the project phase but care should be taken in applying such measures in the operational phase.

The Duty Holder should determine the right time for the ICP to review documentation to ensure they do not become part of the Assurance process. In turn, it is important that the ICP is involved early enough to ensure that selected solutions will meet Performance Standards once fully developed and avoid the need for substantial re-work at a later stage.
## Operational Verification Activities

Typically, an Operational Verification Scheme will specify the following types of Verification activities:

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<tr>
<th>Type</th>
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| Offshore   | • Witness SCE Assurance activities (eg tests / inspections / musters etc)  
• Visually examine condition of SCEs (eg piping, vessels, hazardous area equipment etc)  
• Audit compliance with SCE Assurance Processes (eg Control of Temporary Equipment, Management of Inhibits, Control of Lo/Lc Valves, Management of Defined Life Repairs etc), through inspection and testing, and the review of any offshore records |
| Onshore    | • Review Maintenance and Inspection records confirming they are:  
  - suitable for assuring the Performance Standard  
  - conducted at the specified frequency  
  - reported correctly stating ‘As-Found’ and ‘As-Left’ condition  
  - reporting remedial work and ensuring it has been correctly prioritised / executed  
• Review planned maintenance deferrals  
• Detailed Procedural Compliance Audits (typically on a less frequent basis) of specific SCE assurance management systems, eg Piping and Vessels Inspection strategy encompassing the RBI implementation, defined life repairs etc. KP3 Style audits can be used as a basis for these types of audits |

Many Duty Holder Performance Standards quote reliability / availability figures. The ICP should review how the Duty Holder assures that these figures are being met. In relation to this, the ICP should ensure that any repeated failures to operate are identified and reported.
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

Management of Verification

The expectations of Verification should be defined and clearly communicated to both onshore and offshore personnel. This can be achieved through corporate policy / Verification Scheme / Job Descriptions / Verification procedures / presentations etc.

Senior management should support the Verification process as it is a useful measure of the status of their SCEs. They can support the process by:

- Ensuring Verification is completed (Projects / Modifications / Operational) through appropriate resourcing within Duty Holder and ICP’s organisation / tracking Verification completion / Managing responses to ICP Findings / Attending Duty Holder and ICP interface meetings
- Setting Corporate Verification KPIs, eg Completion of Verification Annual Workscope / Reduction in overdue ICP Findings etc

Duty Holders should detail how they manage Verification. This is typically done through a procedure or in the Verification Scheme and would normally be integrated into the Duty Holder’s Safety Management System.

The process of how to manage Verification (Operations / Modifications / Projects) should define requirements for:

- Planning:
  - Ensure effective interface between ICP and planning departments
  - Ensure good communications prior to execution of Verification activities with relevant personnel making them aware of the proposed Verification Scope
- Reporting of Verification Activities
- Reporting of Verification Findings (Refer to Findings Management below)
- Clear lines of communication between the ICP / Duty Holder and Engineering Contractor where appropriate. (an organisation chart may be beneficial here to identify key positions)
- Review and Revision of the Verification Scheme
- Roles and responsibilities. It is useful to include an organisational chart defining reporting routes for Verification
- Describe how both the arrangements for well examination and the Verification Scheme capture all wells and well-related equipment
- Verification roles and responsibilities should be defined within personnel job descriptions (for offshore and onshore personnel) if Verification is their primary role and personnel should be made aware of their roles in the delivery of Verification

ICP Responsibilities

The ICP has a responsibility to:

- Comment on the record of SCEs
- Draw up, or be consulted in the development of, the Verification Scheme and thereafter the periodic review
- Perform Verification activities as defined in the Verification Scheme
- Report to the Duty Holder on the suitability of SCEs detailing Examinations / Reviews performed, Findings and Remedial Actions Recommended
- Communicate any reservations on the List of SCEs or the content of the Verification Scheme to the Duty Holder

Effectively, the ICP is providing an independent view of the initial and ongoing suitability of the SCEs and PFEER specified plant to manage the risks through the means defined in the Safety Case, and translated through the Performance Standards. The Duty Holder retains accountability and responsibility for managing risk through management systems and processes, people employed and their effective function, and the plant provided and its condition.
It should be noted that the defined role of the ICP under the Safety Case Regulations applies to activities in support of establishing the physical condition of plant and does not formally encompass the associated and essential activities in support of safety through corporate company management processes and procedures, or through the company culture or active contribution through personnel performing functions. These systems and roles and their effective performance are as essential to managing safety as the condition of the plant, and are required to be addressed by the Duty Holder. The ICP should however identify errors in Assurance management processes which could compromise the objectives of the SCE, ie being effective when required. This means that the ICP must undertake sufficient activities in order to form a professional judgement whether the SCEs are likely to remain in good condition and repair and function as required until they are verified again.

**Duty Holder Responsibilities (directly related to Verification)**

The Duty Holder must:

- Define criteria for the appointment of the ICP
- Periodically review the competence and independence of persons executing Verification activities
- Provide adequate resources to facilitate the management of Verification including the necessary financial provisions. This is partially achieved by having clear nature and frequency defined within the Verification Scheme in order that suitable ICP resources can be resourced to execute the workscope
- Periodically audit the Verification Scheme as part of the overall Safety Management System (SMS)
- Ensure that a periodic review of the Verification Scheme is completed by, or in consultation with, an ICP and, where necessary, revise or replace it. This should consider the evolving phases of the lifecycle, material changes and thorough reviews of the Safety Case, and the impact of ageing where a more thorough review may take place
- Ensure that a note is made of any reservations made by the ICP on the record of SCEs or on the Scheme. It is a requirement that the ICP will review and agree the list of SCEs and Specified Plant. The list should be formally issued by the Duty Holder and all responses should be logged. Additionally, there should be a record of the ICP review of the Verification Scheme
- Ensure that the Scheme is put into effect
- Notify the ICP in the event of major repairs and breakdowns of SCEs
- It is recommended that regular meetings are held between the ICP and the Duty Holder to get an understanding of the status of activities completed so far, and the status of SCE compliance with Performance Standards
- A correspondence file should be kept by both the Duty Holder and ICP
- Manage Interfaces between two or more ICPs: Where more than one ICP is appointed by the Duty Holder, arrangements should be in place to manage interfaces, in terms of responsibilities, communications and Verification scope, to ensure that the process is effective with no gaps

**Additional Activities by Duty Holder to assist verification process**

- Ensure ICP Access to the Duty Holder’s Assurance Management System, Safety Management System and to the records of any specialist companies which the Duty Holder is using to manage their SCEs. It is recommended that the ICP holds a controlled copy of the Verification Scheme distributed through a formal transmittal process.
- ICP Training: Assurance Management System Training should be provided to the ICP by the Duty Holder to give the ICPs an understanding of the Duty Holder’s assurance process and ability to efficiently access records.
- Setting of KPI’s - Contracts can benefit from KPIs provided they are fair, measurable and do not drive influence or impact on the independence of the ICP. If managed well, they drive and maintain performance. These could be around continuity of personnel / delivery of reports / timely response to Verification findings, completion of activities within programme etc. Note this can apply to the ICP as well as the Engineering Contractors involved in Verification.
Further Verification Good Practice / Guidance

The following section specifically provides further guidance on the implementation of Verification and identifies what is considered to be current good practice within the industry.

Planning

Good planning of Verification activities is key to ensuring the scope is completed in the most efficient manner. The ICP will need good access to the asset / project plans in order to identify appropriate times for visits and even to link visits to certain key activities, eg Riser ESDV testing.

It is recommended that the ICP is on the distribution list of relevant asset / project plans. Current good practice is to ensure that Assurance Routines are specifically scheduled to match the verification activities for and ICP offshore visit; this allows offshore personnel to be ready and available and ICP should equally be expected to be have reviewed the planned activities prior to offshore visits.

It is important, particularly on Projects and Modifications, that the ICP is engaged during the planning process in order to allow assignment of suitable resources to execute the Verification workscope at the appropriate times. For Verification to be of value, it must be completed as close to the assurance taking place as possible. This means the ICP should be involved early in each phase and they should complete their activities in a timely manner to avoid raising findings after the project has moved to the next phase.

For all Verification scopes, it is recommended that the Duty Holder makes expectations clear to the ICP in terms of completing the scope. This can be achieved by setting Verification milestones, eg. Design Verification to be completed by a certain date or Annual Operational Verification scope to be fully completed by a certain date. This then provides visibility to the ICP of the expectations of the Duty Holder and ‘S’ curves can be used to monitor progress versus plan.

Reporting

Verification Progress Reporting:
The Duty Holder should monitor progress / completion of the Verification activities on a regular basis throughout the year to demonstrate progress. This allows review meetings to be held with the ICP to agree effective actions and to develop a recovery programme.

Failure to complete the planned Verification could ultimately lead to an Improvement Notice from the HSE. ICPs should also raise concerns when the Verification programme is not being completed in a timely manner.

Senior management should be kept informed using KPIs and / or progress reports.

The ICP should not credit completion of the scope of Verification unless the activity has been fully completed. Any incomplete activities for the year should be highlighted to the Duty Holder and clearly shown on the plan. It is good practice for the Duty Holder to audit the ICP on how they credit the Verification activities from their reports to show status of completion and thereby improve the clarity of what has been done.

Verification Activity Reporting:
The ICP report should contain adequate information to confirm completion of the Verification scope of work. Reporting by exception is not deemed suitable, ie both positive and negative findings should be reported.

The reports should clearly state whether the SCE examined meets the Performance Standard. Through the process of Verification activities, where the ICP notes deficiencies within the Performances Standards or Verification Scheme these should be formally raised to the Duty Holder. This process should be documented within the Verification Scheme / procedure.
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

For Findings raised by the ICP, the Duty Holder should aim to identify and remedy the root cause in order to avoid reoccurrence and to promote internal learning.

To aid the Duty Holder in achieving this goal the ICP should carry out a targeted review where he has concerns for the findings raised:
- Check for common and systemic failures by reviewing the maintenance management system and previous findings raised
- Check if the failed equipment was being suitably maintained by reviewing the appropriateness of the maintenance / inspection routines, including content and frequency

This review may identify inadequate / missing Planned Maintenance Routines (PMRs), PMR content or frequency and can support investigation of training, competency or compliance issues if the PMR was recently completed and no faults were reported etc.

This approach gives the ICP a fuller picture of the issue raised and the outcome of this review can be included within the finding with the action aimed towards driving the Duty Holder to identify the most “effective solution” which will prevent reoccurrence.

The ICP should issue the Verification reports in a timely manner. Typically, a target for issuance of reports should be agreed with the ICP, normally within 5-10 working days following completion of the visit to site would be considered reasonable. It is also good practice for an informal, and unofficial, quick report to be provided to appropriate parties when leaving the site to allow early attention to matters raised.

The completed report should be issued to the Duty Holder’s Verification Focal Point who should then manage the report control and distribution.

It is considered best practice that each Verification report should typically include the following information:
- Unique report number
- SCE examined
- Performance Standard reference.
- Unique Verification activity identifier and description
- Description of the examination activities completed
- Details of equipment / records examined
- Percentage of activities completed against the requirements of the Verification Scheme
- Documents reviewed and other relevant references
- Details of any outstanding activities; including reason for activities not being completed (statements like “due to operational reasons” should be avoided)
- Findings from the examination (eg is the Performance Standard measurable compliance criteria met); Note that photographs and drawings greatly enhance the quality of the report and should be used where possible
- Remedial Actions Recommended to the Duty Holder
- Details of personnel attending close-out meeting at site
- Name(s) of the ICP individual(s) that undertook the examination / audit
- Signature by the ICP author and reviewer

The OIM and appropriate personnel should be notified immediately if a finding is raised during offshore activities that identifies a failure of a Performance Standard.

Periodic Verification Status Reporting: It is recommended that the ICP provides a regular report / presentation to include the following:
- An overall Verification activity progress versus plan status
- Highlights of completed and planned Verification activities
- Areas of concern
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

- Status of Verification Scheme activities by SCE
- Status of outstanding actions from meetings / formal correspondence
- Any lessons learned that could be deemed as best practice from other Duty Holders

In order to demonstrate compliance with Legislation, records of activities supporting Verification shall be maintained in an auditable and retrievable manner by the Duty Holder on their premises until 6 months after the Verification Scheme has ceased to be current.

End of Year Reports: It is recommended that an annual Verification report and / or presentation (covering Operational / Projects / Modifications) is completed by the ICP within 1 month of the end of the annual cycle, where the status of Verification for the last year is communicated to the Duty Holder's senior management and interested parties.

Typically it should cover:
- Verification progress versus plan
- Verification Scheme status
- The findings and associated recommendations including categorisations
- Management of findings. The status of the findings showing open and overdue / As-found findings by SCE / trends etc
- Look ahead – Forthcoming work and areas for improvement of the Verification Process
- “As-found” suitability of SCEs
- Financial status (may be addressed in a separate report / presentation)

An End of Year presentation by the ICP to the Duty Holder’s senior management complements the end of year report and ensures awareness and an opportunity to reinforce leadership for MAH management.

Findings Management

The Duty Holder’s procedure / process for management and investigation of Verification Findings should be adequately defined. This process should cover:
- Reporting of Verification Findings. A visible and robust method of raising and closing Verification Findings is required. Database systems are good practice as they can provide visibility of issues / control responses and facilitate effective interrogation of the historical data to provide trends to assist in finding effective solutions
- ICP involvement in the close-out of Verification Findings. For each closure it should be evident if the ICP agreed with the closure or not. Where no ICP agreement can be reached on the closure of a Finding, this must be formally recorded and the Duty Holder is accountable
- Escalating Verification Findings, eg where no progress is being made and the Finding has gone past the due date or where the closure of ICP Findings cannot be resolved. The Escalation process should ensure visibility of the issue to senior management within the Duty Holder's organisation
- Letters of Concern. This is a commonly used method where the Verifier is able to raise concern regarding the management of SCEs or the Verification process
- Letters of Reservation. This term is defined in the SCR and represents the mechanism used by the ICP to formally document unresolved matters relevant to the record of SCEs or the content of the Verification Scheme
- Define who is responsible for responding to Verification Findings / Letters of Concern / Letters of Reservation within the Duty Holder’s and ICP’s organisation. Typically, Technical Authorities / Maintenance and Inspection Discipline Engineers are assigned responsibility for SCEs in their area of expertise. The ICP that raised the Finding is usually responsible for reviewing the response.

Verification Findings should be reviewed on regular basis by the Duty Holder and the ICP to update progress. It is also recommended that management responsible for Asset Integrity and appropriate operations personnel are involved in these meetings.
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

All Verification Findings should have realistic target closure dates which should be set appropriately by the ICP and Duty Holder in accordance with the severity of the Finding. It is recommended that the ICP is in agreement with these dates and any changes made to them. Good practice would be for a date to only be changed once, if they are made in timely manner, and where suitable evidence demonstrating progress towards closure has been appropriately managed to allow an agreed extension.

Verification Findings within the industry are categorised / named in many ways as per the requirements detailed within each Duty Holder Verification Scheme. However, as an industry, Verification Findings are reported to Oil & Gas UK for input into an industry KPI that tracks as an industry the level of open and overdue Verification Findings. These are categorised as:

- **Level 1**: Performance Standard satisfied, but ICP may suggest an improvement to the system or may request additional information to demonstrate compliance with a Performance Standard
- **Level 2**: Single Performance Standard failure with no immediate threat to the integrity of the installation
- **Level 3**: Fundamental SCE Assurance system failures that need senior management to remedy and / or resource, Multiple failures of a Performance Standard and / or immediate threat to the integrity of the Installation

The most up-to-date definition should be confirmed through reference to Oil & Gas UK.

**Review and Audit**

The Verification Scheme and associated key documentation should be kept under continuous review, revised as often as necessary and maintained up-to-date.

In addition to periodic reviews, a Verification Scheme review should be initiated by changes such as:
- Revision of any codes or standards referenced in the Verification Scheme
- Modifications to the installation which result in amendments to the list of SCEs or Performance Standards
- Revision to the installation Safety Case
- Changes to the installation operating parameters
- Changes to environmental conditions

Audits of the Verification management process should be carried out on a periodic basis which should include all the key Stakeholders, including members of the Leadership Team. These audits should also cover the ICP to ensure that the process remains compliant with Legislation.

Changes to the Verification Scheme need to be well managed to ensure all appropriate personnel are made aware and necessary approvals are obtained. Depending upon the content of the Verification Scheme, SCE Performance Standard owners (TAs), Discipline Engineers, Safety Engineering, Verification focal points and ICPs may need to be involved.
7. **VERIFICATION - SUPPORTING THE ASSURANCE PROCESS**

**Interface with Classification**

Classification of MOUs, FPSOs and FPUs can be used as a basis for, or in support of, Performance Standard requirements and activities to assure and verify compliance. The Classification processes provide good benefits in the maritime environment of the offshore industry but do not imply compliance with SCR and PFEER examination requirements alone, and should not be considered as a substitute or replacement for these. Classification Society rules may be quoted as a suitable reference within a Performance Standard or, where not directly quoted, it may be possible to demonstrate that they meet or exceed the requirements of the performance standard for a SCE and the evidence of meeting Class (approval letters, product certificates, etc.) can be used as a basis for assurance and Verification. Reporting of Verification activities should be completed in accordance with the requirements of the Written Scheme of Examination (WSE).

Where Classification Society rules do not meet all the requirements of Performance Standards, Classification should still be recognised as a contributor to Verification, but additional tasks will need to be completed by the ICP.

**Well Examination Interface**

The Verification Scheme has an interface with the Wells Examination Scheme.

DHSVs and Wellhead valves have been identified as safety critical and as such require their Verification through the Verification Scheme Process. However, a “Well” is defined within the Design and Construction Regulations as “...any device on it for containing the pressure in it...”. The interface should be established by the Duty Holder to ensure there are no gaps, however, a common definition is considered to be the downstream flange of the Xmas tree wing valves for producing Wells and the upstream flange in the case of injection or gas lift.

There is an overlap between the Verification Scheme – Operations and the Well Examination Scheme. Activities covered by the ICP often include the witnessing of the operation of the Xmas tree wing valves and the inspection of the Xmas tree itself. Where appropriate, this information should be reported back to the Well Examiner. The key is to ensure adequate communication between examining parties and avoid assumptions being made about responsibilities and activities.

The effects of subsea wells and tie-backs outside the 500m zone should be considered when investigating MAH scenarios. Duty Holders should consider if their subsea wells / structure / pipelines will be Safety Critical in the future to the drilling vessels when drilling operations are taking place over them. With this knowledge, the Duty Holder may opt to undertake Verification in projects and operations knowing that some equipment will fall within the 500m zone of the vessel and hence could be Safety Critical to that installation. In any case, Wells (including subsea wells) attached to an installation may be included within the Verification Scheme or may be covered by Well Examination.

**Combined Operations (COMOPS)**

Combined operations are defined as any operation involving the temporary interaction of two or more installations; this may be, for example, a drilling rig operating alongside the platform, or a flotel being bridge-linked to facilitate major works on the platform.

There are a number of interfaces during a combined operation, these interfaces can include hardware or software interfaces (eg alarms and communications, means of access, firewater system interconnections etc), which are likely to result in amendment to the record of SCEs for the respective installations.
7. VERIFICATION - SUPPORTING THE ASSURANCE PROCESS

The interfaces need to be clearly defined before the combined operations begin. It is recommended that a meeting is held between management representatives of the Duty Holders and their ICPs for each installation involved to understand and agree the SCE and Performance Standards affected, as well as the Verification activities required by the two ICPs. Verification activities for Combined Operations should be put in place prior to the COMOPS and carried out as required. Any changes to the Verification Schemes for each installation involved in the Combined Operations could be included as an appendix for the duration of the combined operations.

The installation Duty Holder’s ICP will normally carry out interface activities between the installation and the Drilling Rig / Flotel. Any Verification findings raised should be managed as per the Verification Scheme. Both Duty Holders should be notified of the outcome.

Once the Drilling Rig / Flotel / Vessel has been removed, the ICP will usually carry out Verification activities to ensure that the integrity of the Installation has returned.

Verification of Decommissioning and Abandonment

A controlled decommissioning and abandonment phase will commence following the end of the Operations phase.

The activities required for decommissioning and field abandonment by the Duty Holder must be documented and are subject to approval by the Health and Safety Executive and the DECC.

A new hazard assessment should be carried out with a revised list of SCEs required to manage those hazards. New Performance Standards and means of Assurance and Verification will be developed which are relevant for the new hazards. These may change during different periods of the Decommissioning process as hazards change and plans should be set to review and revise these in a timely manner.

The Verification Management Procedure / Scheme will require development in the run-up to Abandonment, as required by the Regulations. The Verification activities will have to be defined for each step, concentrating particularly on what SCEs are required, what they must be capable of doing, and the order that safety critical equipment is removed / switched off. Note that all SCEs must remain fit for purpose and be verified for continued suitability until the associated hazard is no longer present, eg gas detectors must remain operational until the installation becomes permanently gas free.
8. VERIFICATION - RELATIONSHIPS AND COMMUNICATION

Introduction

The publication of the HSE KP3 initiative progress report in July 2009 cited that there were still concerns with the way operators interact with their verifiers and the use that is made of the Independent Competent Persons and the full integrating of independent Verification activities into Duty Holders’ understanding of safety management systems.

A key part of trying to resolve this issue relates to the nature of the relationships between the various Stakeholders and the possible constraints that prevent closer integration. A Subgroup was established to specifically investigate the issues and constraints to closer integration of Verification within management systems.

This section sets out the findings of the Subgroup investigating the issues to closer integration of the Stakeholders associated with Verification.

Methodology

The Subgroup was made up of a range of parties associated with Verification, comprising representatives from the HSE, Duty Holders, Independent Verification Bodies, Independent Competent Persons.

A number of working sessions were held by the Subgroup to try and identify and gain a closer understanding of the issues that constrain closer integration. It was concluded that the best approach was to develop a questionnaire and launch it across the wider industry.

The aim was to gain a deeper understanding of the level of knowledge of the purpose of SCEs and the role Verification plays in their management, in particular amongst those at senior management level in organisations with production and Duty Holder responsibility.

This approach was adopted on the hypothesis that leadership from senior management is the key to closer integration of Verification. Gaining an insight into the understanding at this level would enable development of targeted recommendations that could be driven down through the various organisations to bring closer integration.

The survey was conducted online with participation being anonymous. The analysis of the responses formed the basis of the recommendations put forward in this section.
8. VERIFICATION - RELATIONSHIPS AND COMMUNICATION

Outputs from Working Group Sessions:

Potential Stakeholders are shown in Figure 6. On the right side are those with direct involvement, whilst those on the left are more indirect but whose role will be far more prevalent should the effectiveness of the safety system break down and allow a major accident to occur.

A key factor identified to impact on the effectiveness of Verification is the nature of relationships between the various Stakeholders and the possible constraints these present that may prevent closer integration. These high level constraints are shown in Figure 7.
8. VERIFICATION - RELATIONSHIPS AND COMMUNICATION

The most important of these constraints are further explained, as follows:

**Authority** – A lack of consistent understanding as to what level of authority the ICP holds within the Legislation. There was a perception that the ICP is a “policemen” for the Regulator.

**Contractual** – Although the ICP position is required under Legislation, the contractual / commercial relationships which prevail mean that challenges exist for the verifier to present potentially unpopular findings. The ability to maintain independence and be constructive with Verification findings can be perceived as “poor service” and possibly lead to loss of contract to competitors.

**Technical** – Within the boundaries of technical competence, an individual ICP is often required to be a generalist covering many disciplines rather than a specialist discipline engineer; this can lead to a belief that the ICP is not knowledgeable enough in a particular area. Independent Verification bodies (IVBs) are typically large enough to have technical specialist back-up across all disciplines. Where findings require specialist knowledge input which would assist in the quality and clarity of the report, this should be incorporated prior to issue to the Duty Holder.

**Findings**

Responses received to the survey questionnaire were analysed and the results are set out in the table below:

<table>
<thead>
<tr>
<th>Positive</th>
<th>Negative</th>
<th>Discussion</th>
</tr>
</thead>
<tbody>
<tr>
<td>There is a good understanding of the purpose of the Safety Case Regulations</td>
<td>The benefits are seen to be Regulatory compliance rather than direct business benefits of managing safety in an effective manner</td>
<td>Effectively controlling hazards and the resultant impact on business objectives is not broadly recognised</td>
</tr>
<tr>
<td>There is unanimous recognition that Verification has an important role in hazard management</td>
<td>Senior management often have no interface with ICP</td>
<td>If there was no Verification, focus on the Assurance process of hazard management would slip Verifier is part of Regulatory enforcement</td>
</tr>
<tr>
<td>Where verifier has regular meetings with DH management, this improves the focus and value</td>
<td>Without senior management understanding and buy-in, the value of Verification is always likely to be diluted</td>
<td>There is a desire to receive more value from IVBs</td>
</tr>
<tr>
<td>Broad opinion that the role of ICP could be expanded</td>
<td>Competency framework for ICPs would be required to achieve this</td>
<td>Regular change in asset ownership or personnel within Duty Holder organisation or verifier can have a negative impact on the effectiveness of major hazard management</td>
</tr>
</tbody>
</table>
Conclusions

The following conclusions were drawn:

• The key purpose of the Safety Case regime is to keep people safe from the major accident hazards that are present in the exploration and hydrocarbon production environments offshore. Whilst this is a legislative requirement, the clear benefit to the achievement of business strategy and objectives needs to be understood such that leadership and commitment from senior management is not for compliance with Regulations but for the benefit of the business and all Stakeholders. Making the connection between Regulatory compliance and delivery of business objectives could enhance the focus for business leaders
• Understanding the importance of Verification and its role in the prevention of Major Accidents by the Stakeholders is essential
• It is important that all persons within the Duty Holder organisation, from senior management to technician, have a sound understanding of the role played by Verification. Without senior management involvement the value is lost
• The nature of the Offshore Oil and Gas industry, with continuous changes in Owners, Operators, Duty Holders and personnel, means the value of Verification can easily be lost. It is essential that this is not allowed to happen by ensuring effective Management of organisational change
• Duty Holders and ICPs need to ensure there are robust mechanisms in place which describe the process and emphasise its importance. These should include standard reporting mechanisms
• Verification plays an important role in the achievement of business objectives through the assessment of the level of compliance with management of safety critical systems. Independence in Verification adds a greater level of transparency to the process and provides input to the Assurance framework that supports the governance forums of the business
• ICP reporting of findings from inspections needs to be comprehensive and justified, with due consideration of the value to the Duty Holder

Recommendations

The following recommendations were made:

• Further education is required throughout organisations on the purpose and benefits of the application of the Safety Case regime and greater clarity in the roles and responsibilities of the participants in the process. More proactive leadership by Duty Holders, complemented by promotional campaigns supported by the key Stakeholders; Operators, Duty Holders, Regulators and Verification Bodies; will help raise knowledge and awareness and remove constraints to closer integration of the role of independent Verification. This should cover all phases and include Design Houses and the people conducting the Assurance activities
• The Duty Holder interface with the ICP should be a relatively senior position within the organisation, with access to senior management
• ICPs should be encouraged to promote examples where Verification has added value and share lessons learned with other Duty Holders
• The way operators interact with their ICPs and the use that is made of their activities and findings needs to improve
• Management of organisation change shall be effectively implemented and should recognise potential impacts on effective management of MAH
“Safety Critical” Competency

Introduction

This section is intended to highlight two distinct issues identified under the terminology of Safety Critical competency; namely:

- Competency of ICPs - A lack of existing guidance on the meaning and assessment of ICP Competence
- Wider industry competence (All personnel supporting the Assurance of SCEs) - To improve understanding of Major Accident Hazard risk management and to help each person appreciate how their role in supporting the condition of SCEs actively contributes to minimising the risk and potential consequences of a Major Accident

ICP Independence and Competence

Summary of Legislative Requirements

The Offshore Installations (Safety Case) Regulations calls for ICPs to verify:
that the safety-critical elements and the specified plant (a) are or, where they remain to be provided, will be suitable; and (b) where they have been provided, remain in good repair and condition.

The Regulations define how an ICP shall be considered Independent (ref SC Reg.7) but not how a person shall be considered Competent:

**INDEPENDENCE** - SC Regulation 2(7) states:
For the purposes of paragraph (6) and Regulations 19 and 20 a person shall be regarded as independent only where -
(a) his function will not involve the consideration by him of an aspect, of a thing liable to be examined, for which he bears or has borne such responsibility as might compromise his objectivity; and
(b) he will be sufficiently independent of a management system, or of a part thereof, which bears or has borne any responsibility for an aspect of which he might consider, of a thing liable to be examined, to ensure that he will be objective in discharging his function.

**COMPETENCE** - SC Regulations Guideline Para 104 states:
In selecting competent persons to undertake examinations of safety-critical elements and specified plant under the written Scheme, Duty Holders should ensure that the person chosen has adequate levels of technical expertise and experience for the job.

An adequate examination of some equipment may require access to specialised technical knowledge. In other situations, a lesser degree of technical specialisation may be appropriate.

**PFEER** Guidance Para 191 states:
Competence is not defined in the regulation but it includes having the necessary theoretical and practical knowledge, and actual experience of the type of plant to be examined, to enable, in case of initial examinations, a judgment to be made on the suitability of the plant, to enable defects or weaknesses to be detected, and for their importance in relation to the performance required of the particular plant to be assessed.
Furthermore, the Regulations have an expectation that the Duty Holder shall be able to justify the choice of ICP. SC Regulations Guideline Para 103 states:

Duty Holders are responsible for selecting people to carry out Verification work who are appropriately independent and competent to do the work allocated to them. Duty Holders will need to be able to justify their selection and may wish to make reference to existing standards and established Schemes for the validation of organisations offering specialist services. However, Duty Holders are free to use other means of demonstrating compliance with the legal requirements.

The intent of this guideline is to suggest a framework for a consistent approach to the documented assessment of competence.

**Documented Systems of Competency Assessment**

Each ICP should have a system of documented competence with traceable means of assessment clearly stating the competence criteria and method of assessing the individual ICP. This can be documented in different ways and following provides an example of a framework for such a system.

In principle, an ICP competence scheme should contain the following elements:

- Competency criteria by engineering discipline or SCE specific
- Detailed criteria to define competence – in general a combination of technical knowledge and experience is required
- Frequency of review and assessment
- Definition of which lifecycle phase the person is considered competent for
- Increasing levels of competence may be defined

**Obligations of the Duty Holder**

Both OSCR and PFEER place an obligation on the Duty Holder to satisfy themselves of the competency of their selected ICP, where OSC Regulations Guidance Para 100 and PFEER Para 191 referred to above apply.

Duty Holders are legally responsible and should assure themselves that their selected ICPs are competent and can demonstrate the same. Duty Holders can achieve this by:

- Reviewing specified competency levels for ICPs
- Reviewing / interviewing individual ICPs prior to acceptance
- Documenting ICP acceptance
- Conducting regular competency audits of their selected ICPs
- Establishing the breadth and depth of knowledge of ICPs specific to wells and well-related equipment

The DCR place an obligation on the Well Operator to satisfy themselves of the independence and competence of the persons examining any part of the well. The Oil & Gas UK Well Life Practices Forum has produced guidelines on the Competency of Well Examiners.

Although it is not part of the regulatory requirements, it is recommended that this process of documented competence review applies equally to internal Technical Authorities, safety-critical equipment vendors, service companies and engineering contractors.
## 9. TRAINING, COMPETENCE AND ROLES AND RESPONSIBILITIES

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<tr>
<th>Name</th>
<th>Date of Assessment</th>
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<tr>
<th>Legislative Understanding</th>
<th>Technical Qualifications</th>
<th>Relevant Experience</th>
<th>Communication Skills</th>
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<tr>
<td>Mechanical</td>
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<td>Electrical &amp; Instrumentation</td>
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<td>Structural</td>
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<td>Pipelines</td>
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<td>Drilling &amp; Well Control</td>
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<td>Marine &amp; Safety</td>
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<td>Well Examination</td>
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<td>Project Manager</td>
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<tr>
<th>Relevant Technical Training Courses</th>
<th>Formal Education Qualifications</th>
<th>Experience (outlining responsibility in each area)</th>
<th>Technical and Personal Skills</th>
</tr>
</thead>
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<tr>
<td>Experience</td>
<td>Relevant Technical Training Courses</td>
<td>Application of Skills and Knowledge</td>
<td></td>
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<tr>
<td>Professional Qualifications eg C.Eng</td>
<td>Professional Qualifications, eg C.Eng</td>
<td>Continuous Professional Development</td>
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</tr>
</tbody>
</table>

Specialist areas:
- D – Design Review
- C – Newbuilding, Commissioning & Installation
- S – In-service ICP

Note that a person should be considered separately for competence in each of these areas within their chosen discipline.

### Levels of Competency

- **G - Gaining**
  - Note that a person at “Gaining” level may still be considered for particular tasks but the level of additional monitoring should be defined within the ICP quality system.
  - On the job training and technical courses form part of the technical assessment programme, therefore as a minimum a person should be considered “gaining” competence and have a base line knowledge strong enough to carry out activities with “appropriate” levels of supervision.
Wider Industry Safety Critical Competence & Awareness in the Management of Major Accident Hazards

What do we mean by SC & MAH Competence / Awareness

The OSC Regulations have clear expectations for safety critical plant and hardware through the full lifecycle. What is not specially considered is the personnel interacting with SCEs. Without a clear understanding of the intent of the Regulations, how compliance is achieved, how SCEs shall be suitable on a continuous basis and how it is important that they should operate on demand, there may be a detrimental impact or degradation on the performance of the SCE. For example:

- The Operator / Technician hits the clack valve first to ensure the deluge works first time
- The Instrument Technician calibrates gas detectors before applying the test gas
- The Engineer strokes the valve first before recording the closure time
- The Scaffolder erects the scaffold in front of deluge heads / gas detectors / escape routes / emergency exits etc without suitable risk assessments
- Project Engineers design modifications without consideration of SCE performance standards or potential impact on other SCEs
- Poor recording of maintenance history
- Poorly completed safety critical impairment assessments

Personnel may be technically competent within their own discipline but often fail to foresee that their actions may have far reaching implications in the event of a Major Accident.

How can SC / MAH Competence and Awareness be Improved

The following are intended as proposals to the industry to be adopted as means to increase competence in this safety critical aspect:

- Educational / Training Campaigns to promote understanding of:
  - SCEs as barriers to MAHs
  - Performance Standards and how they link to MAHs
  - Assurance and independent Verification processes
  - How individual actions can impact on the health of an SCE
- Detailed follow-up to promote the intent and value of the campaign, using:
  - Roll-out through Safety Committees and Representatives
  - Questionnaires to engage personnel and promote a base level of understanding
- A Specific industry-wide MAH Training Programme (similar to or an extension to MIST) with the specific intent of improving competency in this area but including some or all of the following elements:
  - Explanation of SC Regulations document hierarchy
  - Meaning of SCE, link to MAH and how PSs are created
  - Role of independent Verification within Duty Holder's responsibilities
  - Barriers concept, using examples of cumulative failures
  - Safety critical impairment risk assessments, clear examples showing correct application across interacting SCEs
- Persons with a more detailed role in safety critical health assurance should be identified for further detailed training
- Competency requirements for persons with a level of responsibility for SCEs should be defined within the particular organisation's quality system; from technician through to senior management level
10. MANAGEMENT OF CHANGE

Management of Change – Technical Modifications impacting on SCEs

Management of Change is one of the most important elements supporting major accident prevention throughout an Asset’s lifecycle. Poor identification of the hazards and risks exposed by change leads to improper change management and the potential for catastrophic incidents. An effective change management process will improve safety levels, production and product quality, Regulatory compliance, environmental performance and preserve company reputation. This requires awareness of potential risk, and the proper controls and governance to mitigate those risks.

Introduction

In any business, the process of assuring the beneficial improvement of key processes and equipment vital to efficient and safe operation is an important one. It is essential that a consistent approach is used to assure changes proposed will provide sustained benefits and will not cause consequential losses on other linked processes and equipment. For this reason, Management of Change (MOC) associated with technical modifications is normally a key process in company management systems.

Normally the major threat in relation to MOC is that a change is not recognised in the first place, followed by the failure to identify change impacts and implement appropriate actions that allow transition to the change. This is evident from examination of a number of globally reported major incidents, where investigations revealed failure to manage change as a root cause or a significant contributor.

The ability to manage change first requires recognition that a change is being made. A change is something that is different from what is already documented, presenting risk to the business requiring careful management. For this reason, active leadership of MOC is essential.

A similar process will normally also apply to organisational change which will cover the impacts of reorganisation and restructuring within companies, but this is not addressed under this section.

In the Offshore Oil and Gas industry the proximity of personnel to the extraction, processing, storage and export of hydrocarbons, with more difficulty in evacuating to safe distance, presents a relatively higher hazard to that of onshore industries. For this reason, Management of Change requires a higher level of application, control, Assurance and Verification. Verification by ICPs of modifications to SCEs is a requirement of the Safety Case Regulations.

What can go wrong with changes?

The Oil and Gas industry in the UK witnesses many incidents involving events where loss occurred as a result of a poor application of Management of Change. To illustrate the importance of having a robust process for managing change and ensuring that it is rigorously applied, the following fictitious example is outlined as a realistic event:

During the shutdown of an installation for planned maintenance, repairs and controlled modifications, an Operator decides that this is the opportunity to install a pressure gauge on a fuel gas knock-out pot to improve knowledge of conditions during operation. As the relevant vessel has already been isolated, purged of all gas and fluids and open to atmosphere for internal inspection, the individual simply raises a job card to modify an existing small bore branch on the vessel and fits a standard gauge taken from stores with a screwed fitting. The job card may have been subject to scrutiny offshore during the daily review of activities by the offshore management team and a risk assessment may have been carried out to support the apparent minor modification. Checks of the installation are completed by an inspector, but the modification is not sent through the MOC process for formal review and authorisation by the relevant Technical Authority.
10. MANAGEMENT OF CHANGE

Following start up of operations, the gauge fails and gas is released into the module. Unfortunately, there is no check valve or any form of isolation valve and there is no way to arrest the release of gas until the section isolated by process ESDVs fully exhausts to atmosphere. Fortunately, no ignition occurs as electrical equipment in the module is correctly specified, certified and maintained up-to-date. This was effectively a very serious near miss which could have led to a catastrophic event in the form of explosion, fire and escalation to other parts of the plant.

This is one simple example but it illustrates why even simple modifications need to be controlled by the application of a consistent procedure, correctly engineered and subject to review by authorised persons before commencing change.

What is the objective of a Management of Change process?

The MOC processes will normally have an objective, an example of which is provided below:

The objective of management of change should normally be to ensure that any relevant change is managed to minimise disruption to the continuing delivery of the business whilst maintaining rigorous health, safety and environmental standards, and the elimination of potential risks.

What represents a modification requiring Management of Change?

While each business may have a different definition for this, a typical definition of what constitutes a relevant change is essential, and this can take the form of the following:

Modifications meeting the following criteria will require the use of the Change Management process, although this list should not be considered exhaustive:

- Changes affecting the Functionality, Availability, Reliability or Survivability of a Safety Critical Element
- New Process facilities / equipment including Temporary Equipment and facilities
- Removing or by-passing equipment
- New chemicals
- Change of specification of equipment
- Change in engineering procedures
- Change in maintenance regime
- Cumulative effect of a multitude of small changes

The following are not Technical modifications:

- Like for like replacement of equipment
- Like for like replacement of chemicals
- Changes to operational parameters within design limits
- Routine activities covered by standard maintenance and operations procedures (eg scaffolding, inspection etc)
- Activities that are undertaken under other management controls, such as operational risk assessment

Like for like replacements should be carefully checked to ensure that this is truly the case. In some cases, the manufacturer may have modified or improved their product creating a conflict with, or an additional change to, the system within which it will be installed.
10. MANAGEMENT OF CHANGE

All major modifications, projects and brownfield changes should be subject to an MOC process to examine Design / Manufacture / Construction aspects with regard to their suitability to comply with Performance Standards, and this process should be embedded in the Projects Group.

Combined Operations of platforms and mobile units (eg rig, flotel, work barge) should include MOC assessments to establish the impact on SCEs. This should include a systematic review of:

- MAHs, SCEs, PSs, Assurance and Verification to identify what is a) new, b) altered and c) not altered; with actions to address a) and b)
- Verification and Classification issues and their impact on the above

The output should establish any changes necessary and any changes required to the existing Assurance and Verification activities required to ensure safe combined operations.

Who should be involved in the MOC process?

The process should define key personnel to be involved in the process and their responsibilities. Typically, this may consist of:

- The originator, initially anybody who wishes to make an improvement to Safety and Business Critical plant and Equipment through a modification to existing provisions, can make a proposal outlining proposed changes and the benefits to be gained
- A person may be appointed to be responsible for screening proposals and ultimately approving them following satisfactory review. They should have the authority and technical competency for sanctioning MOCs
- Technical Authorities for relevant disciplines may be called upon to assess proposals
- Facilities or Engineering department representative who will receive a sanctioned MOC and carry out detail design
- The ICP for the scrutiny of impact of changes to SCEs
- Where activities are delegated to a contractor, it is important for the Duty Holder to ensure that the change is effectively managed to comply with their MOC process and that Assurance and Verification needs are satisfied
- Some permanent and temporary well-related equipment may be included in the installation Verification Scheme or a third party supplier’s Assurance Scheme or may be covered by the arrangements for well examination. It is essential that changes to wells and well-related equipment are reviewed by persons with the requisite technical competence

What is the Process to be followed?

The size of any modification can vary substantially from a simple but critical, modification to instrumentation, all the way up to a major brownfield upgrade on an existing platform. While different levels of scrutiny will apply due to the varying risks, it is essential that a controlled process and authorisation is consistently applied.

Each Duty Holder may have processes in place but they should broadly be in line with the following basic processes:

1. IDENTIFY / INITIATE Change Request
   Outline reasons for change, define scope, explain benefits to be gained
   Screening by appointed responsible personnel to move to next stage or reject
   Define any necessary studies and assessments required for Assess phase
2. SELECT
Carry out Management of Change Risk Assessment with relevant technical personnel from operations, maintenance and design as necessary. This should include a suitable depth of review of relevant risks and identification of mitigation measures to be used. The residual risk should be established and a decision to progress or reject proposal should be formulated with a record of the risk assessment and agreed actions.

3. DEFINE Scope of work and detailed design

4. EXECUTE construction and commissioning
   Complete Management of Change close out records

5. CLOSE OUT / OPERATE
   Review the change that has occurred
   Capture Lessons Learned
   Formally record changes on company controlled documents

How do we complete Assurance and Verification of MOC?

For modifications to SCEs, it is essential that there is review by the Duty Holder, normally through the relevant Technical Authorities, and a level of Verification by the ICP to ensure that SCEs are “suitable for use” following the completion of modifications. The extent of Verification may vary according to the complexity of change and this should involve a staged process of review to ensure that modifications are correctly selected, developed and executed; it may be defined that the extent of modification is suitable that verification may be carried out upon completion (ie by workpack review) – but this needs to be agreed with ICP by the same engagement at the early stage of the change. The stage-gate approach assures an efficient and effective process and, by screening errors or omissions at an early stage, avoids rework and wasted effort and supports continued suitability of SCEs. Verification can provide measurable added value in projects by early identifying of costly errors.

Assurance and Verification of Modifications to SCEs

<table>
<thead>
<tr>
<th>IDENTIFY</th>
<th>SELECT</th>
<th>DEFINE</th>
<th>EXECUTE</th>
<th>OPERATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assurance / Verification Deliverable</td>
<td>Review by Assurance / Verification for conformance to Duty-holder</td>
<td>Review of work-pack prior to execution to ensure continued adherence to original concept, standards, etc.</td>
<td>Review and issue of release note prior to bringing equipment into service to ensure compliance with original design intent, standards, etc.</td>
<td></td>
</tr>
</tbody>
</table>

All sections of this document provide further text on recommended activities to support Management of Change and these should be referenced when reviewing change proposals.
Introduction

Temporary Equipment may introduce an additional hazard, or adversely affect existing SCEs. Identification of the hazards and risks exposed by Temporary Equipment is required to reduce the potential for major accidents. An effective Temporary Equipment procedure will improve safety levels, downtime and product quality, Regulatory compliance, environmental performance and preserve company reputation. The Duty Holder needs effective Assurance and Verification processes to ensure suitability of Safety Critical Temporary Equipment as required under the Safety Case Regulations.

What can go wrong with Temporary Equipment?

To illustrate the importance of having a robust process for managing Temporary Equipment and ensuring that it is rigorously applied, an example of a real event has been included:

A temporary flexible flowline and choke manifold suffered failure of the hose due to sand erosion. The temporary line had been routed through an open door to an adjacent module allowing flammable gases to migrate outside of the working module following hose failure. A HAZOP had been conducted but failed to note the presence of flow straightening vanes (thought to have been a contributor to the failure) which were not shown on the relevant drawings used onshore for the HAZOP.

[Issues: Documentation not maintained to current status; impairment of barriers to gas migration (open door); questionable representation on the onshore HAZOP team - would local site knowledge of, or visit to, installed facilities have identified the presence of flow straightening vanes?]
[Source HSE SPC/TECH/OSD/25]

This is one simple example but it illustrates why Temporary Equipment needs to be controlled by the application of a consistent procedure, correctly engineered and subject to review by authorised persons before and during use.

What is Safety Critical Temporary Equipment?

While each Duty Holder may have a different definition for this, a typical definition of what constitutes Safety Critical Temporary Equipment is essential, and this can take the form of the following:

The term ‘safety-critical elements’ (SCEs) is an important component of the provisions relating to Verification Schemes – see SCR regulation 2(5). Any structure, plant, equipment, system (including computer software) or component part whose failure could cause or contribute substantially to a major accident is safety critical, as is any which is intended to prevent or limit the effect of a major accident.

‘Temporary Equipment’ comprises equipment that is not a permanent part of the installation and which it is intended should be removed after a finite period of time. [Source HSE SPC/TECH/OSD/25-Version 3]
11. TEMPORARY EQUIPMENT – EQUIPMENT REQUIRED OFFSHORE FOR A SHORT PERIOD

The table below contains examples of Temporary Equipment that will likely be considered Safety Critical, their relation to a MAH, SCEs that they would directly impact and SCEs that they could potentially impact upon:

<table>
<thead>
<tr>
<th>Item</th>
<th>MAH</th>
<th>SCE (direct impact)</th>
<th>SCE (potential impact)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chiksan Piping</td>
<td>Release of Hydrocarbons</td>
<td>Hydrocarbon Containment</td>
<td>F&amp;G Detection</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Escape Routes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Firewater</td>
</tr>
<tr>
<td>Zone II Air Compressor</td>
<td>Fire or Explosion</td>
<td>Ignition Prevention</td>
<td>F&amp;G Detection</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Escape Routes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Emergency Shutdown</td>
</tr>
<tr>
<td>Slickline BOP</td>
<td>Release of Hydrocarbons</td>
<td>Hydrocarbon Containment</td>
<td>F&amp;G Detection</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>ESD – Reservoir Isolation</td>
</tr>
</tbody>
</table>

Who should be involved in the Control of Temporary Equipment?

Duty Holders should develop an Assurance process and associated procedures for the Management of Temporary Equipment. This should define key roles and responsibilities, typically including:

- Engineers calling off equipment
- Safety Engineers and Technical Authorities to assist in the identification of Safety Critical Equipment and their associated Performance Standards
- Vendors in the supply of equipment
- QA / Engineers / Inspection Companies / Warehouse and quayside personnel to assure supplied equipment meets the Specification / Performance Standard
- Platform personnel

Assurance of Temporary Equipment

Duty Holders must assure that any Temporary Equipment on their installation is “suitable”. An assessment needs to be made to identify if the equipment is “Safety Critical”. Where Temporary Equipment is identified as Safety Critical, it must meet the Duty Holder’s Performance Standards and this must be assured by the Duty Holder.

A typical process to ensure Temporary Equipment is adequately controlled may involve the following activities:

- Identification of requirement to assess the risk and specify the equipment
- Provide equipment to meet specification
- Assure equipment meets specification and Performance Standard prior to shipment. This can be achieved through inspection, testing and / or review of records
- Receive equipment offshore, check for transit damage, confirm suitability for hook-up at location and ensure controls are in place
- Ongoing Assurance of “continued suitability” while onboard and in use
Specific items to consider for the Control of Temporary Equipment

Duty Holders should define a time limit for Temporary Equipment. Any Temporary Equipment which exceeds this limit should be removed from service or alternatively, considered permanent, where it needs to go through a formal Management of Change process.

When bringing any Temporary Equipment onboard, an assessment should be made of its impact on existing SCEs, eg. will the equipment block escape routes, flame detectors, deluge nozzles etc.

Where Duty Holders have large load-outs of Temporary Equipment with multiple tie-ins to platform systems, they may opt to use their Management of Change process to control their Temporary Equipment.

For Drilling and Combined Operations, responsibility for Assurance and Verification should be agreed between all parties. This should be detailed in bridging documents that clearly define roles and responsibilities.

Verification of Temporary Equipment

The Verification process must be independent from the Assurance process previously described.

The Duty Holder’s Verification Scheme must document the ICP’s Verification activities in terms of Nature and Frequency for Safety Critical Temporary Equipment:

- **Nature** – Describes what the ICP will do. Essentially, the ICP should verify the Duty Holder’s Assurance process for the Control of Temporary Equipment. This can be done through auditing the process and may involve examination / review of documentation / witness of certain activities both onshore and offshore. When the ICP conducts their Verification, it is important that it is pro-active and therefore requires them to be involved at the beginning of the Assurance process and follow it through.

- **Frequency** – Describes how much the ICP will do. This is difficult to document but essentially the ICP should not be looking at every load-out of Temporary Equipment but they should take a representative sample and ensure they have verified the process from start to finish.

If, during the Verification activities, the ICP raises any Findings, these should be brought to the Duty Holder’s immediate attention for consideration before the Temporary Equipment is put into operation.
### 11. TEMPORARY EQUIPMENT – EQUIPMENT REQUIRED OFFSHORE FOR A SHORT PERIOD

<table>
<thead>
<tr>
<th>Step</th>
<th>Activity</th>
<th>Guidance</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Define company minimum requirements for Temporary Equipment</td>
<td>Typical aspects that need to be considered before the module is sent offshore are:</td>
<td>What are the Duty Holder’s Performance Standard requirements? What external codes or standards meet or exceed these requirements? What EC Directives does the equipment need to comply with? Advise suppliers in a timely manner of these requirements and have them agreed within contracts See also DNV Offshore Technical Guidance OTG-05 (add URL link)</td>
</tr>
<tr>
<td></td>
<td>System Footprint</td>
<td>• Deck loading</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>• Fire protection – structural and active</td>
<td></td>
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<td></td>
<td></td>
<td>• Hazardous areas created / located</td>
<td></td>
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<td></td>
<td></td>
<td>• Escape routes that will be affected</td>
<td></td>
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<tr>
<td></td>
<td>Utilities / Supplies</td>
<td>• Electrical – main and emergency</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>• Hydraulic</td>
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<td></td>
<td></td>
<td>• Pneumatic</td>
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<td></td>
<td>• Water – potable and cooling</td>
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<tr>
<td></td>
<td>Return Aspects</td>
<td>• Routing of pressure relief systems</td>
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<td></td>
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<td>• Drainage</td>
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<td></td>
<td></td>
<td>• Thermal load</td>
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<td></td>
<td></td>
<td>• Contamination of systems</td>
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<td></td>
<td></td>
<td>• Earthing</td>
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<tr>
<td></td>
<td>Safety Issues</td>
<td>• ESD interfaces or impacts</td>
<td></td>
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<td></td>
<td></td>
<td>• Additional Hot surfaces</td>
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<td></td>
<td></td>
<td>• Communications</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>• Impact to existing Escape Routes</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>• Fire &amp; Gas interfaces or impacts</td>
<td></td>
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<td></td>
<td></td>
<td>• Ventilation (blocking natural ventilation or contaminating safe area supplies)</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>• Emergency Lighting (additional requirements or impairment of existing provision)</td>
<td></td>
</tr>
</tbody>
</table>
## 11. TEMPORARY EQUIPMENT – EQUIPMENT REQUIRED OFFSHORE FOR A SHORT PERIOD

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<th>Step</th>
<th>Activity</th>
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</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Specify individual Temporary Equipment requirements</td>
<td>What is required?</td>
<td>Engage with installation personnel to ensure correct equipment is specified for the intended purpose and location it is to be used. Identify responsibility for installation, operation and maintenance of the equipment whilst onboard and its removal.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>How long is it required for?</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Where will it be used? - Is that location a Hazardous Area? Are there any deck loading issues?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Who will be responsible for the equipment while it is onboard? (Performing Authority)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Who may be affected by the equipment’s location or use? (Area Authority)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Identify interfaces with installation systems</td>
<td>Identify the testing and inspection requirements for these interfaces.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Does the equipment need to be connected to Fire &amp; Gas / ESD systems?</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>- What utilities are required?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- How are these to be connected?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Is the equipment compatible with the process it is being connected to? (Piping Specification)</td>
<td>Engage with supplier to identify any maintenance required.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Identify any maintenance or inspection requirements</td>
<td>Engage with supplier to identify any particular safety precautions to be observed.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Are there any operating or safety instructions required?</td>
<td>Engage with supplier to identify any specific operator competence or additional training required.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Is further operator training needed?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Is the equipment noisy? Do levels exceed the Duty Holder’s noise limits?</td>
<td>Identify further mitigation measures if required.</td>
</tr>
</tbody>
</table>
### 11. TEMPORARY EQUIPMENT – EQUIPMENT REQUIRED OFFSHORE FOR A SHORT PERIOD

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</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>Assess impact on the site</td>
<td>Does the equipment introduce a new Hazard?</td>
<td>Involve the right people in this assessment.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Will it put an excessive demand on existing SCEs (eg structures, deluge, UPS etc)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Will it adversely affect existing SCEs (eg obstruct deluge nozzles, fire detectors, escape routes, degrade emergency communications, restrict space in muster etc)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Is the equipment Safety Critical? What are the Performance Standard requirements?</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Finalise the exact specification of equipment to ensure it is suitable given the potential hazards identified</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Identify any additional measures or mitigation required to control the hazards while the equipment is onboard - ensure these are communicated to the Area Authority</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Review / Approve</td>
<td>Duty Holders may wish to formally review or approve the specification before equipment is mobilised</td>
<td>Particularly relevant where the equipment is specified by a client or other third party and not the Duty Holder</td>
</tr>
<tr>
<td>5</td>
<td>Procure Temporary Equipment</td>
<td>Ensure the required specification (certification, connections) is communicated to the supplier</td>
<td>It may be useful to include these requirements within contracts or bridging documents</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Duty Holder to assure that Temporary Equipment meets the Performance Standard prior to shipment.</td>
<td>Review documentation certification, EC Declarations of Conformity, maintenance records, lifting certs, NDE certs, function test reports, pressure test certs, zone rating certs, attend tests</td>
</tr>
<tr>
<td>6</td>
<td>Ship and receive on the installation</td>
<td>Inspect equipment upon receipt - confirm it matches what was requested and is in good condition</td>
<td>Review documentation certification, EC Declarations of Conformity, maintenance records etc</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Document the arrival of Temporary Equipment onboard (Register of Temporary Equipment) and log date it is due off</td>
<td>Monitor this document to ensure maximum allowable period is not exceeded</td>
</tr>
<tr>
<td>7</td>
<td>Preparations Before Use</td>
<td>Confirm there has been no damage in transit</td>
<td>Engage with SMEs as required (Mech, Elec, Inst, Tcom) etc</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Confirm all necessary maintenance / operations and safety instructions have been supplied</td>
<td></td>
</tr>
</tbody>
</table>
## 11. TEMPORARY EQUIPMENT – EQUIPMENT REQUIRED OFFSHORE FOR A SHORT PERIOD

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<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Review the Site Impact Assessments (including PUWER &amp; COSHH etc)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Review documentation and ensure any limitations, comments or controls are included in the permit</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ensure any additional mitigation measures are understood and complied with</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Implement noise control measures as required</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ensure equipment is located in the designated area</td>
<td>Refer to Weight Control procedures and Area Classification drawings</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Connect to installation utilities and protection systems - Proof test Fire &amp; Gas / ESD interfaces, leak test process connections</td>
<td>Retain documentation of any inspection / testing carried out</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Assess any other impacted SCEs and implement appropriate mitigation measures</td>
<td>Such as Escape routes or vent paths blocked, fire detection/fire protection systems impaired etc</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Operate the Temporary Equipment under PTW control</td>
<td>Maintain, inspect and operate Temporary Equipment in accordance with the defined requirements</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Remove Temporary Equipment</td>
<td>Isolate, disconnect and prepare equipment for backload</td>
<td>Consider any cleaning or decontamination that may be required</td>
</tr>
<tr>
<td></td>
<td>Reinstall permanent plant affected by Temporary Equipment to safe condition</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Remove Temporary Equipment from area</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Update the Register of Temporary Equipment</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Backload equipment to shore and return to supplier</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Examples of Verification Benefits

Example 1

1. Provide a single sentence summarising the relevant System and Issue

ICP identifies significant improvements to Duty Holder’s SCE Assurance Process.

2. Describe the problem and how Verification identified this Issue

Through a robust Operational Verification Scheme, the ICP was instructed to thoroughly scrutinise the SCE Assurance Process for all identified SCEs. Through this process, the ICP identified several areas where the SCE Assurance Process was not suitable and as a result escalated the issue by combining the individual issues and raised a high level Finding that allowed the Duty Holder to investigate and implement an Effective Solution.

Examples

Fire Fighting (Automatic and Manual) and Life Saving Apparatus Assurance Process was not suitable due to:
- Poorly defined Performance Standards
- Assurance activities did not assure against the Performance Standard
- Vendor had no visibility of Performance Standard
- Vendor Assurance records were poor and not visible in Duty Holder’s Maintenance Management System (MMS)
- Follow-up of Safety Critical Remedial work was not auditable

Hazardous Area Electrical Equipment Assurance Process was not suitable due to:
- Poor HAE Strategy
- Poorly managed inspections: Equipment not being inspected as per plan
- Variable Competency
- Exact Quantity of HAE items unknown.
- Poor recording of newly installed equipment.
- Resourcing not well managed to execute workload

Improvements made

Fire Fighting (Automatic and Manual) and Life Saving Apparatus Assurance Process:
- Performance Standards improved
- Assurance activities aligned to Performance Standards
- Assurance activities embedded in Duty Holder’s MMS.
- Communication with Vendor improved
- History of Assurance activities improved
- Remedial work clearly recorded in Duty Holder’s MMS.

Hazardous Area Electrical Equipment Assurance Process:
- New HAE Philosophy written and issued
- Duty Holder site audits implemented to assess effectiveness and competency of inspections
- Specific HAE onshore resource appointed
- Complete review and rescheduling to aid efficient inspections
- Manning levels better understood

Benefits

- HAE inspections being competently inspected in the most efficient manner, resulting in confidence of HAE Integrity
- Cost saving as retrospective campaigns to liquidate backlog avoided
- Cost saving as Integrity issues identified early and potentially resolved within normal outages, thus avoiding potential shutdowns for replacement of critical equipment
- Legal Compliance maintained
- Reputation secured

3. Explain the potential consequences which may have arisen should Verification not have identified the Issue

- HAE integrity would have been compromised and therefore the potential for ignition resulting in a Major Accident and potentially leading to fatalities would increase
- Improvement Notice from HSE
- Potential for shutdown until SCEs were compliant, resulting in loss of production
Examples of Verification Benefits

Example 2

1. Provide a single sentence summarising the relevant System and Issue

For Engineering Changes, the Duty Holder was unable to demonstrate that suitable Assurance Processes were in place to manage SCEs and their associated Performance Standards.

2. Describe the problem and how Verification identified this

Issue

Assurance Process by the Engineering Contractor (EC) did not suitably show SCEs and their associated Performance Standards had been assured. This resulted in SCEs not meeting their Performance Standards.

Through the Activities documented in the Verification Scheme for Projects and Modifications, the ICP identified several instances where SCEs were not meeting their Performance Standards. Examples were:

- Emergency Lighting designed / procured and tested for 90 min duration when Performance Standard was 120min
- HVAC designed to 6 air changes/hr when Performance Standard was 12 air changes/hr
- Electrical Cabling designed / procured and installed to incorrect fire protection rating

No Technical Deviations were raised by the EC.

ICP escalated the issue by combining the individual issues and raised a high level Finding that allowed the Duty Holder to investigate and implement an effective solution.

Improvements made

- Improvements to EC Assurance Process so that SCE Performance Standards were clearly assured at Design, Procurement, Construction, Commissioning and Handover. For example:
  1) Design Engineers signing to confirm they had met the identified SCE Performance Standards for each Modification / Project
  2) Commissioning identifying all the SCE Performance Standards up-front, and documenting which Offshore Test Procedures would assure that Performance Standard
- Process improved for ensuring the EC had current Performance Standards
- Communication with ICP improved

Benefits

- Increased confidence that SCEs will work as intended when required
- It is more cost effective to meet the Performance Standard before handover than to retrospectively engineer solutions to meet the Performance Standard
- Legal compliance maintained
- Reputation secured

3. Explain the potential consequences which may have arisen should Verification not have identified the issue.

- SCEs would not have been effective during a Major Accident resulting in an escalation of the event and potentially leading to fatalities
- Improvement Notice from HSE
- Potential for shutdown until SCEs were compliant, resulting in loss of production
Examples of Verification Benefits

Example 3

1. Provide a single sentence summarising the relevant System and Issue

ICP identifies significant fault in a SIL 3 rated Safety Critical system in which over pressure of an interfiled pipeline was possible.

2. Describe the problem and how Verification identified this

Issue

During function testing of an Interfield pipeline Over Pressure Protection System, (OPPS), it was noted by the Verifier that there was a fault with one of the pipeline pressure sensor control system cards for the OPPS. On investigation of the internal cards it was found that the analogue input card in slot 1 was indicating a fault signified by a Light Emitting Diode, (LED) “1” flashing. The card was also showing a green healthy LED as per the other cards installed in slots 2 and 3 which are for the other 2 pressure sensors. The fault state was not transmitted to either the matrix panel or Integrated Control Safety System, (ICSS), screens for operator attention, therefore for some unknown period of time the OPPS had been operating at a lower integrity, 2 out of 2, (2oo2) voting system.

If there are no methods by which to inform the Control Room Operators on the ICSS or the matrix panel then it is possible that 2 of the 3 cards may be in fault but the system would still be operating at a 2oo3 voting system. This has catastrophic potential as all 3 PTs could be showing overpressure but the Emergency Shutdown (ESD) System would only see the 1oo3 overpressure signal and no executive actions would be taken. The cards were located on a normally unmanned installation which made the ad-hoc discovery of the fault more unlikely.

Improvements made

• New cards provided by manufacturer which allow voting to be decreased to 1oo2 should there be any equipment failure, thus maintaining the integrity of the system
• Regular inspection of the lamps on the control panel in which the control cards are located. PM frequency amended to ensure more regular checks completed
• Remote alarm warning system implemented to allow the status of the cards to be monitored from the control room which is on a manned platform several kilometres away

Benefits

• Performance Standard availability and reliability remains assured and therefore legal compliance maintained
• Integrity of SIL rated system now much more robust
• Reduction in risk of overpressure situation arising undetected
• Reputation secured

3. Explain the potential consequences which may have arisen should Verification not have identified the issue.

• Overpressure situation within Interfield pipeline causing catastrophic event at unmanned platform. Multiple fatalities a possibility
• Huge environmental situation which is very hard to control due to ruptured subsea pipeline. Far reaching and large scale pollution
• Large Production loss
• Worldwide media, public scrutiny and criticism