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DRAFT - Integrity Management of Subsea Systems

Group Practice

**BP GROUP
ENGINEERING TECHNICAL PRACTICES**

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1. Scope

This engineering technical practice (ETP) provides guidance for managing the integrity of BP subsea facilities and their associated operations. The ETP is consistent with the requirements of BP's integrity management standard.

Integrity management requires input throughout the life cycle of the facilities, including appropriate planning and design during the project phase, monitoring and assessment during operation, and appropriate maintenance and intervention activities. This document addresses requirements for these three different stages. The document also provides guidance for the creation of a subsea integrity management strategy for any BP Asset. The document is directed towards operations personnel, but has application for projects

2. Normative References

Normative documents contain requirements that constitute requirements of this technical practice. The ETP library should be checked for updated (<http://etplib.bpweb.bp.com/home.jsp>).

The ETP categories of particular relevance are listed in Table 1.

Table 1 - Relevant engineering technical practices for Subsea Facilities & Associated Systems

Series	Title
GP 04	Civil & Geotechnics
GP 06	Corrosion
GP 18	Fabrication & welding
GP 32	Inspection & testing
GP 36	Materials selection
GP 43	Pipelines
GP 48	Processes & procedures
GP 62	Valves
GP 78	Subsea equipment
GN 35	Maintenance & reliability

3. Terms and Definitions

For the purposes of this GP, the following terms and definitions apply:

Operations

The use of subsea facilities for the production of oil and gas.

Intervention

Inspection, repair, maintenance or other related activities to support the operation of subsea facilities.

Permanent Facilities

Equipment located subsea for the field life, whose operation and primary function is to enable the production of oil and gas.

This may include water injection trees which are necessary for the reservoir to produce oil and gas.



Recoverable Equipment

Subsea equipment which is part of the permanent facilities but is designed to be retrievable, through intervention, during the field life.

A Subsea Control Module is recoverable because it will probably be replaced before the end of field life. The production of oil and gas is not possible without this piece of subsea equipment.

Temporary Equipment

Equipment which is used for subsea intervention on the permanent facilities.

4. Subsea System**4.1. Subsea Facility Limits**

- a. The subsea system within the scope of this GP includes the following:
 1. Subsea Xmas trees starting above the tubing head assembly including the choke valves;
 2. Subsea well jumpers and connectors;
 3. Manifold or pipeline end termination jumpers and connectors;
 4. Subsea control modules;
 5. Subsea sensors;
 6. Subsea distribution system, subsea umbilical termination assemblies, static umbilicals and flying leads
 7. The dynamic umbilical section from the topsides umbilical termination unit to the subsea umbilical termination assemblies;
 8. Subsea structures, manifolds and sleds including the structure and all valves;
 9. Pipeline end termination and pipeline end manifold branches to the first weld on the pipeline or flowline header;
 10. Topsides subsea control equipment, including master control station, hydraulic power unit, electrical power unit, power and communications unit, uninterruptible power supply, topsides termination unit or bulkhead interface panel and any other related permanent or sundry hardware necessary in the maintenance or operation of the subsea plant;
 11. Any chemical injection skid dedicated to subsea facilities; and
 12. Any specialist subsea equipment, including multiphase flowmeters, subsea pumps, sand monitors, corrosion monitors.
- b. The limits of the subsea facility, and interfaces with other facilities, should be defined in the Asset Subsea Integrity Management Strategy

Subsea facilities and their limits and interfaces can vary widely.
- c. It is important to clearly define these limits and interfaces within the Subsea Integrity Management Strategy. Typical interfaces are
 1. The wellhead xmas tree boundary is usually at the first isolation valve on the tree or at the first flanged connection off the tree or, if the Xmas Tree is to be included as a Subsea Facility component, the wellhead connector.
 2. On platform or floating production, storage & offloading facility or at an onshore terminal (interface with pressure system), the boundary is usually at the first isolation



valve or, if a pig trap is fitted, the first isolation valve off the main branch and off the pig trap.

3. On platform or floating production, storage & offloading facility or at an onshore terminal (interface with structure), the boundary is usually at the riser dead-weight support or hang-off support, riser support connection to platform member, pig trap or pipe-work support connection point to structure.

4.2. Subsea Intervention Activities

- a. The subsea intervention activities within the scope of this GP include the following:
 1. Diving;
 2. Vessel based survey and inspection;
 3. Onshore and offshore (above-water) survey and inspections of subsea systems;
 4. Remotely operated & autonomous underwater vehicle based inspection, repair or maintenance works;
 5. Other repair and maintenance works on subsea facilities, including those performed onshore and on the platform components of subsea facilities;
 6. Other (e.g. Xmas tree intervention works for repair, maintenance and inspection); and
 7. Subsea well intervention support and / or through bore activities.

4.2.1. Subsea Wells intervention

- a. The project team should consider what condition monitoring equipment is required downhole during the operations phase.
- b. The asset responsible subsea engineer should interface with the relevant asset responsible wells engineer for any subsea wells intervention or operations activity.

5. Implementation of Integrity Management

- a. Subsea integrity management shall comply with the BP Integrity Management Standard (IMS).
- b. The following sections describe the subsea specific issues according to each element of the IMS.
- c. During the project phase consideration should be given to reducing the requirement for physical inspections by evaluating and investing in the following:
 1. Condition monitoring
 2. Corrosion monitoring
 3. Leak detection
- d. The project team should ensure that the latest technology is reviewed and implemented to facilitate the most appropriate monitoring methods.
- e. Operations and project personnel should ensure that a life cycle integrity management approach is designed to maximise the benefit from the condition monitoring equipment.

5.1. Element 1 - Accountabilities

- a. The SPA IM shall appoint an individual for overall responsibility for integrity management of subsea facilities.



Typically the asset responsible subsea engineer will report to the field operations manager who is usually accountable for the subsea facilities.

- b. The responsible party should be supported by one or more identified subsea discipline engineers.
- c. The subsea discipline engineers should be responsible for all aspects of subsea integrity related to their discipline.

Typically, disciplines will include the following:

- *Pipelines, flowlines and umbilicals;*
 - *Subsea hardware, including Xmas trees, manifolds, valves and other associated equipment;*
 - *Subsea control systems;*
 - *Corrosion, erosion, materials management and*
 - *Flow assurance.*
- d. The EA is accountable for ensuring processes and systems are in place for the identification and management of engineering risk.
 - e. The EA should be supported by a subsea TA.

5.2. Element 2 - Competency

- a. The asset responsible subsea engineer should have a wide level of competency covering all areas of the subsea facilities.
- b. Each subsea discipline engineer should have a high level of competency in their area of discipline.
- c. Where contractors are used within the subsea integrity management strategy, then the contract should define the minimum competency levels for lead and discipline engineers.
- d. These competency levels should be verified as part of the assurance audits of the contractor.
- e. BP "Competency Online" may be used to define the required levels of competency.

Subsea discipline engineers are expected to demonstrate competency online Level 4 "Mastery" in their discipline. The asset responsible subsea engineer is expected to demonstrate competency online is Level 3 "Skillful Application" in the relevant disciplines. The remainder of the IM team will typically meet Level 2 "Basic Application".

Contractor lead engineers are expected to possess competency equivalent to competency online Level 4 "Mastery".

5.3. Element 3 - Hazard Evaluation & Risk Management

- a. Subsea integrity should be managed through an ongoing process of hazard evaluation and risk management, in accordance with the operating management system.
- b. Risk reduction plans should be used to support continuous risk reduction in alignment with the operating management system.

Risk based inspection principles may be used to prioritise resources and ensure acceptable levels of risk across assets by optimising the scope and extent of the inspection program. RBI is usually only used to supplement conventional inspection and integrity programs.

RBI is only applied where sufficient information is available to enable soundly based integrity decisions. Such information includes operational history, type of damage mechanisms, rate of deterioration and the current condition of equipment.

