

DEP SPECIFICATION

SELECTION OF MATERIALS FOR LIFE CYCLE PERFORMANCE (UPSTREAM FACILITIES) – EQUIPMENT

DEP 39.01.10.12-Gen.

February 2012

ECCN EAR99

DESIGN AND ENGINEERING PRACTICE

DEM1



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1. INTRODUCTION

1.1 SCOPE

This DEP specifies requirements and gives recommendations for materials for production systems from the reservoir to the export point.

This DEP does not generally include requirements/recommendations for:

- Structural steel for offshore platforms or superstructures, instrumentation or packaged equipment.
- Materials for complicated accessories, such as TRSSVs, chokes etc.

However, the instrument tubing used on instrumentation and packaged equipment is included in this DEP. If the packaged equipment contains pressurized hydrocarbon containing components, like piping and pressure vessels, this DEP shall be followed.

This DEP does not cover every contingency. It is the responsibility of the user to recognize when additional resources need to be brought to bear on a question or decision.

This DEP is not intended as a purchasing document and does not include inspection and testing requirements.

If conditions are encountered that are not adequately covered in this DEP, or if the user wishes to consider less conservative materials choices in the interest of potential cost savings, the Principal's materials and corrosion specialists shall be consulted.

This DEP contains mandatory requirements to mitigate process safety risks in accordance with Design Engineering Manual DEM 1 – Application of Technical Standards.

This is a revision of the DEP of the same number dated February 2011; see (1.5) regarding the changes.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorized by Shell GSI, the distribution of this DEP is confined to Shell companies and, where necessary, to Contractors and Manufacturers/Suppliers nominated by them. Any authorized access to DEPs does not for that reason constitute an authorization to any documents, data or information to which the DEPs may refer.

This DEP is intended for use in facilities related to exploration and production. For refineries and chemical plants, reference should be made to DEP 30.10.02.11-Gen. (which, even though it is originally intended for downstream use, contains useful information that can in many cases be applied to upstream equipment). This DEP may also be applied in other similar facilities.

When DEPs are applied, a Management of Change (MOC) process shall be implemented; this is of particular importance when existing facilities are to be modified.

If national and/or local regulations exist in which some of the requirements could be more stringent than in this DEP, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable with regards to the safety, environmental, economic and legal aspects. In all cases the Contractor shall inform the Principal of any deviation from the requirements of this DEP which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned, the objective being to obtain agreement to follow this DEP as closely as possible.

1.3 DEFINITIONS

1.3.1 General definitions

The **Contractor** is the party that carries out all or part of the design, engineering, procurement, construction, commissioning or management of a project or operation of a facility. The Principal may undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party that manufactures or supplies equipment and services to perform the duties specified by the Contractor.

The **Principal** is the party that initiates the project and ultimately pays for it. The Principal may also include an agent or consultant authorized to act for, and on behalf of, the Principal.

The word **shall** indicates a requirement.

The capitalized term SHALL [PS] indicates a process safety requirement.

The word **should** indicates a recommendation.

1.3.2 Specific definitions

Term	Definition
Delegated Technical Authority	A Delegated Technical Authority is a person who has received delegated authority to approve derogations from the Process Safety requirements from the Head of Shell P&T.
Derogation	A Derogation is an authorized variance or exemption from a Process Safety requirement, with specified conditions.
Sour service	Exposure to oilfield environments that contain H ₂ S and can cause cracking of materials by the mechanisms addressed in ISO 15156-1

1.3.3 Specific definitions

Term	Definition
ABS	Acrylonitrile Butadiene Styrene
CA	Corrosion allowance
CE	Carbon Equivalent
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CSCC	Chloride Stress Corrosion Cracking
EOR	Enhanced Oil Recovery
EPDM	Ethylene Propylene Diene Monomer
FEED	Front End Engineering Design
GRP	Glass Reinforced Plastic (Fibreglass). Also known as FRP (Fibre Reinforced Plastic) or GRE (Glass Reinforced Epoxy)
HAZ	Heat-Affected Zone
HIC	Hydrogen-Induced Cracking (also called Step-Wise Cracking, SWC)
HP/HT	High Pressure / High Temperature
HRC	Rockwell Hardness
IRHD	International Rubber Hardness Degrees
MESC	Materials and Equipment Standards and Codes
NACE	National Association of Corrosion Engineers
NAPRE	Nickel Alloy Pitting Resistance Equivalent
NAPRE_w	Nickel Alloy Pitting Resistance Equivalent for weld metal
OU	Operating Unit

Term	Definition
PASCC	Polythionic Acid Stress Corrosion Cracking
PE	Polyethylene
PIR	Polyisocyanurate Foam (sections, slabs)
PRE_N	Pitting Resistance Equivalent Number (N) = % Cr + 3.3 % Mo + 16 % N
PRE_W	Pitting Resistance Equivalent Number (W) = % Cr + 3.3 % (Mo + 0.5%W) + 16 % N
PTFE	Polytetrafluoroethylene
PUR	Polyurethane Foam (sections, slabs)
PVC	Polyvinyl Chloride
PVDF	Polyvinylidene Fluoride
PWC	Preferential Weld Corrosion
RTJ	Ring Type Joint
RTP	Reinforced Thermal Plastics
SCC	Stress Corrosion Cracking
SLC	Service Life Corrosion (total estimated wall thickness reduction of carbon steel during the service life of the equipment)
SME	Subject Mater Expert
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SSC	Sulphide Stress Cracking
TLP	Tension Leg Platform
TRSSV	Tubing-Retrievable Subsurface Safety Valve
TSA	Thermally Sprayed Aluminium
UHMW PE	Ultra High Molecular Weight Polyethylene
UNS	Unified Numbering System
WAG	Water Alternating Gas
WI	Water Injection
WPQ	Welding Procedure Qualification

1.4 CROSS-REFERENCES

Where cross-references to other parts of this DEP are made, the referenced section number is shown in brackets (). Other documents referenced by this DEP are listed in (4).

1.5 SUMMARY OF MAIN CHANGES

This DEP is a revision of the DEP of the same number dated February 2011. The only non editorial changes have been to:

- revise the requirements addressing material classes that require approval of the Principal as required under (3.1.1) and listed in (Appendix A). This requirement was previously a DEM1 requirement written as SHALL [PS] and is now changed to a "shall".
- refer to the requirements in (Appendix A) in clause 3.2.2 and clause 3.2.4.

1.6 COMMENTS ON THIS DEP

Comments on this DEP may be sent to the Administrator at standards@shell.com, using the DEP Feedback Form. The DEP Feedback Form can be found on the main page of “DEPs on the Web”, available through the Global Technical Standards web portal <http://www.shell.com/standards> and on the main page of the DEPs DVD-ROM.

1.7 DUAL UNITS

This DEP contains both the International System (SI) units, as well as the corresponding US Customary (USC) units, which are given following the SI units in brackets. When agreed by the Principal, the indicated USC values/units may be used.

2 GENERAL MATERIALS DESCRIPTIONS

2.1 GENERAL REQUIREMENTS FOR SPECIFIC MATERIAL GROUPS

2.1.1 Stainless steels

Due to stainless material's sensitivity to chloride content, the production stream phase behaviour SHALL [PS] be reviewed to identify that flashing conditions, which will concentrate fluid salinity and typically occur at system pressure drops, are not present. In the event such flashing conditions are present, a salinity of 250 g/l (expressed as NaCl) shall be assumed when selecting the stainless material.

Zinc or cadmium material, plating or coating shall be separated from stainless steel items. If hot work is performed on galvanized items situated in the vicinity of these components, they SHALL [PS] be shielded (e.g. with fire blankets) to avoid contamination. For components which are insulated, the cladding is considered to be sufficient protection.

Ferritic and martensitic stainless steels such as those of the 13Cr family are susceptible to sulphide stress cracking (SSC) and therefore their application shall be limited to very low concentration of dissolved H₂S and strict hardness limitations shall apply, as defined in DEP 30.10.02.15-Gen. and given in the tables in (3). Both the SSC, and the pitting crevice corrosion resistances are strongly influenced by the pH of the environment, as indicated in several tables in (3).

NOTE: DEP 30.10.02.15-Gen. is the Clarifications and Amendments to ISO 15156: Materials for Use in H₂S Environments in Oil and Gas Production. NACE MR0175 is identical to ISO 15156.

The low temperature toughness of these materials is also limited; the minimum temperature of operation limits in DEP 39.01.10.11-Gen. Appendix E shall be followed.

Martensitic stainless steels: The use of welding for these materials SHALL [PS] be reviewed and approved by the Principal. Only high grade S13Cr shall be considered for welding. Laser welded pipe SHALL [PS] not be specified.

Austenitic stainless steels containing less chromium, nickel and molybdenum than AISI 316, such as AISI 304, shall not be applied (Appendix A) unless the probability of CSCC is reduced by the specific local environment, and any such use shall be approved by the Principal.

Austenitic/ferritic stainless steels (duplex stainless steels) can suffer for both SCC and SSC, hence hardness requirements shall apply and strict dissolved H₂S limits shall be followed as given in the tables in (3). CSCC of 22Cr duplex can occur if the operating temperature is above 80°C (176°F) although failures in service have only been experienced above 100°C (212°F). 25 Cr super-duplex stainless steels are more resistant to CSCC but a limit of 110°C is recommended for design or risk assessments. Both 22 Cr duplex and 25 Cr super-duplex stainless steels are susceptible to CSCC at 80°C (176°F) under drop evaporation conditions, which indicates that accumulation of salt deposits should be avoided

The minimum design temperature of duplex stainless steels is -50°C (-58°F); qualification for low temperature use shall be accomplished as described in DEP 39.01.10.11-Gen.. For thicknesses above 30 mm other test requirements are necessary, see DEP 30.10.02.31-Gen.

In this DEP the term super duplex stainless steel is applied to all duplex stainless steels with 25 % Cr.

Super austenitic stainless steels (>6% Mo): To ensure corrosion resistance of welds a nickel alloy filler with increased Mo, such as alloy 625, SHALL [PS] be used.

Precipitation hardening stainless steels SHALL [PS] be approved by the Principal. See also (Appendix A). This applies in particular to the materials UNS S17400 (17-4 PH) and UNS S15500 (15-5PH), the use of which SHALL [PS] be restricted more stringently than specified in ISO 15156. The use of these materials shall not be considered for (potentially) sour environments. For all other environments, if this material is proposed for use where it is under cathodic protection, this shall be approved by the Principal.

2.1.2 Nickel alloys

UNS N07718 (Alloy 718) SHALL [PS] be specified in accordance with DEP 39.01.10.32-Gen.

Where galling resistance is required possible solutions include anti-galling compounds, electroplating, or use different materials for the two parts that come into contact, e.g. N06625 and N07725. An alternative approach is to specify a minimum difference in hardness of 25 HRB of the components.

At present there are no comprehensive international standards that cover the purchase requirements of Alloy 725 Inconel patent (UNS N07725) or Alloy 625+ (UNS N07716). These materials may suffer from similar issues to those that have been observed with Alloy 718, and as such, care shall be taken during manufacturing and heat treatment, particularly for critical or highly loaded components.

2.1.3 Glass Reinforced Plastics

The choice of fibre and resin should be selected after full consideration of the service requirements in accordance with DEP 30.10.02.13-Gen. GRP pipelines and piping shall be in accordance with DEP 31.40.10.19-Gen.

2.2 SPECIAL REQUIREMENTS

2.2.1 Use of ISO 10423 (API 6A) Material Classes

Table 3 of ISO 10423 specifies "materials classes", which makes reference to carbon and low alloy steels, stainless steel and CRAs. Some of the materials classes are designated for sour service.

The same materials are also used for subsea piping on sleds and manifolds. In this context carbon steels are typically ASTM A182 Grades F56, F60 and F65, whereas low alloy steels are UNS G41300 (AISI 4130), UNS G86300 (AISI 8630) and ASTM A182 Grade F22 materials. AISI 4130 and 8630 materials SHALL [PS] be purchased to ASTM A350, A694, or A707, depending on the application.

For the purpose of this DEP, it is assumed that in all cases where reference is made to stainless steel (in the context of 10423 materials), 13 Cr type stainless steels as described in (2.1.2) are intended. The use of such material is limited to environments containing low dissolved concentrations of H₂S, irrespective of the sour service designation. The Principal's materials and corrosion expert shall be consulted because there are no generally applicable guidelines that cover all materials, applications and manufacturers. In all cases where CRAs are addressed (in the context of ISO 10423), Alloy 625 (UNS N06625) shall be used as the default material for all wellhead and subsea hardware; deviations shall be approved by the Principal.

Since very large valve bodies cannot be produced by means of forging, castings shall be used; using ASTM A743 Grade CA6NM for the purpose of this DEP. Qualification procedure for such applications shall be approved by the Principal.

Reference to "trim" in the context of ISO 10423 applies to pressure controlling parts, i.e. seal faces, stems and mandrel hangers.

2.2.2 Welding of Alloy 625 clad and overlay equipment

UNS N06625 (Alloy 625) overlay welding is a commonly used material for certain corrosive fluids and deserves some special mention on quality control.

There is some iron dilution during the welding process, so the clad layer will not comply with a UNS N06625 (Alloy 625) analysis after deposition. For welding, DEP 30.10.60.18-Gen. shall apply. A minimum of two layers to weld overlay SHALL [PS] be used. The maximum allowed iron content due to dilution of deposited Alloy 625 by the underlying carbon or low alloy steel at 1 mm or less from the Alloy 625 surface, SHALL [PS] be 10%. Filler wires shall be selected and quality control carried out to ensure that this is achieved.

Welding procedures for ferritic/martensitic materials with austenitic consumables require close scrutiny, because a hard, brittle zone of relatively high carbon can form in the austenitic material immediately adjacent to the fusion boundary. This brittle zone is very sensitive to hydrogen embrittlement (hydrogen induced stress cracking, sulphide stress cracking) and even brittle fracture due to stress alone if the critical flaw size (as determined by means of CTOD tests) is exceeded. Direct exposure of such hard zones to sour conditions and cathodic protection SHALL [PS] be avoided. Simply fulfilling DEP 30.10.02.15-Gen. hardness requirements such as 250 HV 10 is not sufficient, because the brittle zone is so thin that it cannot be detected with the Vickers method of hardness testing.

For the above reason, hydrogen embrittlement is a serious risk when UNS N06625 (Alloy 625) overlaid materials are welded using UNS N06625 (Alloy 625) buttering. The same alloy has even been used to butter non-clad low alloy steel forgings and martensitic stainless steels.

When carrying out buttering, the closure weld shall be made with UNS N06625 (alloy 625). Maximum hardness of 325 HV 10 in the base metal and HAZ are accepted for non-sour and sour service, provided that the bore is fully clad (Ref. ISO 15156-3 clause A13.1).

2.2.3 Protection against catastrophic failure mechanisms

Catastrophic failure mechanisms such as stress corrosion cracking, (corrosion) fatigue, and low temperature embrittlement shall be prevented by means of proper materials selection and design. Coatings or corrosion inhibition SHALL [PS] not be used as barriers to stress corrosion cracking or corrosion fatigue during design.

If operating temperatures change to the extent that the chloride stress corrosion cracking temperature limit is exceeded, the use of coating or aluminium foil may be considered, but shall be subject to proper management of change and approved by the technical authority. If approved, candidate coatings should have a design life at least as long as the design life of the facilities. Conventional coatings are not acceptable.

Metals in sour services shall conform to DEP 30.10.02.15-Gen. and quality control SHALL [PS] be implemented to assure that these materials conform to the DEP's material and fabrication requirements. When assessing material suitability, the pH and H₂S partial pressure shall represent not only normal life cycle exposures but also exposures as can reasonably be expected to occur during an upset or flow condition (e.g., normal packer fluid pH versus condensing water pH after a tubing to annulus leak, or pH of flowline fluid versus condensing water pH during stratified flow).

An exception to the rule of not using coatings to protect equipment against potentially catastrophic failure is that it is considered acceptable to protect carbon and low alloy steels against Hydrogen Induced Cracking (HIC) or stepwise cracking by means of coatings, provided that the coating integrity is ensured by means of a suitable maintenance program and that a program is in place to detect and monitor HIC formation and growth. For practical purposes this only applies to vessels.

2.2.4 Protection of stainless steels with thermally sprayed aluminium

Stainless steels may be protected against external pitting and crevice corrosion by means of coating with Thermally Sprayed Aluminium (TSA). As an alternative, austenitic stainless steel may be cleaned with fresh water and, after being dried, wrapped in 100% pure aluminium foil, approximately 60 µm (2-½ mil) thick. Joints and ends SHALL [PS] be taped with self-adhesive aluminium tape. This aluminium foil acts as both a barrier coat and inhibitor. The applicable temperature range for the use of aluminum foil under insulation is 50 to 200°C (122 to 392°F) for continuous service and 50 to 480°C (122 to 896°F) for cyclic conditions.

Achieving good external TSA coverage of small-bore (<DN 50) (<NPS 2) components is extremely difficult, so selecting a resistant material is the preferred option. If the consequence of failure is low, the decision may be taken to install a low-cost susceptible material and change it out if it fails.

2.2.5 Sealing materials

Where metal-to-metal seals are used there is a potential risk of galvanic corrosion. To prevent this, the seal surface material shall be at least as noble as the surrounding surfaces. Elastomer seals are addressed in (3.2.13).

3. MATERIALS SELECTION BY EQUIPMENT SYSTEM

3.1 INTRODUCTION

3.1.1 General

This section includes materials for process and utility equipment used in onshore, offshore, and subsea operations for exploration and production.

The application of materials listed in the material classes in (Appendix A, Table A.1) shall require specific approval of the Principal. If materials standards are not specified in this DEP, or in the applicable equipment DEPs, DEP 30.10.02.11-Gen. shall be used to identify the appropriate materials standard.

If the corrosion rate is known from service experience or prediction, then the Service Life Corrosion (SLC) figure should be used for materials selection. Otherwise, basic operating condition data may be used to obtain possible materials options. For corrosive conditions not adequately described, a materials specialist should be consulted.

The SLC, which is applicable only to carbon steels, is the service life corrosion including the effects of corrosion control, if applied, and any excursions. The normal procedure is to work out the SLC without corrosion control. If this gives an acceptable SLC value no corrosion control is required. If the initial SLC figure is too high (from a technical or economic perspective), then it should be recalculated taking into account the effects of the selected corrosion control system and associated reliability or expected maintenance.

The environmental limits for production fluids, in terms of H₂S, temperature, chloride content, pH, etc., represent basic recommendations of the suitability of the material for such an environment. In some cases the actual limits of applicability of individual materials might be higher than those shown in the tables in the following sections. The limits in the tables are based on the assumption that the pH of the environment is 3.5 for gas systems, unless otherwise stated. A pH of 3.5 is selected because this is the most severe condition for production operations (e.g. gas systems with only condensed water). A pH of 4.5 is selected in some cases as the most severe for oil production systems (see DEP 39.01.10.11-Gen., clause 2.3.3.2).

NOTE: Lower pH environments occur for short periods of time during acidizing and flow back of (partially) spent acids. If not properly controlled, these conditions can lead to severe corrosion.

If the pH is expected to be higher (less acidic), some relaxation of these limits might be possible. If needed, materials might be qualified for service outside the conditions indicated in the following sections by consulting a materials and corrosion specialist.

It is emphasized that materials selection depends on multiple variables that often interact. The applicability of materials in the multi-dimensional space of such factors as temperature, pH, and chloride content and dissolved H₂S concentration is not fully defined. The tables in this section typically list discrete combinations of factors for which the materials have been qualified. Extrapolation between different combinations of factors may only be done by the Principal materials and corrosion experts, who can decide whether additional testing is required.

The Principal materials and corrosion expert should be consulted on appropriate test methods (e.g. EFC 17) and guidance on interpretation of results. Generic alloy groups or individual alloys need separate qualification addressing items such as resistance to general corrosion, sulphide stress cracking, stress corrosion cracking, pitting, crevice corrosion, and galvanic effects.

3.2 PRODUCTION SYSTEMS

3.2.1 General

This clause covers downhole and facilities/topsides equipment that handle produced fluids, oil, gas, and produced water.

The material selected for many items shall meet minimum toughness requirements at the minimum design temperature during blowdown conditions. The low-temperature limitations of materials are covered in detail by DEP 30.10.02.31-Gen., which gives approximate minimum temperatures for different materials for guidance and DEP 31.38.01.15-Gen., which refers to ASME B31.3.

3.2.2 Downhole Tubing and Liners

Detailed production tubing material selection depends upon an analysis of the flow regime, corrosivity of the well fluids, materials properties and economic factors. Table 1 gives general guidelines on suitable materials depending upon the cumulative corrosion loss anticipated for the lifetime of the well and the anticipated environmental conditions. The restrictions noted in (Appendix A) shall also apply.

For materials for water injection tubing see (3.4.1.6).

Indicative limits are given for Alloy 28 in Table 1; when using this alloy expert advice shall be sought.

Use of GRE is limited by the combination of pressure and diameter – for increasing diameter the pressure rating decreases (ref. DEP 30.10.02.13-Gen. and DEP 31.40.10.19-Gen.); pressure here should be the maximum differential pressure across the tubing / lining / casing, i.e. “internal” overpressure (weep or burst failure mode) or “external” overpressure (collapse failure mode, which is not covered in the referenced DEPs). There are limitations on wall thickness: diameter ratio that should be considered. There are also some limitations on the maximum string length in terms of load bearing capacity (ratio of strength to density). These case specific issues should be discussed with the supplier and the Principal's materials and corrosion experts.

Use of GRE lined CS should be limited to products qualified by testing or approved by the Principal. Carbon steel base material shall meet the same requirements for CS in sour service. In deviated wells, wear issues shall be assessed and other approved tubing materials shall be installed at kickoff points as needed.

The use of carbon steel shall include a site-specific assessment of SLC and the needed wall allowance during the well life. Downhole corrosion inhibition may be considered for mitigation of required SLC above the deepest injection point.

Coated tubing SHALL [PS] not be considered as a method of improving corrosion time to failure. Coated production tubing, both carbon steel and CRA, shall be considered as a mitigation of work over costs (e.g., reduced fishing), enhanced tubing reuse, and improved flow performance.

Table 1: Downhole production tubing, liners, and casing

Production	Conditions				Material
	SLC	Temp.	Sour Regions H ₂ S ⁽¹⁾	NaCl	
	mm (in)	°C (°F)	mbar (psi)	g/l	
Oil wetting of walls (Non-corrosive service)	<3 (<1/8)	<200 (<392)	Regions 0 or 1	Any	CS, ISO 11960, any strength grade.
Water contact with walls (Corrosive or sour service)	<3 (<1/8)	<200 (<392)	Regions 0 or 1	Any	CS ⁽¹³⁾ , ISO 11960, any strength grade.
	<3 (<1/8)	<200 (<392)	Regions 2 or 3	Any	CS ⁽¹³⁾ , ISO 11960 Q+T grades with hardness ≤ 250 HV 10 (≈ 22HRC) and C90 and T95 grades ⁽²⁾
	<3 (<1/8)	80-200 (176-392)	Regions 2 or 3	Any	CS ⁽¹³⁾ , ISO 11960 Grade P110 or lower strength ⁽²⁾ with Max. 140 ksi yield
	<3 (<1/8)	110-200 (230-392)	Regions 2 or 3	Any	CS ⁽¹³⁾ , ISO 11960, Grade Q-125 or lower strength.
Water contact with walls (Corrosive sweet service, i.e. "non-sour" service)	N/A	<110 (<230)	<3.5 (<0.05)	<165	13Cr
	N/A	<170 (<338)	<3.5 (<0.05)	<20	13Cr
	N/A	<140 (<284)	<3.5 (<0.05)	<165	S13Cr ⁽³⁾
	N/A	<200 (<392)	<3.5 (<0.05)	<20	S13Cr ⁽³⁾
Water contact with walls (Corrosive sour service)	N/A	As « non-sour »	<5 (<0.07)	As « non-sour »	13Cr or S13Cr ^{(3),(4)} (pH >3.5)
	N/A	<200 (<392)	<20 (<0.30)	<250	22Cr Duplex SS
	N/A	<200 (<392)	<100 (<1.45)	<250	Super Duplex
	N/A	<160 (<320)	<14,000 (<203)	<250	Alloy 825
	N/A	<200 (<392)	<36,000 (<522)	<250	Alloy 28 (pCO ₂ <25 bar)
	N/A	<160 (<320)	<14,000 (<203)	<250	Alloy 28
	N/A	<200 (<392)	<80,000 (<1160)	<250	Alloy 2550/G3
	N/A	<280 (<568)	<120,000 (<1740)	<250	Alloy C276/C22/G50
	N/A	<110 (<230)	Any	Any	GRE lined CS
Wet/dry oil/condensate	N/A	<100 (<196)	Any	Any	GRE

(see next page for NOTES)

- NOTES
- (1) SSC regions as defined in Figure 1 of ISO 15156-2. H₂S pressures refer to partial pressures of H₂S. See also ISO 15156-1.
 - (2) Where necessary, higher strength grades might be qualified for a specific application. Guidance on qualification testing can be found in ISO 15156 Part 1 or EFC 16.
 - (3) Super 13Cr are proprietary materials.
 - (4) Limited to L80 13Cr (AISI 420).
 - (5) to (12) notes no longer used
 - (13) In accordance with ISO 15156 Table A.3, Q-125 Types 1 and 2 based on Q & T, Cr-Mo chemistry to 1,036 MPa (150,259 psi) maximum yield strength. C-Mn steels are not acceptable.

3.2.3 Casing

General annulus corrosion SHALL [PS] be controlled by the use of pH adjustment and oxygen scavengers and/or biocides in the annulus fluids.

Grade selection SHALL [PS] be based on the carbon steel entries of Table 1 assuming short-term exposure to produced fluids.

3.2.4 Xmas trees

General guidelines on suitable materials for Xmas trees are given in Table 2. The restrictions noted in (Appendix A) shall also apply.

The standard recommended materials of construction of subsea Xmas tree flow loops are carbon steel clad with Alloy 625, solid super duplex stainless steel or solid AISI 410 stainless steel, within the environmental limits of these materials as specified in Table 2. Sealing surfaces SHALL [PS] in all cases be overlaid with Alloy 625 where there is a potential for crevice corrosion. See (2.2.2). Only qualified suppliers of AISI 410 SHALL [PS] be considered because welding and selection of fittings and flanges for AISI 410 requires special attention.

The "Material Requirements" guidance for wellhead and Xmas tree equipment provided by ISO 10423 in Table 3 should be used with care, because the classes are very broad. It should also be noted that ISO 10423 Table 3 defines "trim" as "pressure-controlling parts, stems and mandrel hangers". The use of Alloy 625 for trims arises from the need to prevent even minor corrosion of valve seals and sealing faces that could impair their function.

For Alloy 718 a maximum of 0.2 % proof stress should be specified. The details of the heat treatment SHALL [PS] be checked by the Principal and the heat treatment process witnessed. Where there is any doubt about the heat treatment the microstructure should be checked (replication techniques have been successfully used to quantify the amounts of delta phase). Where delta phase is detected expert opinion should be sought on defining acceptable levels. For sour exposure above 5,000 mbar (72 psi) pH₂S, laboratory evaluation of representative material in field specific conditions should be carried out.

Table 2: Xmas trees

Conditions				Material
Temp	pH ₂ S	NaCl	Other	
°C (°F)	mbar (psi)	g/l		
Any	<3.5 (<0.05)	<200	SLC <3	Carbon steel with Alloy 625 trims
<140 (<284)	<3.5 (<0.05)	<165		Martensitic stainless steel (F6NM/CA6NM) with Alloy 625 trims.
<200 (<392)	<3.5 (<0.05)	<20		Martensitic stainless steel (F6NM/CA6NM) with Alloy 625 trims.
As non- sour	<5 (<0.07)	As non- sour	pH >3.5	Martensitic stainless steel (F6NM/CA6NM) with Alloy 625 trims.
<200 (<392)	<10 (<0.15)	<250		22Cr Duplex
<200 (<392)	<20 (<0.29)	<250		25Cr Super Duplex
<200 (<392)	<80 (<1.16)	<50		25Cr Super Duplex
<200 (<392)	<5,000 (<73)	<200		Alloy 718 or Alloy 925 with Alloy 625 sealing faces ⁽⁴⁾
<240 (<392)	<30,000 (<435)	<250		Alloy 625 type, e.g., Alloy 625+, Alloy 625PH or Carbon steel clad throughout with Alloy 625 ⁽⁴⁾

NOTES: (1) - (3) notes no longer used

(4) For Alloy 625 the partial pressure of carbon dioxide has an impact on performance. For the conditions quoted here the maximum pCO₂ is 23 bar. At lower H₂S levels higher CO₂ levels can be allowed. When using this alloy in such conditions expert advice should be sought.

3.2.5 Vessels and Piping

This clause does not apply to glycol contactor and regeneration system vessels (3.2.9) and utility systems, including water systems (3.4).

Where carbon steel plus inhibition is used in upstream piping, the vessel shall have suitable internal corrosion protection, such as CRA cladding or organic coating.

CRA cladding and lining may be full or partial depending upon the assessed corrosivity. If partial lining is selected, this shall be approved by Principal.

Suitable materials for vessels as given in Table 3, depend upon the cumulative corrosion loss estimated for the SLC and other internal environment constraints. Materials for vessels shall be in accordance with requirements of either DEP 31.22.10.32-Gen., DEP 31.22.11.32-Gen. or DEP 31.22.20.31-Gen., depending on whether the vessel is designed to PD 5500, EN 13445 or ASME VIII.

In Table 3, 1420 and 1440 piping classes (see DEP 31.38.01.15-Gen.) are sour service grade carbon steel piping specifications. These materials are not intended for low temperature service.

Hardness requirements and sulphur limitations are covered in DEP 39.01.10.11-Gen.

For carbon steel in a clad vessel the recommendations are as follows:

- Follow the hardness requirements and S limitation in DEP 39.01.10.11-Gen. clause 2.4.4.4 Table 4. This gives good quality steel without excessive cost.
- No requirement for HIC testing of the steel.
- Be very certain in the design and fabrication that the cladding is continuous over the whole vessel surface.
- This approach is NOT suitable for partially clad vessels.

CRA clad vessels do not require a corrosion allowance to be applied to the carbon steel underneath the cladding.

Internal cracking of stainless steels is a risk if the chloride levels in Table 3 are exceeded. This can occur through chloride conditions higher than expected in the fluids entering the system (e.g. formation water is higher in chlorides than expected or there are high chlorides occurring from acid returns or returns of completion fluids). Internal cracking can also occur through concentration of the chlorides within the piping system. Austenitic stainless steels can also suffer from Polythionic Acid Stress Corrosion Cracking (PASCC), which can occur when these materials are in sour service and are exposed to air. More details are given in (2.1.2). The risk of cracking should be assessed when selecting stainless steel materials.

Guidance on internal coating of vessels and piping is provided in DEP 70.48.11.30-Gen.

Vessel linings (e.g. glass flake epoxy systems) shall not be selected for high corrosion rate systems or where significant erosive particles are anticipated; if the coating breaks down a failure of the carbon steel might occur before it would be detected by inspection. Where linings are used, the vessel shall be scheduled for 6 yearly internal inspections or within a period set by evaluation of potential corrosion rates, to determine the condition of the lining, and make any necessary repairs to the lining.

Galvanic anodes should be considered in conjunction with linings in vessels. Galvanic anodes may be an option if (a) vessel waters have a pH above 5.0 and temperature below 50°C (122°F), (b) a minimum of 3 mm (1/8 in) corrosion allowance is present, and (c) sufficient corrosion allowance is available for vapour phase corrosion. Either Zinc or Aluminium alloy anodes may be used. Magnesium anodes shall not be used.

Indicative limits for Alloy 28 and 625 are included in Table 3; when using these alloys expert advice shall be sought.

Table 3: Vessels and piping

Internal Environmental conditions				Materials selection for piping ⁽¹⁰⁾	Piping class ⁽¹⁾	Vessel material
SLC mm (in)	Temp °C (°F)	pH ₂ S mbar (psi)	NaCl g/l			
<1 (<1/32)	<200 (<392)	<3.5 (<0.05)	Any	CS with 1 mm (1/32 in) CA	1410, 1450, or 1470	As for piping
<3 (<1/8)	<200 (<392)	<3.5 (<0.05)	Any	CS with 3 mm (1/8 in) CA	1430 or 1490	As for piping
3 to 6 (1/8 to 1/4)	<80 (<176)	<3.5 (<0.05)	Any	CS with 3 mm (1/8 in) CA ⁽²⁾ . CS with glassflake lining if only limited life is required ⁽³⁾	1430 or 1490	As for piping + glass flake lining ⁽⁴⁾ . Temperature limit is for the glass flake lining.
<1 (<1/32)	<200 (<392)	<100 (<1.45)	Any	SSC and HIC- resistant steel with 1 mm (1/32 in) CA	1420 or 1460	As for piping
<3 (<1/8)	<200 (<392)	<100 (<1.45)	Any	SSC and HIC- resistant steel with 3 mm (1/8 in) CA	1440	As for piping
3 to 6 (1/8 to 1/4)	<80 (<176)	<100 (<1.45)	Any	SSC and HIC- resistant steel with 3 mm (1/8 in) CA ⁽²⁾ . CS with glassflake lining if only limited life is required ⁽³⁾	1440	As for piping + glass flake lining ⁽⁴⁾ . Temperature limit is for the glass flake lining.
≥6 (≥1/4)	<120 (<248)	<8 (<0.12)	100	AISI 316L	3430	CS clad with AISI 316L or solid AISI 316L ⁽⁵⁾ or 22Cr Duplex ⁽⁵⁾
≥6 (≥1/4)	<200 (<392)	<10 (<0.15)	<250	22Cr Duplex	3832	CS clad with AISI 904L or solid 22Cr Duplex ⁽⁵⁾
≥6 (≥1/4)	<60 (<140)	<15 (<0.22)	100	AISI 316L	3430	CS clad with AISI 316L or solid AISI 316L ⁽⁵⁾ or 22Cr Duplex ⁽⁵⁾
≥6 (≥1/4)	<200 (<392)	<20 (<0.30)	<250	Super Duplex		CS clad with AISI 904L or solid 22Cr Duplex ⁽⁵⁾
≥6 (≥1/4)	<200 (<392)	<80 (<1.16)	<50	Super Duplex		CS clad with AISI 904L or solid 22Cr Duplex ⁽⁵⁾
≥6 (≥1/4)	<200 (<392)	<350 (<5.08)	<1 (1000 ppm)	22Cr Duplex	3832	CS clad with AISI 316L or solid 22Cr Duplex ⁽⁵⁾ .