

DEP SPECIFICATION

**SELECTION OF MATERIALS FOR UPSTREAM
EQUIPMENT**

**(INCLUDING AMENDMENTS AND SUPPLEMENTS TO
ISO 15156:2009)**

DEP 39.01.10.12-Gen.

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DESIGN AND ENGINEERING PRACTICE

DEM1



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TABLE OF CONTENTS

PART I	INTRODUCTION	6
1.1	SCOPE	6
1.2	DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS	6
1.3	DEFINITIONS	7
1.4	CROSS-REFERENCES	9
1.5	SUMMARY OF MAIN CHANGES.....	10
1.6	COMMENTS ON THIS DEP	11
1.7	DUAL UNITS.....	11
1.8	NON NORMATIVE TEXT (COMMENTARY).....	11
PART II	GENERAL REQUIREMENTS	12
1	AMENDMENT OF ISO STANDARD	12
2	GENERAL	13
3	REQUIREMENTS FOR SPECIFIC MATERIAL GROUPS	13
3.1	GENERAL	13
3.2	STAINLESS STEELS (PREN >13 AND Fe > 50%)	14
3.3	NICKEL ALLOYS (PREN > 26 AND Fe < 50%)	16
3.4	GLASS REINFORCED PLASTICS.....	16
4	SPECIAL MATERIAL REQUIREMENTS	17
4.1	USE OF ISO 10423 (API 6A) MATERIAL CLASSES	17
4.2	WELDING (INCLUDING CLAD AND OVERLAY WELDED EQUIPMENT)	17
4.3	PROTECTION AGAINST CATASTROPHIC FAILURE MECHANISMS	17
4.4	PROTECTION OF STAINLESS STEELS WITH ALUMINIUM	18
4.5	SEALING MATERIALS	18
PART III	MATERIALS SELECTION BY EQUIPMENT SYSTEM.....	19
1	INTRODUCTION	19
1.1	GENERAL	19
2	PRODUCTION SYSTEMS	19
2.1	GENERAL	19
2.2	DOWNHOLE TUBING AND LINERS	20
2.3	CASING	22
2.4	TREES AND DOWNHOLE EQUIPMENT.....	22
2.5	VESSELS AND PIPING.....	24
2.6	PIPING, FITTINGS, VALVES, AND OTHER COMPONENTS.....	26
2.7	SMALL BORE INSTRUMENT, HYDRAULIC AND CHEMICAL INJECTION TUBING	27
2.8	HEAT EXCHANGERS	27
2.9	GLYCOL DEHYDRATION SYSTEM	30
2.10	FLARE AND RELIEF SYSTEMS.....	32
2.11	ROTATING EQUIPMENT	32
2.12	BOLTS	32
2.13	ELASTOMER SEAL SELECTION	34
3	PIPELINES	35
3.1	GENERAL	35
3.2	PROCESS PIPELINES.....	35
3.3	SUBSEA RISERS	37
3.4	DRY HYDROCARBON PIPELINES	37
3.5	WATER INJECTION PIPELINES	37
3.6	UMBILICALS.....	38
3.7	FLEXIBLES.....	39
4	UTILITIES	40
4.1	WATER SYSTEMS.....	40

4.2	INHIBITORS AND OTHER CHEMICALS	45
4.3	MISCELLANEOUS UTILITY SYSTEMS.....	47
4.4	DIESEL FUEL SYSTEMS.....	48
5	STEAM INJECTION SYSTEMS.....	48
5.1	GENERAL.....	48
5.2	PRODUCTION EQUIPMENT	49
6	ENHANCED OIL RECOVERY	50
7	SUBSEA	50
PART IV	AMENDMENTS/SUPPLEMENTS TO ISO 15156.....	54
ISO 15156 Part 1:	General principles for selection of cracking-resistant materials	54
1	Scope	54
5	General principles.....	54
6	Evaluation and definition of service conditions to enable material selection	54
6.1	54	
7	Selection of materials, resistant to SSC/SCC in the presence of sulphides, from existing lists and tables	54
ISO 15156 Part 2:	Cracking-resistant carbon and low-alloy steels, and the use of cast irons 54	
1	Scope	54
7	Qualification and selection of carbon and low-alloy steels with resistance to SSC, SOHIC and SZC	55
7.3	Hardness requirements	55
8	Evaluation of carbon and low alloy steels for their resistance to HIC/SWC	55
Annex A	(Normative) SSC-resistant carbon and low alloy steels (and requirements and recommendations for the use of cast irons)	56
A.2	SSC-resistant carbon and low alloy steels and the use of cast irons	56
Annex B	(Normative) Qualification of carbon and low alloy steels for H₂S service by laboratory testing	56
B.2	Uses of laboratory qualifications	56
B.5	Test procedures and acceptance criteria to evaluate the resistance of carbon and low alloy steels to HIC/SWC	56
ISO 15156 Part 3:	Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys 57	
1	Scope	57
Annex A	(normative) Environmental cracking-resistant CRAs and other alloys (including Table A.1 – Guidance on the use of the materials selection tables)	57
A.1	General	57
A.2	Austenitic stainless steels (identified as material type and as individual alloys)	58
A.3	Highly alloyed austenitic stainless steels (identified as material types and as individual alloys).....	60
A.4	Solid-solution nickel-based alloys (identified as material types and as individual alloys).....	61
A.6	Martensitic (stainless) steels (identified as individual alloys)	62
A.7	Duplex stainless steels (identified as material types)	64
A.8	Precipitation-hardened stainless steels (identified as individual alloys)	66
A.9	Precipitation-hardened nickel-based alloys (identified as individual alloys)	67
A.13	Cladding, overlays and wear-resistant alloys	69

Annex B (normative) Qualification of CRAs for H2S-service by laboratory testing.....69
B.9 Test protocol to identify risk of stress corrosion cracking in CRAs.....69

PART V REFERENCES 70

APPENDICES

APPENDIX A MATERIALS REQUIRING SPECIFIC APPROVAL 74
APPENDIX B QUALIFICATION OF MATERIALS AND MANUFACTURERS 76

PART I INTRODUCTION

1.1 SCOPE

This DEP specifies requirements and gives recommendations for selection of materials in oil and gas 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 sub-surface safety valves, chokes, etc.

However, requirements for instrument tubing used in instrumentation and packaged equipment are included in this DEP. Requirements for pressurized hydrocarbon-containing components in packaged equipment are also included in this DEP.

This DEP is intended to cover materials selection for offshore, onshore and subsea facilities. Materials selection for onshore facilities situated close to marine environments (within 10 km), for facilities in swamp areas or brackish waters, and for locations exposed to wind borne salt contamination, should be based on offshore requirements.

Selection of appropriate materials and design is the preferred approach to avoid catastrophic or sudden failure mechanisms such as stress corrosion cracking, hydrogen embrittlement, (corrosion) fatigue, and low temperature embrittlement.

This DEP is not intended as a purchasing document.

Part IV of the DEP amends ISO 15156:2009.

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 2015 and also incorporates content formerly in DEP 30.10.02.15-Gen., which is now withdrawn. 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 upstream wells and facilities related to exploration and production. 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
Sour Service	Exposure to oilfield environments that contain H ₂ S and can cause cracking of materials by the mechanisms referred to in ISO 15156 (equivalent to NACE MR 175).



1.3.3 Abbreviations

Term	Definition
ABS	Acrylonitrile Butadiene Styrene
CA	Corrosion Allowance
CC	Crevice Corrosion
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CSCC	Chloride Stress Corrosion Cracking
CTDM	Casing and Tubing Design Manual, WS.38.80.31.31-Gen.
DCAF	Discipline Controls and Assurance Framework
EPDM	Ethylene Propylene Diene Monomer
GC	Galvanic corrosion
GRP	Glass Reinforced Plastic (fibreglass). Also known as FRP (fibre reinforced plastic) or GRE (glass reinforced epoxy)
HAZ	Heat-Affected Zone
HE	Hydrogen embrittlement
HIC	Hydrogen-Induced Cracking (also called step-wise cracking, SWC)
HIP	Hot Iso-static Pressed
HRB	Brinell Hardness
HRC	Rockwell hardness
IGSCC	Intergranular Stress Corrosion Cracking
NACE	National Association of Corrosion Engineers
NDT	Non-Destructive Testing
OES	Optical Electron Spectroscopy
PASCC	Polythionic Acid Stress Corrosion Cracking
PE	Polyethylene
PRE_N	Pitting Resistance Equivalent Number

Term	Definition
PTFE	Polytetrafluoroethylene
PVC	Polyvinyl Chloride
PVDF	Polyvinylidene Fluoride
RTP	Reinforced Thermal Plastic
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 Matter Expert
SMSS	Super Martensitic Stainless Steel
SMYS	Specified Minimum Yield Strength
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SSC	Sulphide Stress Cracking
SWC	Stepwise Cracking
SZC	Soft Zone Cracking
TSA	Thermally Sprayed Aluminium
UNS	Unified Numbering System

1.4 CROSS-REFERENCES

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

1.5 SUMMARY OF MAIN CHANGES

This DEP is a revision of the DEP of the same number dated February 2015, which also incorporates content formerly in DEP 30.10.12.15-Gen., which is now withdrawn. The main changes implemented during the review are:

Section/Clause	Change
Throughout	Correct specification of requirements; removal of conflicting requirements; removal of requirements covered in other DEPs; movement of notes from outside Tables to be included in the appropriate Table; removal of requirements from Tables; removal of Trade-names.
	Removal of reference to DEP30.48.00.32 (content being incorporated into 30.48.00.31) and DEP39.01.10.30, which have been withdrawn.
Part II	
3.2.2	Removed from Specification.
Part III	
2.2	Remove reference to compliance checks covered in other DEPs.
	Clarification of 'small' and 'large' CS products.
3.3	Removal of reference to Riser Design DEPs.
3.7	Removed specific reference to degradation and corrosion fatigue from Specification.
4.1.3	Removed references to seawater system material selection from Specification.
Part IV	
Annex B	'shall' requirements retained, remaining text removed from Specification.
Appendix B	
B.3	Removed from Specification.

1.6 COMMENTS ON THIS DEP

Comments on this DEP may be submitted to the Administrator using one of the following options:

Shell DEPs Online (Users with access to Shell DEPs Online)	Enter the Shell DEPs Online system at https://www.shelldeps.com Select a DEP and then go to the details screen for that DEP. Click on the "Give feedback" link, fill in the online form and submit.
DEP Feedback System (Users with access to Shell Wide Web)	Enter comments directly in the DEP Feedback System which is accessible from the Technical Standards Portal http://swwww.shell.com/standards . Select "Submit DEP Feedback", fill in the online form and submit.
DEP Standard Form (other users)	Use DEP Standard Form 00.00.05.80-Gen. to record feedback and email the form to the Administrator at standards@shell.com .

Feedback that has been registered in the DEP Feedback System by using one of the above options will be reviewed by the DEP Custodian for potential improvements to the DEP.

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.

1.8 NON NORMATIVE TEXT (COMMENTARY)

Text shown in italic style in this DEP indicates text that is non-normative and is provided as explanation or background information only.

Non-normative text is normally indented slightly to the right of the relevant DEP clause.

PART II GENERAL REQUIREMENTS**1 AMENDMENT OF ISO STANDARD**

1. Part IV of this DEP is written as amendments and supplements to ISO 15156:2009. Wherever reference is made to ISO 15156, it shall be understood to mean ISO 15156:2009 as amended/supplemented by this DEP.
2. For ease of reference, the clause numbering of ISO 15156 has been used throughout Part IV of this DEP.
3. Clauses in ISO 15156, which are not mentioned in this DEP, shall remain valid as written.

2 GENERAL

1. For determination of concentrations of H₂S, refer to DEP 25.80.10.18-Gen.
2. If the hydrogen sulphide (H₂S) concentration present in the equipment over the lifecycle will exceed either 3 mbar (0.05 psi) partial pressure H₂S in the gas phase or 10 ppm_{mass} in any aqueous phase, then the requirements of (Part IV) of this DEP shall apply.
3. Where concentrations of H₂S are below either 3 mbar (0.05 psi) partial pressure H₂S in the gas phase or 10 ppm_{mass} in any aqueous phase:
 - a. Refer to DEP 39.01.10.11-Gen., clause 7.3.3 for the risk of HIC for life cycles greater than 25 years and for steel wires in flexible pipes.
 - b. Refer to ISO 15156-2 for determining resistance to hydrogen embrittlement and for specifying the requirements for design of high strength, low alloy steels (actual yield strength greater than 140 ksi (965 MPa)).
 - c. For the SSC and SCC resistance of alloys of modified 13Cr-1Mo and 13Cr with SMYS > 95 ksi (655 MPa) refer to (Part IV, A.6.2).
4. When assessing material suitability for design, the pH and H₂S partial pressure shall represent not only the intended normal exposures during the service life, but also exposures as can reasonably be expected to occur during one of the following:
 - a. an unintended process or treatment upset;
 - b. as a result of salt deposition;
 - c. a stratified flow condition;
 - d. as a result of completion leakage into the first well annulus;
 - e. production of completion and spent stimulation fluids back to the host facility.
5. Any proposed changes as a result of conditions encountered that are not adequately covered in this DEP, or if the Contractor wishes to consider less conservative materials choices in the interest of potential cost savings, shall be subject to approval of the Materials & Corrosion Technical Authority of the Principal.
6. When conversions between sodium chloride concentration in mg/l and g/l are made, the atomic weights of sodium and chloride should be taken into consideration (Cl⁻ amounts to 61% by mass of NaCl).

In ISO 15156 and in (Part IV) of this DEP, concentrations of sodium chloride in the corrosive phases are expressed as chloride concentrations [Cl⁻] in mg/l, whereas in Part III, they are expressed as sodium chloride concentrations [NaCl] in g/l. (Cl⁻ amounts to 61% by mass of NaCl).
7. Molybdenum disulphide SHALL [PS] not be used in any service.
8. Selection of CRA for small bore pipework ND50 (NPS 2) and below should be considered to minimise lifecycle cost.

3 REQUIREMENTS FOR SPECIFIC MATERIAL GROUPS

3.1 GENERAL

1. For vessels, internal protective coatings may be applied to protect carbon and low alloy steels against hydrogen induced cracking (HIC) or stepwise cracking, provided that the coating integrity is maintained and that it is possible to monitor HIC by NDT.

3.2 STAINLESS STEELS (PREN >13 AND Fe > 50%)

3.2.1 General

1. Use of proprietary alloys shall be subject to approval of the Principal.

3.2.2 High chloride exposures

1. The production stream phase behaviour shall be reviewed during detailed design to identify whether flashing conditions or salt deposition from carryover fluids can take place, which could lead to localised concentration of fluid salinity and cracking of stainless steels.
2. If localised concentration of fluid salinity can occur, either a salinity of 250 g/l (expressed as NaCl) or the greater value equivalent to salt saturation in water at operating conditions SHALL [PS] be used when selecting and testing the material.
3. All testing involving halides shall be done in representative water chemistry.
4. The temperature thresholds given in Table 1 Columns 1 and 2 shall be used to assess the risk of pitting and crevice corrosion in offshore and onshore salt laden oxygenated environments and the requirements for mitigation against pitting or crevice corrosion if deemed necessary, refer to (4.3, item 2).
5. The temperatures given in Table 1 Column 3 shall be used as default values for the basis of design where no mitigation against CSCC is required.
6. Application of stainless steels at the temperatures given in Column 4 shall require mitigation against CSCC.
7. Application of stainless steels at temperatures given in Column 5 shall require mitigation against CSCC, and
 - a. shall be subject to approval by the Materials & Corrosion Technical Authority of the Principal.

8. The risk associated with use of stainless steel types not covered in Table 1 shall be subject to approval of the Materials & Corrosion Technical Authority of the Principal.

Table 1 Application limits for stainless steels in salt laden, oxygen contaminated exposures (6)

	1	2	3	4	5
Stainless steel type⁽¹⁾	Threshold for pitting corrosion	Threshold for crevice corrosion	Negligible risk of C SCC	Risk of C SCC at high chloride concentration⁽²⁾	Significant risk of C SCC
316L ⁽³⁾	5°C (41°F)	<0°C (<32°F)	<20°C (<68°F)	20-50°C (68-122°F)	>50°C (>122°F)
6Mo	50°C (122°F)	30°C (86°F)	<100°C (<212°F)	100-120°C (212-248°F)	>120°C (>248°F)
22Cr Duplex ⁽⁴⁾	40°C (104)°F	15°C (59°F)	<70°C (158°F)	70-100°C (158-212°F)	>100°C (>212°F)
25Cr Super-duplex ⁽⁵⁾	60°C (140°F)	30°C (86°F)	<80°C (176°F)	80-100°C (176-212°F)	>100°C (>212°F)
NOTES: 1. Table gives requirements for generic stainless steel types. Specific materials and conditions may influence the acceptable temperature. 2. High concentration is, e.g., due to chloride deposition from evaporation. 3. Assumes minimum Molybdenum content of 2%. Higher temperatures may be validated at higher Mo content. 4. Assumes PRE _N > 35 5. Assumes PRE _N > 40 6. Exposures where wet salt deposit or halides (chlorides) above 100 ppm are present and oxygen contamination in the aqueous phase may be above 20 ppb, including exposures to salt laden moist air, injection water, residual hydrotest water, and cooling waters.					

9. Materials selection shall include the condition of external salt deposition in marine service, and for onshore in high salinity locales from conditions such as salt laden sand.
10. Contact of zinc with safety critical stainless steel equipment SHALL [PS] be prevented. Contact includes zinc containing coatings and contamination by zinc in fire scenarios from other equipment but not electroplated zinc or zinc-nickel fasteners.

3.2.3 Ferritic and Martensitic stainless steels

- Weldable 13Cr (SMSS) is susceptible to intergranular stress corrosion cracking (IGSCC) and any application shall be validated by a test program at process conditions subject to approval of the Principal.
- Refer to DEP 30.10.60.18-Gen., section 4 for requirements pertaining to the applicable welding procedure specifications.

3.2.4 Austenitic and Duplex stainless steels (<6% Mo)

1. Austenitic stainless steels containing the same or lower chromium, nickel and molybdenum than AISI 316L, shall not be applied.
2. Austenitic/ferritic stainless steels (duplex stainless steels) can suffer both SCC and SSC, hence:
 - a. hardness requirements from (Part IV) of this DEP shall apply, and
 - b. H₂S partial pressure limits shall be followed as given in (Part III) and (Part IV).
3. 22Cr Duplex and 25Cr Super-duplex stainless steels are susceptible to CSCC at > 70°C (158 °F) to 80 °C (176 °F) under drop evaporation conditions, and therefore use at points of salt accumulation shall be avoided.

In this DEP, the term 25Cr Super-duplex stainless steel implies duplex stainless steels with 25% Cr and PRE_N > 40.

3.2.5 Super austenitic stainless steels (>6 % Mo)

1. To ensure corrosion resistance of welds, a nickel alloy filler with increased Mo, such as Alloy 625, shall be used.

3.2.6 Precipitation hardened stainless steels

1. Use of precipitation hardened stainless steels (refer Appendix A), SHALL [PS] be subject to approval of the Materials & Corrosion Technical Authority of the Principal.

3.3 NICKEL ALLOYS (PREN > 26 AND Fe < 50%)

1. The use of proprietary alloys shall be subject to approval of the Principal.
2. For use of UNS N07718 (Alloy 718), UNS N07725 (Alloy 725) and UNS N07716 (Alloy 625+), refer to DEP 39.01.10.32-Gen.
3. Alloy N08825 (Alloy 825) shall be supplied with Nickel content greater than 39% and a PREN greater than 30.
4. Where galling resistance is required, anti-galling compounds, electroplating, or use of different materials shall be used for the two parts that come into contact, e.g., N06625, N07725.
 - a. Electroplating of precipitation hardened nickel alloys shall be subject to review and approval of the Principal.
 - b. An alternative anti-galling approach that may be used is to specify and assure a minimum difference in hardness of 25 HRB of the components.

3.4 GLASS REINFORCED PLASTICS

1. For details regarding the choice of fibre and resin, refer to DEP 30.10.02.13-Gen.
2. For use of GRP pipelines and piping, refer to DEP 31.40.10.19-Gen.

4 SPECIAL MATERIAL REQUIREMENTS

4.1 USE OF ISO 10423 (API 6A) MATERIAL CLASSES

1. In Table 3 of ISO 10423, low alloy steels should be UNS G41300 (AISI 4130), UNS G86300 (AISI 8630), ASTM A182 Grade F22 materials, and ASTM A694 Grades F56, F60 and F65.
2. Stainless steel castings shall be ASTM A743 Grade CA6NM.
3. Where CRAs are specified for wellhead and subsea hardware, materials that shall be used are:
 - a. overlay welded Alloy 625 (UNS N06625);
 - b. solid 25Cr Super-duplex Stainless Steel;
 - c. solid 22Cr Duplex Stainless Steel.
4. The manufacturing qualification procedure, including heat treatment shall be subject to approval by the Principal.
5. Reference to "trim" in the context of ISO 10423 shall apply to pressure controlling parts of the component (e.g. seal faces, gates, stems, choke inserts, and mandrel hangers), but not to the body of the component.

4.2 WELDING (INCLUDING CLAD AND OVERLAY WELDED EQUIPMENT)

1. For welding, refer to DEP 30.10.60.18-Gen. or DEP 30.10.60.32-Gen.
2. Procedures involving welding or buttering of ferritic or martensitic materials with austenitic consumables shall be evaluated using a micro-hardness survey subject to approval by the Principal.

This is to assess whether a thin, hard, brittle zone of relatively high carbon has formed in the austenitic material immediately adjacent to the fusion boundary.

 - a. If hard zones (Hv10 > 325) are identified, exposure of such hard zones to sour conditions or cathodic protection SHALL [PS] be avoided.
 - b. When carrying out buttering, the closure weld shall be made with UNS N06625 (Alloy 625).
3. Maximum hardness of 275 HV 10 in the base metal and HAZ may be accepted for non-sour and sour service, provided that the equipment is fully clad. Refer to ISO 15156-3, Clause A13.1.
4. Overlay weld cladding shall consist of a minimum of two layers.
5. 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 be 10%, or 5% if in Region 3 defined by ISO 15156-2 (severe sour service).
6. Optical electron spectroscopy (OES) shall be used to determine weld dilution.

4.3 PROTECTION AGAINST CATASTROPHIC FAILURE MECHANISMS

1. Coatings or corrosion inhibition shall not be used as primary barriers to stress corrosion cracking or corrosion fatigue during design.
 - a. Coatings including TSA may be considered for mitigation of external CSCC if the risk is assessed as manageable, refer to (Part II, 3.2.2) of this DEP.
 - b. If temperatures increase due to change of use (e.g. due to tie-ins) such that the chloride stress corrosion cracking temperature limit is exceeded (refer to Table 1), the use of coating or aluminium foil as mitigation shall be subject to approval by the Materials & Corrosion Technical Authority of the Principal.

4.4 PROTECTION OF STAINLESS STEELS WITH ALUMINIUM

1. Stainless steels may be protected against external pitting and crevice corrosion by:
 - a. coating with thermally sprayed aluminium (TSA), refer to DEP 30.48.40.31-Gen.
 - b. using sealed, 60 mm (2-½ mil) foil, refer to DEP 30.46.00.31-Gen.
2. The applicable temperature range for the use of aluminium foil under insulation shall be 50 °C – 200 °C (122 °F – 392 °F).
3. TSA shall not be used for protection of small-bore (<DN 50) (<NPS 2) components.
4. TSA shall not be applied to stainless steels in subsea applications.

4.5 SEALING MATERIALS

1. To prevent galvanic corrosion where metal-to-metal seals are used, the seal surface material shall be at least as noble as the surrounding surfaces.
2. For selection of elastomer seals, refer to DEP 30.10.02.13-Gen.

PART III MATERIALS SELECTION BY EQUIPMENT SYSTEM**1 INTRODUCTION****1.1 GENERAL**

(Part III) includes materials requirements for process and utility equipment used in onshore, offshore, and subsea operations for exploration and production.

1. The application of materials listed in the material classes in (Appendix A, Table A.1) shall be subject to approval of the Principal.
2. If the corrosion rate is known from service experience or prediction, then the service life corrosion (SLC) figure should be used for materials selection.
3. If the corrosion rate is not known, basic operating condition data may be used to determine possible materials options.
4. Materials may be qualified for service outside the conditions indicated in the following sections subject to approval by the Materials & Corrosion Technical Authority of the Principal.

2 PRODUCTION SYSTEMS**2.1 GENERAL**

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

1. The material selected shall meet minimum toughness requirements at the minimum design temperature during low temperature events such as blowdown; for low temperature requirements of materials, refer to DEP 30.10.02.31-Gen.

2.2 DOWNHOLE TUBING AND LINERS

1. For material selection for downhole tubing, production casing, and liners in production and injection exposures, refer to Table 2.
 - a. Other exposures including well brines, packer fluids, and stimulation acids, shall be included in the materials selection assessment.
 - b. Refer to Appendix A for other restrictions.
2. For specific well design, refer to the Casing and Tubing Design Manual, WS 38.80.31.31-Gen.
3. For water injection tubing materials selection, refer to DEP 31.01.10.11-Gen.
4. Use of GRE shall be limited by the combination of pressure and applied diameter, refer to DEP 30.10.02.13-Gen. and DEP 31.40.10.19-Gen.
 - a. The limitations on wall thickness: diameter ratio shall also be applied.
 - b. Limitations on the maximum string length in terms of load bearing capacity (ratio of strength to density) shall be included in the assessment.

Pressure limits in these DEPs refer to 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.

5. Use of GRE-lined CS shall be limited to products qualified by testing or subject to approval of the Principal.

Smaller diameter (e.g., 5") GRE-lined CS may be qualified by larger diameter product (e.g., 7").

 - a. Carbon steel base material shall meet the same requirements for CS in sour service.
 - b. Chemical compatibility, such as stimulation acids, and the impact of gas depressurization shall be assessed.
 - c. In deviated wells, wear issues shall be assessed and other approved tubing materials installed at kick-off points as needed.
6. The use of carbon steel shall include an assessment of SLC and the required wall allowance during the well life.
 - a. Downhole corrosion inhibition, either continuous above the deepest injection point or batch above the point of liquid fill, may be considered for mitigation of SLC when using CS.
7. Coated tubing shall not be considered as a method of improving corrosion time to failure.
 - a. Coated production tubing, both carbon steel and CRA, may be considered as a mitigation of work over costs (e.g., reduced fishing), enhanced tubing reuse, and improved flow performance.
8. Requirements to address elemental sulphur deposition shall be subject to approval of the Materials & Corrosion Technical Authority of the Principal.

Table 2 Downhole production tubing, liners, and casing¹

Production	Conditions				Material
	SLC ⁽⁶⁾	Temp.	Sour Regions H ₂ S ⁽²⁾	NaCl ⁽⁹⁾	
	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)	Region 0	Any	CS, ISO 11960, any strength grade.
Water contact with walls (Corrosive or sour service)	<3 (<1/8)	<200 (<392)	Region 1	Any	CS, ISO 11960, any group 2 grade, plus any grade per ISO 15156-2 Table A.3 temperature limits ⁽³⁾
	<3 (<1/8)	<200 (<392)	Regions 2 or 3+	Any	CS, ISO 11960 Q+T grades with hardness ≤ 250 HV 10 (≈ 22HRC) and C90 and T95 grades ⁽³⁾
	<3 (<1/8)	80-200 (176-392)	Regions 2 or 3+	Any	CS, ISO 11960 Grade P110 or other ISO 11960 CS with max. 140 ksi yield strength.
	<3 (<1/8)	110-200 (230-392)	Regions 2 or 3+	Any	CS ⁽⁵⁾ , ISO 11960 Grade Q-125 or other ISO 11960 CS ⁽⁵⁾ with max. 150 ksi yield strength.
Water contact with walls (Corrosive sweet service, i.e., "non-sour" service)	N/A	<140 (<284)	<3.5 (<0.05)	<165	13Cr super (>1.5%Mo). See CTDM for approval requirements for broader application limits. Exposure shall be limited to pH ≥ 3.5.
	N/A	<200 (<392)	<3.5 (<0.05)	<20	
	N/A	<140 (<284)	(See CTDM)	<165	For 13Cr modified (0.5-1.5%Mo), see CTDM for approval requirements for application limits ⁽⁴⁾ . Exposure shall be limited to pH ≥ 3.5.
	N/A	<200 (<392)		<20	
Water contact with walls (Corrosive sweet service, i.e., "non-sour" service)	N/A	<140 (<284)	<3.5 (<0.05)	<165	13Cr super (>1.5%Mo). See CTDM for approval requirements for broader application limits. Exposure shall be limited to pH ≥ 3.5.
	N/A	<170 (<338)	<10 (<1.5)	<20	
	N/A	<200 (<392)	<20 (<0.30)	<250	22Cr Duplex Stainless Steel (125 - 140 ksi)
	N/A	<200 (<392)	<100 (<1.45)	<250	25Cr Super-duplex Stainless Steel (125 - 140 ksi)
	N/A	<200 (<392)	<5500 (<80)	<250	SM 2535 (125 -140 ksi)
	N/A	<200 (<320)	<14,000 (<203)	<250	Alloy 825 (125-140 ksi)
	N/A	<160 (<320)	<14,000 (<203)	<250	Alloy 28 (125 -140 ksi)
	N/A	<200 (<392)	<36,000 (<522)	<250	Alloy 28 (pCO ₂ <25 bar) (125 - 140 ksi)
	N/A	<200 (<392)	<80,000 (<1160)	<250	Alloy 2550/G3
Wet/dry oil/condensate	N/A	<280 (<568)	<120,000 (<1740)	<250	Alloy C276/C22/G50
	N/A	<110 (<230)	Any	No limit	GRE lined CS (Host pipe shall be as required for sour service.)
	N/A	<100 (<196)	Any	No limit	GRE

NOTES:	(1) For welded product limitations, see Table 3. (2) SSC regions as defined in Figure 1 of ISO 15156-2. H ₂ S pressures refer to partial pressures of H ₂ S. Refer to ISO 15156-1. Where no gas phase is present, the fugacity will be substituted for the partial pressure. For region 4 refer to the CTDM. (3) Where necessary, higher strength grades may be qualified for a specific application per CTDM requirements. (4) Specific S13Cr materials can be proprietary and may require testing under simulated well conditions per CTDM requirements to confirm applicability for service. (5) 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 shall not be used. (6) The SLC is the excess wall allowance beyond that needed for design per the well's design standards. It is Not Applicable (N/A) to CRA usage. (7) Includes associated strength grades to a maximum 655 MPa (95 ksi) yield. (8) Materials in this section may also be applied in sweet service. (9) ANY on NaCl means <250, not proven for saturated conditions
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2.3 CASING

1. Corrosion shall be controlled by the use of oil base fluids or by brines using stable pH buffers, oxygen scavengers, and biocides (below 100 °C).
2. Selection of production casing grade where a short-term exposure to produced fluids may occur SHALL [PS] be based on the carbon steel entries of Table 2.
3. For selection of casing continuously exposed to produce fluids where cracking or estimated corrosion of such casing might compromise well integrity, refer to Table 2.

2.4 TREES AND DOWNHOLE EQUIPMENT

1. For selection of suitable materials for Trees, refer to Table 3 and the restrictions noted in (Appendix A).
2. The materials for construction of subsea Tree flow loops shall be 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 3.
3. Sealing surfaces shall be overlaid with Alloy 625 where there is a potential for crevice corrosion, for more information, refer to (3.2) requirements.
4. Only audited and qualified Suppliers of AISI 410 shall be used.
5. Refer to DEP 39.01.10.32-Gen. for requirements for precipitation hardened nickel alloys.
6. For subsea Trees, refer to (Part III, 7).
7. Requirements to address elemental sulphur deposition shall be subject to approval of the Materials & Corrosion Technical Authority of the Principal.

Table 3 Trees and downhole equipment¹

Conditions				Material
Temp	pH ₂ S	NaCl (chlorides)	Other	
°C (°F)	mbar (psi)	g/l		
Wellhead and downhole components, sweet service				
Any	<3.5 (<0.05)	<200 (120)	SLC <3	Carbon steel with stainless or CRA trims.
<140 (<284)	<3.5 (<0.05)	<165 (100)	SLC>6	Martensitic stainless steel (F6NM/CA6NM) with stainless or CRA trims.
<200 (<392)		<20 (12)	SLC>6	
Wellhead and downhole components, sour service				
<140 (<284)	<5 (<0.07)	<165 (100)	pH >3.5	Martensitic stainless steel (F6NM/CA6NM) with stainless or CRA trims.
<200 (<392)		<20 (12)	pH >3.5	
<200 (<392)	<10 (<0.15)	<250 (150)	SLC>6	22Cr Duplex with CRA trims.
<200 (<392)	<20 (<0.29)	<250 (150)	SLC>6	25Cr Super-duplex CRA trims.
<200 (<392)	<80 (<1.16)	<50 (30)	SLC>6	25Cr Super-duplex CRA trims.
<200 (<392)	<5,000 (<73)	<200 (120)	SLC>6	Alloy 718 or Alloy 925 with CRA trims, Alloy 625/725 sealing faces ⁽²⁾ preferred.
<232 (<450)	<27,580 (<400)	<300 (180)	SLC>6	Alloy 935
<205 (<401)	<35,025 (<508)	<300 (180)	SLC>6	Alloy 945
<232 (<450)	<35,025 (<508)	<230 (139)	SLC>6	
<240 (<392)	<30,000 (<435)	<250 (150)	SLC>6	Alloy 625 type, e.g., Alloy 625+, Alloy 625PH or Carbon steel clad throughout with Alloy 625 ⁽²⁾
<240 (<392)	<51700 (<750)	<250 (150)	SLC>6	Alloy 725
Springs				
<240 (<392)	<51700 (<750)	<250 (150)	SLC>6	MP35N
Sand screen wire (for base pipe see Table 2)				
<120 (<248)	<3.5 (<0.05)	<250 (150)	SLC>6	316
<160 (<320)	<14,000 (<203)	<250	SLC>6	825

NOTES:	(1a)	For welded components, refer to Table 3.
	(1b)	For instrument line materials, refer to Table 2.
	(1c)	For subsea wellhead applications refer to (Part III, Section 7, Table 26).
	(2)	At lower H ₂ S levels, higher CO ₂ levels can be allowed. <i>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.</i>
	(3) and (4)	no longer used

2.5 VESSELS AND PIPING

Refer to (Part III, 2.9) for requirements that apply to glycol contactor and regeneration system vessels. Refer to (Part III, 4) for requirements that apply to utility systems, including water systems.

1. 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.
2. CRA cladding and lining may be full or partial depending upon the assessed corrosivity.
 - a. If partial cladding or lining is selected, this shall be subject to approval by the Principal.
3. For materials selection for vessels, refer to Table 4 and DEP 31.22.00.31-Gen.
4. Materials selection shall be based upon the cumulative corrosion loss estimated for the SLC and other internal environment constraints.
5. For the carbon steel host in a fully clad vessel, the material specified shall:
 - a. follow any sulphur limitations given in DEP 39.01.10.11-Gen., Table 9;
 - b. identify no specific requirement for HIC testing of the steel;
 - c. provide assurance in the design and fabrication that the cladding is continuous over the whole vessel surface.
6. CRA clad vessels shall not require a corrosion allowance to be applied to the carbon steel underneath the cladding.
7. Materials selection shall include an assessment of the risk of Polythionic acid stress corrosion cracking (PASCC) of austenitic stainless steels.

PASCC can occur when austenitic stainless steels are in sour service and are exposed to air contamination.
8. For guidance on internal coating of vessels and piping, refer to DEP 30.48.00.31-Gen.
9. Vessel linings (e.g., glass flake epoxy systems) shall not be selected for high corrosion rate systems or where significant erosive particles are anticipated.
 - a. Where linings are used, the vessel shall be scheduled for internal inspection 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.
10. Zinc or aluminium anodes may be used in conjunction with linings in vessels 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;
 - c. sufficient corrosion allowance is available for vapour phase corrosion;
11. For materials for vessel internals, (e.g., weirs, baffles), refer to Table 4.
12. Internals with higher flow than at the vessel wall should be a stainless steel material appropriate to the service environment; refer to Table 4.
13. Stainless steel materials in water immersion service in a carbon steel vessel shall be coated.