

Guidelines for materials selection and corrosion control for subsea oil and gas production equipment

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THE ENGINEERING EQUIPMENT AND MATERIALS USERS' ASSOCIATION

Guidelines for materials selection and corrosion control for subsea oil and gas production equipment

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ENGINEERING EQUIPMENT AND MATERIALS USERS' ASSOCIATION

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Foreword

Although subsea well completions, manifolds, flowlines and associated equipment have been used for around forty years, there is a continuing need for increased, up-to-date guidance and awareness of materials selection and performance, the reasons for which are expanded upon in the Introduction.

Accordingly, this Publication was developed by EEMUA's Materials Technology Committee (MTC), first published in 1999 and updated in the Second Edition in 2004. Since then, significant further developments in subsea materials technology and operational experience have occurred. These have been captured in this Third Edition which has been completely updated by a specialist Work Group of MTC. This Group comprised metallurgists and corrosion engineers with particular expertise in the subsea environment and was drawn from leading oil and offshore engineering companies.

Extensive reference is made in the text to various industry, national and international codes and standards. As this Publication is intended as a guide and not a specification, such references are for guidance only. A comprehensive list of references is given in Appendix I.

Phrases such as 'at present' or 'currently' are used in the text to indicate conditions at the time of writing this Third Edition, i.e. 2011.

Abbreviations used in this Publication are listed in Appendix VIII.

EEMUA Subsea Materials & Corrosion Frequently asked questions

Who runs Subsea Materials & Corrosion?

This course has been developed and is administered by the Engineering Equipment and Materials Users' Association (EEMUA), a European industry Association with headquarters in London. EEMUA's engineering guides, standards and training schemes are recognised and followed worldwide. See www.eemua.org.

The course is operated in association with the Society for Underwater Technology (SUT). The SUT is an international learned society actively promoting the development, dissemination, and exchange of ideas, information and technology arising from or related to the underwater environment. The Society brings together organisations and individuals from over 30 countries with a common interest in subsea technology, ocean science and offshore engineering. For more details, visit www.sut.org.uk.

The principal course presenters will be materials and corrosion specialists from major offshore/subsea operating companies; in addition, guest speakers are invited from equipment vendors and subsea contractors.

When and where will the courses be held?

Courses are planned at regular intervals in the UK. Courses elsewhere in the world may be organised from time to time, depending on demand. The language is English. For the latest details of all future courses, dates and locations, visit the EEMUA website www.eemua.org or contact EEMUA directly by phone or e-mail (see below).

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A Training Course from EEMUA in association with SUT

A two and half day training course for engineers and others involved in the design, specification, commissioning, operation, maintenance, repair or refurbishment of underwater oil and gas production equipment and related facilities



SUBSEA ENGINEERING

Materials selection and corrosion control

for subsea oil and gas production equipment



1. Introduction

This EEMUA Publication is aimed at engineers and others involved in the design, specification, commissioning, operation, maintenance, repair or refurbishment of underwater oil and gas production equipment and related facilities. It provides an overview of the current knowledge of the principles and practices of materials selection and corrosion control for these facilities. Guidance on the application of such knowledge is considered necessary because:

- Some expensive subsea materials-related failures have occurred over recent years.
- The complexity of subsea equipment is continually increasing: items such as multiphase pumps, separators and water injection facilities are becoming more commonly specified.
- The amount of hydrocarbons recovered from subsea developments is set to continue to increase in the future, hence the reliability of subsea equipment has become increasingly important for the producing companies.
- Deep water developments have become more common, and the performance of materials in such environments is not well understood and documented at present.
- Reservoir fluids from marginal fields may become increasingly corrosive/erosive.
- Relatively little detailed guidance is available in existing industry codes, standards, etc.
- The integrity of subsea equipment is paramount for protection of the environment.

At the time of this revision, some areas of subsea materials technology are continuing to evolve, hence the associated information in this EEMUA Publication should be supplemented or qualified by the latest knowledge and experience. In order to help readers maintain their knowledge up-to-date, EEMUA has developed a 2½-day training course based on the Publication but incorporating the latest experience. This EEMUA course, in association with the Society for Underwater Technology (SUT), is held annually in the UK and at various locations around the world, subject to demand. A summary of the course is provided on the facing page. See www.eemua.org for more details.

In order to assist with further updating of this Publication to ensure its continued relevance, EEMUA would welcome feedback from users of their experiences regarding materials performance in the subsea environment.

2. Scope

2.1 Technical Guidance

This Publication sets out the principles and practices of materials selection and corrosion control, and provides information on lessons learned in the industry. Key aspects of welding and fabrication are also discussed. However it should not be seen as an alternative to the involvement of suitably qualified metallurgical and corrosion specialists in subsea projects. Indeed, the complexity of some of the issues involved is such that the document cannot always provide definitive recommendations, and the requirement for expert advice on materials issues will remain.

There are many associated topics that could affect materials performance and equipment integrity that are not addressed in any detail in this document, for example:

- welding and cladding procedures,
- weld defect acceptance criteria,
- non-destructive examination requirements,
- QA/QC procedures during component manufacture,
- verification and validation testing of assembled equipment,
- chemical treatment of hydrotest fluids,
- methods of deployment of equipment to avoid sea water ingress, and
- subsea connection procedures to avoid or minimise sea water ingress.

2.2 Extent of Application

This Publication relates to equipment fully immersed in sea water installed at or above the seabed for oil and gas production, including water, gas and chemical injection systems and their associated controls—essentially everything from the wellheads downstream to the delivery point to the surface facilities. The equipment is that typically associated with subsea developments, using either tie-backs to fixed platforms, or an arrangement of rigid or flexible risers to floating production units which could be semi-submersibles or monohull vessels.

The emphasis is on the identification and discussion of those materials- and corrosion-related issues which are specific to subsea equipment and which are not usually encountered in offshore platform-based designs utilising dry completions.

Outside the scope are:

- drilling and downhole equipment;
- items used only for the deployment, retrieval or maintenance of the permanently installed facilities (though the materials used for such equipment should be subjected to review, based on the principles in this document. At least one serious incident is known to have occurred due to rapid galvanic corrosion of aluminium components in deployment equipment. Failures of high strength fasteners used in lifting and deployment equipment have also been reported);
- structural items and steel fabrications (Ref ISO 13628-15); and
- topside equipment.

3. General Principles of Materials Selection and Corrosion Control

3.1 Reference Standards

The most relevant and useful reference documents which relate specifically to subsea materials selection and corrosion control are currently those listed below. Some are quite detailed and give clear materials requirements, but usually without supporting explanations. Others deal with materials rather more superficially.

Most of the relevant international documents have been issued as a suite of ISO standards, which are currently numbered as ISO 13628-1 to -15, Design and Operation of Subsea Production Systems—Parts 1 to 15. These have in general been developed from, and in many cases are identical to, the ANSI / API 17 series of documents, as listed in Table 1.

Table 1 Relevant standards for subsea equipment*

ISO	Equivalent ANSI / API
13628-1: General Requirements & Recommendations	RP 17A: Design & Operation of Subsea Production Systems (co-branded ISO 13628-1)
13628-2: Unbonded Flexible Pipe Systems for Subsea & Marine Applications	Spec 17J: Unbonded Flexible Pipe
13628-3: Through Flowline (TFL) Systems	RP 17C: TFL (Through Flowline) Systems (co-branded ISO 13628-3)
13628-4: Subsea Wellhead & Tree Equipment	Spec 17D: Subsea Wellhead & Tree Equipment
13628-5: Subsea Umbilicals	Spec 17E: Specification for Subsea Umbilicals
13628-6: Subsea Production Control Systems	Spec 17F: Specification for Subsea Production Control Systems (co-branded ISO 13628-6)
13628-8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems	RP 17H: Remotely Operated Vehicles (ROV) Interfaces on Subsea Production Systems
13628-10: Specification for Bonded Flexible Pipe	Spec 17K: Specification for Bonded Flexible Pipe
13628-11: 2007 Flexible Pipe Systems for Subsea & Marine Applications	RP 17B: Flexible Pipe (contains full text of ISO 10420)
13628-15: Subsea Structures and Manifolds	
—	Spec 17G: Design and Operation of Completion/Workover Riser Systems

**Notes: Annex A to ISO 13628-1 includes descriptions of the various components of a subsea production system. It is a useful guide for those unfamiliar with such systems. Other relevant subsea documents include NORSOK Standard M-001 Materials Selection subsec. 5.6 'Subsea production and flowline systems'.*

Some guidance is also given in ISO 21457 'Materials selection and corrosion control for oil and gas production systems'. This was first published in 2010 and

its scope includes surface and subsea facilities. Due to the breadth of its scope, the level of detail is limited. However, cross references to this ISO standard are made within this EEMUA Publication where appropriate.

3.2 The Need for Integrity

Integrity, in the context of subsea equipment, usually means:

- reliable operability with minimal intervention, and
- no loss of containment of hazardous or toxic fluids.

Failure of subsea pressure boundary equipment by corrosion or cracking will usually result in some environmental impact—possibly serious in the case of hydrocarbons and chemicals. The feasibility of condition monitoring of equipment to prevent such incidents needs to be considered during materials selection. Subsea equipment, by its very nature, is far more difficult and expensive to inspect and maintain than its equivalent topside or onshore. This is particularly the case in deep water developments where divers cannot operate. Some equipment items, particularly in complex and compact assemblies such as manifolds, can only be properly inspected by retrieval to the surface. Currently available inspection and condition monitoring technologies include the following:

- general visual/ROV inspection,
- internal corrosion/erosion monitoring of flowlines and pipelines,
- sand detection,
- cathodic protection surveys,
- intelligent pigging of pipelines,
- ultrasonic thickness surveys,
- external crack detection,
- bolt/stud crack detection,
- vibration/movement measurements,
- stress/strain monitoring, e.g. of dynamic risers and umbilicals,
- leak detection (visual, acoustic, laser),
- functionality testing of remotely actuated and ROV operated valves,
- monitoring of status of subsea sensors (temperature, pressure, sand, etc.),
- non-metallic materials degradation monitoring, e.g. textile rope coupons,
- monitoring flexible piping annulus fluids,
- eddy current inspection of flexible pipe armour wires, and
- electrical resistance integrity tests for control system umbilicals.

Failure of non-pressure boundary equipment that impairs or even prevents operability can be equally expensive to correct, both in terms of the cost of intervention and the value of deferred or lost production. In this context, even small and seemingly minor items can become profoundly important if they fail in service, e.g. set screws mounting a hydraulic control valve onto a panel, or a circlip retaining an umbilical coupler in its mounting.

Fabrication and welding play an important role in equipment integrity and it is essential that appropriate and qualified procedures are in place for these activities. It is recommended that fabricators should be accredited to ISO 3834.

The overall picture is that increasing water depth and field life favour a trend towards a 'fit and forget' philosophy, where increasingly robust materials and

designs are employed, and reliance on in-service inspection and monitoring is kept to a minimum.

3.3 Equipment Criticality and Life-cycle Costing

Methodologies for assessing equipment criticality usually combine the probability and consequence of failure, and these have been used for the selection of materials and for defining product reliability requirements in subsea projects as described, for example, in the Energy Institute Publication 'Guidelines for the management of integrity of subsea facilities'. Criticality assessments for subsea equipment require particular care because many items will have high consequences of failure, and meaningful discrimination into different grades of criticality can be difficult to achieve. Also, it is necessary to consider all feasible 'failure' modes—not just those associated with loss of containment, but all those possible causes of loss of functionality or operability.

Subsea equipment design, materials selection, fabrication, testing and installation all require attention to detail of a higher level than that traditionally associated with topside/onshore facilities. Appropriate integrity assurance processes should therefore be applied through all these stages, e.g. independent design verification, qualification of new designs/materials/fabrication methods, procurement QA/QC, materials certification and traceability.

Life-cycle costing for materials selection is recommended, though its application is likely to be limited to relatively few equipment items where realistic options exist for both 'high' and 'low' capital expenditure. The most common example is inhibited carbon steel versus corrosion resistant alloy (CRA) for flowlines, where the field life operating costs for the inhibitor injection and the associated corrosion monitoring and pipeline condition assessment can usually be estimated fairly accurately. Strategic replacement of equipment during field life should also be considered.

Guidance on the application of life-cycle costing may be found in ISO 15663-1.

3.4 Carbon and Low Alloy Steels

Carbon and low alloy steels are extensively used in subsea equipment. As described in this Publication, restrictions on hardness for welded and non-welded components are required to prevent external hydrogen embrittlement from sacrificial anode cathodic protection.

Restrictions on yield strength for welded applications should also be considered. ISO 21457 and NORSOK M-001 both restrict the specified minimum yield strength (SMYS) of carbon and low alloy steels intended for welding to 560 MPa, but permit a higher SMYS, provided that documentation showing acceptable properties with respect to weldability and the properties of the base material, heat affected zone and weld metal is presented. It is recommended that information concerning the successful prior subsea application of specific higher strength steels should be sought as appropriate.

3.5 Applications of Corrosion Resistant Alloys

Table 2 (on page 12) provides a summary of the compositions, properties and application limits of the most commonly specified corrosion resistant alloys

(CRAs) for subsea use. The following general recommendations are made:

- Copper base alloys should not be specified for pressure boundary equipment in hazardous duty.
- Free-machining grades should be avoided due to their relatively poor corrosion resistance, even for small items machined from bar stock.
- Consideration should be given to qualification of alloys of 0.2% proof strength above 827 MPa (120 ksi) in terms of their mechanical, corrosion and environmental cracking performance.
- Low carbon grades of austenitic stainless steels, including 'dual grade' alloys such as 316 / 316L, are recommended for welded applications.
- Austenitic and super-austenitic alloys used for pressure boundary equipment should be specified to be in the solution treated and water quenched condition, and free from any cold work intended to enhance their mechanical properties. Forced air or gas quenching of thin-walled components may also be satisfactory, subject to qualification.
- Caution is advised on the use of cast 6Mo alloys for components to be welded due to segregation and risk of cracking.
- Duplex stainless steels should be specified and procured in accordance with EEMUA Publication 218 'Quality requirements for the manufacture and supply of duplex stainless steels'.
- Alloy 718 forgings should comply with API Specification 6A718.
- Alloy 625 weld overlays should have:
 - A minimum of two passes.
 - A thickness of at least 3 mm at the final finished surfaces, including machined locations.
 - An iron content at the finished surfaces not exceeding 10% for resistance to crevice corrosion (5% iron may be considered appropriate for severe sour service).
 - The chemical analysis confirmed at the predicted end-of-life thickness location, when internal erosion is expected.

3.6 The Process-side Environment

3.6.1 Introduction

The principles of materials selection for process-side environments are similar to those for surface designs, except that a more conservative approach can often be justified for the reasons stated. Key considerations for materials selection applicable to all types of subsea equipment include:

- material availability in the required product form;
- weldability;
- project cost and schedule requirements;
- complexity and novelty of manufacture and fabrication;
- damage mechanisms during storage and transport, deployment, wet parking, hydrotesting, and commissioning, particularly with regard to the potential for seawater ingress;
- damage mechanisms during operations, including startup, shutdown and well treatments; and
- predicted changes in reservoir conditions over the design life, e.g. souring.

3.6.2 H₂S-Containing Environments

3.6.2.1 Relevant Standards

Documents describing options for dealing with H₂S in the produced fluids include:

- ISO 15156/NACE MR0175 (the NACE MR is co-branded),
- NACE Report 1F192,
- EFC Publications 16 and 17,
- NACE TM0177, and
- NACE TM0284.

3.6.2.2 Sulphide Stress Cracking (SSC) Resistance of 13% Cr and Duplex/Superduplex Stainless Steels

For carbon or low-alloy steels, the cost impact of using 'sour-resistant' grades is usually minimal. Hence they are often specified for environments containing even low H₂S levels, i.e. below the thresholds for SSC as defined in the above documents. For CRAs with only limited 'sour resistance', however (e.g. weldable 13%Cr steels and duplex/superduplex stainless steels), the need to use a different alloy composition for sour service is likely to have a significant cost impact.

'Sour service' limits for the weldable 13%Cr and duplex/superduplex stainless steels are somewhat complex. Such materials would probably fail sour service testing in the 'standard' conditions used for carbon/low alloy steels (as defined in NACE TM0177 and associated documents). The susceptibility to SSC is a function of the temperature, H₂S level, pH and chloride content of the transported water.

H₂S limits for some grades of 13%Cr and duplex/superduplex stainless steels in specific process conditions are given in ISO 15156 / NACE MR0175, NACE Report 1F192 and NORSOK Standard M-001. Manufacturers of such grades might also recommend sour service limits, and many users have their own guidelines. Typical limits currently considered by some users to be acceptable for the avoidance of SSC are given in Appendix II.

The effects of operations such as welding and plastic straining (e.g. during pipe reeling) on SSC resistance need to be considered.

In cases of doubt, particularly for those materials with uncertain SSC resistance, 'sour service' materials testing of parent material and representative welds under the actual or predicted environmental conditions (or under a 'worst case' estimate of conditions) at a load close to yield should be made. A conservative approach to materials selection is recommended where conditions are considered marginal between different classes or grades of steels/alloys. Alternatives such as carbon steel clad or lined with a high alloy CRA (e.g. Alloy 625) should be considered.

Table 2 CRAs commonly used in subsea equipment

Generic Type	Common Name	UNS	Typical Composition				Typical Properties, MPa ¹		Typical Min Design Temp °C	PREN ² / PREw (min)
			Cr	Ni	Mo	Others	Min YS	Min TS		
Austenitic Stainless Steels	316L SS	S31603	18	12	2.5		205	515	−196	22.6
	Nitronic 50	S20910	20.5	12.5	2.25	Mn, Nb, N	380	690	−196	28.6
Super-austenitic Stainless Steels	6Mo	S31254	20	18	6	N	300	650	−196	42.2
	904L	N08904	21	25	4.5	Cu	220	490	−196	32.2
	Alloy (Sanicro) 28	N08028	27	31	3.5	Cu	215	550	−196	35.9
Precipitation-Hardened Aust. SS	Grade 660	S66286	15	25	1.25	Al,Ti,V,B	585	895	−29	16.8
Duplex Stainless Steels	Nitronic 19D	S32001	19.7	1.6	0.06	Mn, N, Cu	450	620	−50	22
	22% Cr Duplex	S31803	22	5.5	3	N	450	620	−50	30.5 ⁶
	25%Cr Superduplex	S32550	25	5.5	3	N	600	760	−50	32.2 ⁵
	25%Cr Superduplex	S32750	25	7	3.5	N	550	800	−46	37.7 ⁵
	25%Cr Superduplex	S32760	25	7	3.5	N,Cu,W	550	750	−46	37.4 ⁵
	25% Cr Superduplex	S32974	25	7	3.2	N,Cu,W	550	800	−46	36.7 ⁵
Martensitic Stainless Steels	410 SS	S41000	12.5	0	0		380	585	−10	11.5
	F6NM	S42400	13	4	0.5		620	790	−46	13
	Super-13%Cr (weldable)	Appx IV	11–13	2.5– 6	1– 3		500	600	(Note ³)	
Nickel Base Alloys	Alloy (Incoloy) 825	N08825	21	42	3	Cu,Ti	175	515	−196	27.8
	Alloy (Incoloy) 925	N09925	21	44	3	Cu,Ti,Al	810	1210	−196	27.8
	Alloy (Inconel) 625	N06625	22	60	9	Fe, Nb	415	825	−196	46.4
	Alloy (Inconel) 718	N07718	19	53	3	Fe,Al,Ti,Nb	1030	1275	−196	26.2
	Alloy (Inconel) X-750	N07750	16	75	0	Fe,Al,Ti,Nb	895	1275	−196	14
	Alloy (Inconel) 725	N07725	21	57	8	Fe,Al,Ti,Nb	895	1200	−196	42.1
	Alloy (Hastelloy) C-22	N06022	21	55	13.5	Fe,Co,W	310	690	−196	65.5
	Alloy (Hastelloy) C-276	N10276	16	55	16	Co,Fe,W,V	280	690	−196	64
	Alloy (Hastelloy) C-4	N06455	16	63	16	Co,Fe,Ti	275	690	−196	60.2
	Alloy (Monel) 400	N04400	0	66		Cu	195	480	−196	n/a
Cobalt Base Alloys	Elgiloy	R30003	20	16	7	Co	1510	2500	−196	n/a
	MP35N	R30035	20	35	10	Co	380–1950	900–2000	−196	n/a
Copper Base Alloys	Ni-Al-Bronze	C95800		4.5		Cu,Al,Fe	300	650	−196	n/a
	High Strength Cupronickel	C72420		15		Cu,Al,Fe,Mn	430	710	−196	n/a
Titanium Alloys	Grade 5 Ti-6Al-4V	R56400					830	895	−60 ⁴	n/a
	Grade 12 Ti-0.3Mo-0.8Ni	R53400					345	483	(Note ⁴)	n/a
	Grade 19, Beta-C	R58640					896–1170	965–1240	−60 ⁴	n/a
	Grade 23, Ti-6Al-4V ELI	R56407					758	827	(Note ⁴)	n/a
	Grade 29, Ti-6Al-4V-0.1Ru	R56404					758	827	(Note ⁴)	n/a

Table 2 Footnotes

- ¹ Dependent on heat treatment condition.
- ² $PREN = \%Cr + 3.3\%Mo + 16\%N$ (The other frequently used equation is for PREw which also accounts for presence of tungsten. $PREw = \%Cr + 3.3(Mo\% + 0.5W\%) + 16\%N$).
- ³ Typically from $-20^{\circ}C$ to $-46^{\circ}C$, dependent on grade.
- ⁴ From ANSI-ASME Codes. Good low temperature fracture toughness: dictated by design code.
- ⁵ Superduplex stainless steels are commonly specified to have a minimum PREN/PREw of 40 for general application, and 42 for umbilical tubing.
- ⁶ 22% Cr duplex stainless steels are commonly specified to have a minimum PREN/PREw of 35.
-

3.6.2.3 HIC-Resistance of Carbon and Low Alloy Steels

Recommendations to deal with hydrogen-induced cracking (HIC), stress oriented HIC (SOHIC) and stepwise cracking (SWC) are made in ISO 15156 Part 2 and EFC Publication 16, and need to be considered for **any** level of H_2S in the produced fluids. A test method for assessing the susceptibility of materials is NACE Standard TM0284 (HIC).

The probability of HIC can be minimised by steel chemistry control and by avoiding plate steels for fabricated items, e.g. valve bodies, longitudinally welded piping.

3.6.3 CO₂-Containing Environments

Documents providing guidance for the use of carbon and low alloy steels in wet CO₂ environments include EFC Publication 23 and NORSOK Standard M-506. Some users have generated their own predictive models for CO₂ corrosion that differ mainly in terms of the effects of protective scaling at elevated temperature, stream velocity, and algorithms for pH prediction. Effects of organic acids should be taken into account in corrosion prediction modelling and in any testing for corrosion inhibitor selection.

The main value of these documents and models will be for the prediction of CO₂ corrosion rates, and thereby the assessment of the viability of using carbon or low alloy steels for subsea equipment. The more conservative approach to subsea materials selection often results in higher alloy materials being selected.

The corrosion performance of the higher alloys in CO₂-containing environments should be considered in terms of both general corrosion or localised corrosion, especially in high temperatures and/or high salinity waters. Intergranular corrosion associated with sensitisation of the weld HAZ of 'lean' grades of weldable 13Cr alloys has also been observed (see Appendix IV).

3.6.4 Chloride Ion Environments

300-series austenitic stainless steels in the as-welded or cold worked condition are well known to be highly susceptible to chloride stress corrosion cracking (SCC) at metal temperatures above about 50°C. Due to their low strength

properties, these alloys find relatively little application for subsea pressure containment equipment other than for hydraulic control/chemical injection tubing (see Section 11.2.1).

Although duplex stainless steels have far superior resistance to chloride SCC, very high concentrations of chloride ions in combination with relatively high temperatures ($> 100^{\circ}\text{C}$) can lead to failures. Several such incidents in topsides process equipment have occurred, either due to internal or external induced cracking. The conditions under which cracking can occur are not well understood: a summary of the failures and current knowledge of this phenomenon can be found at the GB Health and Safety Executive website www.hse.gov.uk (search Research Report 129).

The internal failures were associated with water flashing downstream of control valves in the gas–condensate systems of HP/HT plant, allowing internal deposition of very corrosive high chloride solids. The process conditions that led to these failures are unlikely to be experienced subsea but should nevertheless be checked in HP/HT developments where duplex stainless steel is proposed for flowlines or manifold piping.

Where doubts about the suitability of duplex stainless steel in HP/HT environments exist, consideration should be given to more chloride SCC-resistant materials such as Alloy 825 or carbon steel internally clad with Alloy 625.

3.6.5 Erosion

3.6.5.1 General

Erosion can be defined as the wastage that occurs by mechanical removal of material from surfaces due to the impact of liquid droplets and/or solid particles. It will need to be considered for all production scenarios, but especially for equipment handling high velocity multiphase streams or when solids production is expected.

Guidance is available in a number of documents, including ISO 13703, API RP 14E and DNV RP-O501. Predictive models to evaluate erosion rates by solids (e.g. sand) have been developed in a number of joint-venture projects, including those run by the University of Tulsa's 'Erosion-Corrosion Research Center' and by AEA Technology. A predictive model has also been developed by DNV (RP-O501), whilst the GB Health and Safety Executive has published guidance on the avoidance of erosion of piping elbows on its website (Research Report 115 obtainable from www.hse.gov.uk).

3.6.5.2 Types of Erosion Damage

Erosion damage can be essentially categorised as four main types:

- i) Pure erosion by liquid droplet or gas bubble impact in a non-corrosive fluid.** In a multiphase flow regime, droplet impact is possible in annular mist flow (the corollary to this would be bubble impact in bubbly flow, although this is significantly less damaging) and can result in the mechanical removal of material (i.e. erosion). In practice, droplet erosion is generally only a problem in multiphase systems with high mixture velocities. For gas–condensate systems DNV RP-O501 recommends a

maximum velocity of 70 to 80 m/s. Another approach to derive maximum allowable velocities is that of API RP 14E, using company-specific 'C' constants derived by testing and/or experience.

ii) Pure erosion by solid particle impact in a non-corrosive fluid. This mechanism could apply to very low corrosivity or dry gas, gas-condensate or oil systems where corrosion is not a problem. Production rate is highly relevant here because, typically, doubling the production rate will result in an order-of-magnitude increase in erosion rate. Sand content and erosion rate, however, are generally in direct proportion, except for very high sand contents when energy losses occur due to inter-particle collision.

iii) Erosion-corrosion by a corrosive fluid in the absence of solids. Most oil and/or gas production systems will exhibit some corrosivity. In the absence of solids, enhanced erosion-corrosion wastage can occur due to the removal of protective corrosion product layers or corrosion inhibitor films by the fluid flow, with consequent corrosion of the newly exposed surface.

iv) Erosion-corrosion by a corrosive fluid containing solids. In solids-containing fluids, there can be synergy between the erosion and corrosion rates, e.g. due to the removal of protective corrosion scales or inhibitor films, such that the resultant damage can be significantly enhanced. However, as a rule of thumb, if the expected erosion rate is an order of magnitude less than the expected corrosion rate, or vice versa, then synergistic effects between them are likely to be minor.

3.6.5.3 Likely Locations and Nature of Erosion

Guidelines for identifying the likelihood, locations and nature of erosion are set out below.

- In the absence of solids, erosion is unlikely to be a problem unless flow rates are very high. Wastage is most likely to be corrosion dominated.
- Solids erosion is by far the most aggressive damage mechanism. Severe erosion problems are therefore most likely to be associated with entrained solids.
- Erosion is most likely to occur at changes in flow direction, e.g. bends, tees, at or downstream of constrictions or valves (especially chokes).
- Eroded surfaces will generally be shiny and relatively free from deposits. They also appear relatively smooth, due to the polishing effect of the erosion damage.
- Where erosion pits are formed, they exhibit a characteristic sharp-edged appearance, either as a tear-drop shape (with the narrow end upstream) or as a horseshoe shape.

3.6.5.4 Alleviating Damage by Erosion

Possible methods for alleviating the effects of damage by erosion include:

- Designing out erosion by removing the solids (downhole sand screens, gravel packs, in-line sand removal equipment, etc.), reducing the flow velocity (e.g. by increasing pipe diameter, using 'dual' lines), giving close attention to manifold piping design, eliminating sharp bends, using target

tees (NB: not universally effective and not normally beneficial for liquid systems, only really useful for gas systems and the like) and erosion-resistant valve designs. API RP 14E, ISO 13703 and DNV RP-O501 give further guidance on some of these aspects.

- Using erosion-resistant materials for solid-particle containing conditions. Carbon steels, stainless steels and nickel-base CRAs are often not suitable for duties where erosion by solid particles is a problem. Suitable materials are often very hard e.g. proprietary cobalt-base alloys, tungsten carbide or ceramics, but are not a universal panacea: even those materials will experience erosion under severe conditions. Alternatively, very soft elastomeric coatings or liners are possible options, but it needs to be demonstrated that they are resistant to the production fluids and operating temperatures. As yet, there is no extensive experience with non-metallic materials in such service.
- For nominally solids-free production (less than one pound of solids per thousand barrels of liquid (1 pptb) for liquid flow, or 0.1 lb of solids per MMscf (millions of standard cubic feet) of gas for gaseous flow, consider the use of erosion-corrosion resistant materials. The higher alloy CRAs are generally more erosion-corrosion resistant than carbon steel or 13Cr steel as they do not suffer from the same levels of synergistic erosion-corrosion. However, care should be taken when selecting CRAs for erosion-corrosion resistance, accelerated corrosion rates could occur for CRAs if the passive film is removed by solids erosion and the environment does not enable the passive layer to rapidly reform.
- When internal CRA cladding is specified, erosion studies should be made to demonstrate that adequate CRA thickness, typically at least 1 mm, will remain for the design life of the component.

3.6.5.5 Use of 'C-Factors'

Recently there has been a move away from the use of the API RP 14E equation together with the material- or application-specific C-factors, due to the fact that this methodology does not account for many of the major factors that affect erosion, such as fluid viscosity, solid particle size and concentration, flow regime, etc. In addition, the method can prove either overly conservative (for liquid flow) or non-conservative (for gas flow) if C-factors are selected to try to cover the full range of mixture densities. However, the API RP 14E approach can provide a useful 'order of magnitude' evaluation tool for totally solids-free or nominally solids-free conditions as long as the severe limitations in its use are realised and appropriate C-factors are generated for the materials/fluids/conditions under consideration.

The 'C-factor' constants recorded in API RP 14E are generally considered to be somewhat conservative, both for carbon steel and for CRAs, and higher values are utilised by many designers/users. Typical values which have been used for nominally solids-free or totally solids-free conditions, derived from both laboratory testing and field experience, are:

- carbon or low-alloy steel - 135 (gas or multiphase) or 250 (liquid only);
- 13Cr stainless steels - 300 (gas, multiphase or liquid); and

- CRAs (i.e. super-austenitic stainless steels, duplex stainless steels, nickel alloys) - 350 (gas or multiphase) or 450 (liquid only).

For absolutely solids free, single-phase gas conditions no erosional velocity limit is imposed.

3.6.6 Chemical Treatment and Deployment

Chemical treatments are frequently adopted for flow assurance and/or the control of corrosion or scaling in subsea producing systems, e.g.:

- corrosion inhibition/pH modifiers,
- scale inhibition,
- hydrate inhibition,
- wax control,
- asphaltine control,
- flow improvers.

Earliest consideration should be given in system design to the range of expected chemical treatments, understanding how the required chemicals will interact with the materials they contact (metals and elastomers) and how they will behave with one another when mixed.

The compatibility between treatment chemicals should be established before their final selection and use, since any potential incompatibility may result in neutralisation of one (or more) of the products' active ingredients, or in precipitation and blockage ('gunking').

If the range of chemicals or their compatibility with each other is not known at the design stage, installation of dedicated injection facilities for each chemical type is advised. The use of shared distribution and injection facilities is not recommended unless mixing and compatibility trials on the designated chemicals demonstrate no adverse interaction or precipitation. (See also Chapter 12 for recommendations for transport of chemicals by umbilicals).

The rheology of the chemicals at ambient temperature and seabed pressure and temperature needs to be understood when designing the pumping, delivery and distribution systems. Required flow rates, including chemical suppliers' minimum advised rates, need to be considered when sizing umbilical cores and specifying pumps. Distribution, injection facilities and flow measurement devices need to cater for any rheological changes between the point of supply and injection.

Suitable redundancy in the supply system may be necessary in order to achieve required chemical availability.

3.6.7 Mercury

Mercury and associated mercury compounds can be detrimental to certain materials. Mercury can occur naturally as a contaminant in well production fluids. The likelihood of its presence should be recognised at the earliest possible stage of design to avoid potentially susceptible materials being specified.

It is generally accepted that mercury needs to be present in the liquid form for

damage to occur. Attack can be by amalgamation or by liquid metal embrittlement (LME).

Alloys 400 and K500 fail by LME as a result of mercury adsorption onto their surface. Type 304 and 304L austenitic stainless steels and Alloy 600 have also been shown to be susceptible to LME when subjected to high loads and plastic strain, whilst austenitic stainless steel types 321, 316 and 316L appear to be unaffected in the same way.

Whilst unalloyed titanium is considered immune to damage by mercury, it is known that aluminium and copper alloys are affected. Caution should therefore be exercised if titanium alloys containing aluminium and/or copper are proposed for duty in systems that may contain mercury. Testing of these alloys to establish immunity or susceptibility is advised.

3.6.8 Preferential Weld Corrosion

Preferential weld corrosion (PWC) is the dissolution of metal associated with welds. It is a selective form of attack that corrodes the weld metal and/or heat affected weld zones rather than adjacent parent material. PWC rates of attack in carbon steel can be high: up to 12 mm/year have been observed in the laboratory and in the field. Since it is a selective form of attack, PWC should not be mitigated by additional design corrosion allowances, particularly for piping and flowlines.

PWC is a particular concern with carbon and low alloy steels used for transporting produced hydrocarbons with entrained water and CO₂ that have been welded with consumables depositing around 1% Ni weld metal. Preferential corrosion of welds containing increased levels of Si, or alloyed with Cr or Mo, can also be expected, although the effect may be less pronounced. Service experience indicates that gas and gas-condensate production systems are more prone to PWC damage than oil systems, and also that Ni-containing weld metal is beneficial for water injection lines.

Guidelines have been developed to reduce the risk of PWC in carbon and low alloy steels, including the selection and deployment of inhibitors. These guidelines are included in EFC Publication 39.

3.6.9 Other Considerations

Key additional considerations for materials selection include:

- Internal corrosion at locations of low flow where deposits might form and where corrosion inhibitors and biocides are unlikely to be effective.
- Internal corrosion due to water drop-out at low points.
- Localised pitting or general corrosion in CRAs at elevated temperatures (especially for 13% Cr and duplex/superduplex stainless steels).
- Corrosivity of internal fluids encountered during installation and operational transients (e.g. workovers), including chemical treatments and sea water entry.
- The effects of gas lift operations on corrosion.
- Specification and reliability of facilities for the treatment of reservoir injection fluids e.g. gas dehydration, water treatment, or for other applications e.g. flowline bundle heating.

- Materials availability, ease of fabrication and track record in the intended application.

3.7 The Seawater-side Environment

Most metallic materials for subsea use require a combination of protective coatings and cathodic protection (CP) to avoid general or localised seawater corrosion, and, in some cases, chloride ion SCC. Materials that can be considered, for design purposes, to be inherently resistant to corrosion in seawater (although even this resistance is only retained up to certain temperature limits) are Alloy 625 and other nickel-base alloys of equal or higher pitting resistance equivalent number (PREN/PREw), or titanium.

For optimum corrosion resistance, duplex stainless steels and most austenitic stainless steels and nickel alloys should be used in the solution treated and water quenched condition with microstructures confirmed free from undesirable precipitates (e.g. carbides, sigma phase), taking account of the effects of welding or other fabrication procedures. However, some grades of austenitic stainless steels and nickel alloys are used in the precipitation hardened condition, e.g. UNS S66286 and N07718.

Certain grades of austenitic stainless steels such as UNS S21800 have been formulated primarily for wear and galling resistance as opposed to corrosion resistance, and have particularly low PREN values. They are sometimes offered in the cold worked condition for enhanced strength, e.g. for hydraulic couplers, and may even receive a heat treatment that results in sensitisation. Failures by pitting and stress corrosion cracking have been reported on items manufactured in these types of alloys due to exposure to non-submerged marine environments prior to deployment.

External chloride SCC of duplex stainless steels due to the concentration of chlorides on unprotected high temperature surfaces is generally unlikely to be a problem on painted or insulated subsea components additionally protected by CP. Nevertheless a theoretical risk will exist for HP/HT installations, e.g. at crevices, and so a detailed risk assessment should be made where duplex stainless steels are proposed for such developments.

The corrosivity of the sea water and/or mud at the seabed will depend on factors such as oxygen content, bacterial activity, temperature, currents and salinity. These factors will normally only affect the design of the CP system and the selection of protective coatings, and not materials selection as such.

Materials for raw seawater injection schemes need to be designed in seawater resistant materials and/or using carbon steel with robust internal protective coatings or linings. External CP is not effective in controlling internal corrosion. Avoidance of external hydrogen embrittlement of carbon or low alloy steels and CRAs induced by CP systems will represent an important part of materials selection and specification, and is discussed in detail in the equipment-specific sections and appendices of this Publication.

Occasionally, it is necessary to specify materials with inherent resistance to marine fouling, e.g. for exposed valve stems that could damage stem seals or packing during operation. Copper-base alloys are particularly suitable, and

various high strength versions are available including the precipitation treated cupro-nickels and beryllium-copper alloys.

For raw seawater handling equipment, superduplex stainless steels (PREN/PRE_w > 40), some super-austenitic stainless steels and some copper-base alloys have good resistance to internal corrosion for restricted (i.e. lower) operating temperatures. Care is required with chlorine or hypochlorite injection in raw seawater injection schemes as this can greatly increase the water corrosivity, further restricting the operating temperatures for these materials.

3.8 Hydrotesting and Commissioning Environments

Care is required in the specification and control of hydrotesting media and any other transient environments in order to avoid internal corrosion and fouling. Many grades of stainless steel used for internal components will not be resistant to localised pitting and crevice corrosion in raw seawater, refer to Figure 1.

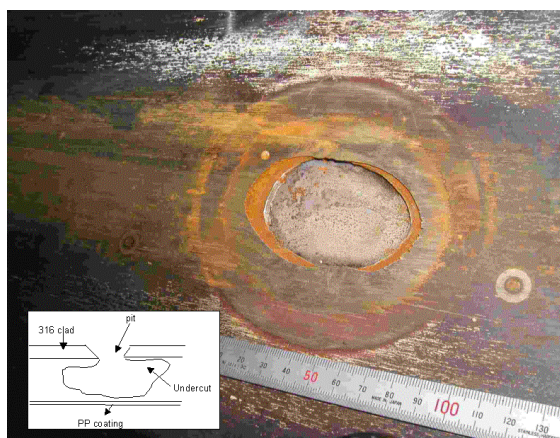


Figure 1 Severe internal corrosion of a 316 SS-clad subsea pipeline caused by excessive exposure time to seawater hydrotest fluid

Chemical treatment of hydrotest seawater is required using corrosion inhibitors, biocides and oxygen scavengers. The use of fresh water is preferred, but is often difficult or impractical. Some assemblies such as manifolds can be deployed after filling with treated fluids, e.g. glycol-based control fluids of the type described in Section 11.2.1.

In all cases attention should be paid to adequate venting to minimise the volume of trapped air since this will promote corrosion. The overall time of exposure to these 'transient' fluids prior to commissioning should be minimised.

4. Cathodic Protection

4.1 Introduction

Subsea installations require corrosion protection, usually by external coatings in conjunction with a sacrificial anode CP system. A well designed and installed CP system will normally protect against all the following forms of external attack:

- general corrosion of carbon and low alloy steels;
- crevice corrosion, e.g. at screwed and flanged connections (flange protectors are not necessary and are not recommended);
- galvanic corrosion at the junctions of dissimilar metals;
- chloride ion SCC of austenitic stainless steels;
- pitting corrosion of stainless steels; and
- bacterial corrosion.

The protective coating reduces the amount of sacrificial anode material required to protect the structure, and enhances the uniformity of the spread of protection.

4.2 Conventional Sacrificial Anode Designs

4.2.1 Existing Practice

CP designs for structures or pipelines immersed in seawater have usually followed either DNV RP-B401 or NACE RP0176. For the North Sea and Norwegian Sea the NORSOK Standard M-503 has also been applied. ISO 15589-2 is now the recommended cathodic protection standard for carbon and stainless steel subsea pipelines, and is also applicable to retrofits, modifications and repairs made to existing pipeline systems.

These practices are based upon the premise that effective long term CP is reliant upon the build-up and maintenance of calcareous deposits upon the structure being protected. Specific current density requirements at three distinct stages in the structure's life—initial, mean and final—are identified and used to derive an appropriate CP design. High initial current densities are required to promote the rapid formation of the calcareous deposits and minimise the mean current density requirements thereafter. In the case of sacrificial anode systems, it is the mean current density that determines the overall anode weight. Minimising the mean current density requirement limits the additional weight of the anode system on the structure.

The 'final' current density takes into account the additional current density required to re-polarise the structure if the effectiveness of the established calcareous deposits and fouling layers is reduced during storms. The DNV RP gives guidance on these three current density requirements with respect to climatic region, while the NACE RP assigns values to specific coastal, country or sea locations. Neither document makes specific reference to deep water, yet the industry consensus is that the guidelines are applicable to water depths down to 300 m.

Subsea equipment is usually constructed from many different materials which are not resistant to seawater corrosion and which depend upon CP for their integrity. While it is not necessary for CRAs to be polarised to the same negative potentials as carbon steel, it is normally impractical to electrically isolate them from the

main steel structure. In fact it is necessary to ensure that all metallic components are electrically continuous. Typical practices include the use of continuity straps, fan disc washers beneath bolt heads, the removal of paint from contact surfaces, and welding. Electrical continuity checks are necessary for practically all components that are not connected directly to the main structure by welding. The maximum recommended resistance is 0.1 ohm. Particular attention should be paid to items which, by their design, are either 'loose' or are required to move, e.g. ROV-operated valve stem extensions. Figures 2 and 3 illustrate the consequences of failing to ensure electrical continuity. Severe corrosion has developed due to lack of electrical continuity with the associated structure and consequently no cathodic protection. PTFE coated fasteners are not recommended for this reason, as also explained in Section 9.2.2.4. In Figure 3 there was lack of electrical continuity with the cathodic protection system due to non-removal of paint beneath fasteners.



Figure 2 PTFE coated subsea fastener

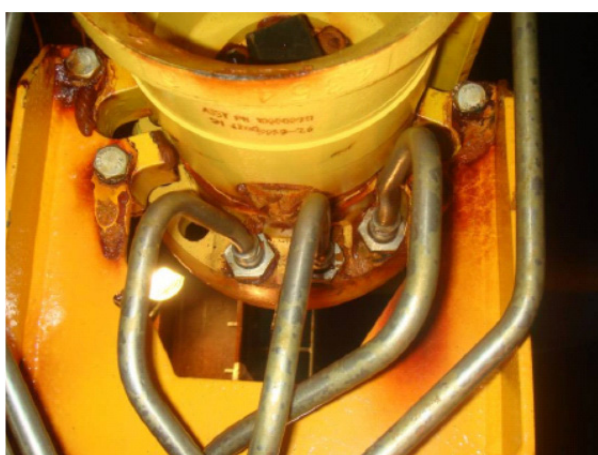


Figure 3 Umbilical connection head showing severe corrosion of the carbon steel components

The phenomenon of hydrogen generation on cathodically protected structures is well understood. The rate of reduction of hydrogen ions to atomic hydrogen at the surface of a metal increases logarithmically with a linear negative change at potentials below -800 mV versus Ag/AgCl/seawater. While there is a tendency

for hydrogen atoms to combine to form hydrogen gas, the reaction is slow and the atoms have time to diffuse into the metal. The presence of H_2S , due to microbial activity, further promotes hydrogen charging.

Charging can induce hydrogen embrittlement (HE) in many high strength steels, stainless steels and non-ferrous alloys (e.g. nickel alloys). Factors that usually determine the likelihood of HE and cracking taking place are:

- The material's microstructure and hardness.
- Applied and residual stresses, and whether these are static or dynamic.
- Excessively negative potentials.

Cracking has occurred with many different materials including high strength steels (>700 MPa yield strength), Alloy K500 polarised to potentials more negative than -900 mV, and both duplex and superduplex stainless steels polarised to about -1000 mV. While HE of titanium due to galvanic coupling with a less noble metal is a well-known phenomenon, there have been no reports of titanium alloys suffering HE subsea.

4.2.2 Deep Water Sacrificial Anode CP Design

Seawater environments change with depth, geographical location and season in a way that can have a significant effect on current density requirements for CP. Oxygen solubility is usually less than in shallower waters, but remains significant; temperatures are lower, fouling is less, seawater velocity, salinity and pH are variable. In some deep water locations of the world the oxygen content and velocity of the water at the seabed can be surprisingly high due to descending cold polar currents.

Perhaps most importantly, the solubility of calcium carbonate is higher in deep water. Calcareous deposits do not form as readily, nor are they as persistent as in shallow waters. The analysis of seawater properties for the determination of CP current density requirements has proved to be virtually impossible, and so, to date, these requirements for deep water structures have been mainly developed by empirical means, using test assemblies deployed at the specific water depths of interest. On some occasions, retrospective data have been collected using CP monitoring systems installed on a deep water platform or installation.

Measurements have confirmed that initial current densities required for the effective polarisation of bare steel in deeper waters are often 1.5 to 2 times those recommended for shallower waters. The two most influential aspects are the poorer quality of the calcareous deposits and the increased hydrostatic pressure. Poor quality calcareous deposits mean that the metal surface is more accessible, and more hydrogen can be generated. The kinetics of the hydrogen ion reduction reaction itself are not directly affected by changes in pressure, but the subsequent combining of hydrogen atoms to produce hydrogen gas, which competes with the entry of atomic hydrogen into the metal, will be retarded. Opportunities for hydrogen diffusion into the metal would appear to be greater in deep water, though whether this increases the susceptibility of materials to HE *per se* is not clear. Some users take the view it does not, hence they do not distinguish between deep water and shallow water in defining maximum limits for material strengths and hardnesses.

Laboratory studies have shown that increases in the corrosion rate of carbon steel

with increasing hydrostatic pressure can be ascribed to the effect of pressure upon the kinetics of the oxygen reduction reaction. The kinetics of the iron dissolution reaction is not affected, and thus the electrical potential at which iron is immune from corrosion in seawater is the same regardless of water depth. It follows that the same potential criteria for the protection of carbon steel in shallow waters (–800 mV versus Ag/AgCl/seawater in aerobic conditions, –900 mV in anaerobic conditions) are also applicable in deep water. In the absence of any definitive knowledge regarding the effect of water depth upon the growth of sulphate reducing bacteria (SRB), it would be appear prudent at present to adopt the same approach to the risk of SRB proliferation on the seabed or beneath fouling deposits.

There is a dilemma associated with the use of CRAs connected to carbon steel in adequately protecting the latter from general corrosion without inducing HE in the former. The following are seen as key areas in the quest for the level of equipment reliability which deep water exploitation demands (see also Appendices III and IV):

- The use of component designs which are simple in relative terms and avoid the need for complex geometries as far as possible in order to ensure uniformity of CP.
- The adoption of low maximum allowable global stresses, well below the specified minimum yield stress, and minimisation of stress concentrations (e.g. due to poor fit-up, doubler plates, sharp changes in section, etc.).
- Assurance that materials are supplied with optimum heat treatment and microstructure.
- The more widespread use of durable, highly insulating protective coatings on CRAs and high strength steels to minimise hydrogen entry.
- Guidelines on the design current densities to be used on deep water structures to avoid the application of unnecessarily high current densities. *(Note: in practice, cathode potentials during early operating life will be close to open circuit anode potentials due to the general adoption of high quality coatings. Therefore, reductions in design current density alone may not result in significantly lowered risk of HE damage.)*
- Assurance that interaction between sacrificial anode CP systems for subsea equipment and impressed current CP systems for FPSOs or other surface facilities does not result in overprotection, increasing the risk of HE.
- Further investigations into the use of low voltage CP using diodes or alternative anode compositions.

Further guidance is provided in NACE Report 7L192.

4.3 Low Voltage Cathodic Protection

4.3.1 Introduction

The relationship between the quantity of hydrogen ions electrochemically reduced to hydrogen atoms at the metal surface and the electrochemical potential is logarithmic: for a unit change in potential there is a tenfold change in the rate of reduction. Limiting the generation of atomic hydrogen at the metal surface by controlling the applied CP potential represents, arguably, the most effective method of minimising HE risks.

The most negative potentials that can be achieved using 'state of the art'

sacrificial anodes are governed by the open circuit potentials of the anodes themselves, typically a value of -1050 mV for zinc and -1100 mV for aluminium–zinc–indium. Potentials more negative than -900 mV versus Ag/AgCl/seawater are sufficient to cause embrittlement and crack propagation where the mechanical properties, applied loading conditions and/or microstructure lead to susceptibility to cracking. At potentials less negative than -800 mV the rate of the hydrogen reduction reaction and likelihood of HE cracking become negligible.

4.3.2 Diode Control

The current output of sacrificial anodes and, correspondingly, the potential of the structure, can be controlled using Schottky diodes that only allow current to pass when the voltage across the diode exceeds a certain limit. In the case of aluminium anodes and a controlled negative potential limit on the structure of -800 mV, this potential limit is 300 mV. Once the potential difference between the anode and the structure falls below this level, the Schottky diode becomes open circuit and current no longer flows between the anodes and the structure until the 300 mV difference is restored. For successful control of the potential of the entire structure at risk from HE, every anode needs to be connected to the structure via a Schottky diode. The structure needs to be electrically isolated from adjacent structures with conventional CP systems, otherwise the CP system on the adjacent structure will override the control being imposed by the diodes. The establishment of permanent electrical isolation is often difficult offshore, particularly on complex subsea facilities, in which case the use of diode controlled CP systems should be avoided.

Nevertheless, there have been several instances of the use of Schottky diode-controlled sacrificial anode CP systems to minimise the risk of HE of high strength steels, such as on simple pipeline systems or isolated steel structures. Reports indicate that in conjunction with protective coatings, dioded anodes have performed much as intended. On one bare structure a reluctance to achieve full polarisation has been reported, indicating that there is still much to be learnt about how these systems perform where high current demands are required.

Dioded anode designs should be qualified by testing to demonstrate their reliability under the intended operating conditions, particularly the design hydrostatic pressure for deep water.

4.3.3 Low Voltage Anodes

As an alternative to controlling the potential of conventional sacrificial anodes using diodes, work by the French navy has aimed at developing a commercial low voltage anode composition based upon aluminium. Initial studies indicated that an Al–0.1% Ga alloy, with an operating potential of -840 to -880 mV versus Ag/AgCl/seawater, is feasible. The composition of this alloy is patented. The same considerations about the need to isolate the structure from adjacent conventionally protected structures would apply. There is little operating experience with these anodes under conditions likely to be encountered, such as high hydrostatic pressure, burial in marine sediments, or higher operating temperatures, and further research or qualification testing should be considered before selection of this option.

Carbon steel/iron anodes can be used to protect some CRAs, and this method has a history in seawater coolers. Whilst the adoption of such anodes would seem an

attractive proposition, the lack of operational experience and field proven design data (particularly in deep water conditions) would indicate that further research and qualification testing would be required.

4.3.4 Implications of Low Voltage CP

There are three significant implications of using low voltage CP to prevent both corrosion and HE of materials subsea which need to be borne in mind:

- **The formation of calcareous deposits.** Conventional CP designs for offshore structures are based upon the assumption of different current density requirements at different stages of the structure's life, and a high current density is desirable at the beginning to enable calcareous deposits to form rapidly. A major consequence of using potential-limiting or low voltage anodes is that, compared with a conventional sacrificial anode CP system, the actual current flowing to the structure is restricted, and calcareous deposit formation will occur at a slower rate. This has a fundamental impact upon CP design that, although not critical for coated structures, requires a reappraisal of the existing design rules where uncoated structures are concerned.
- **Sulphate reducing bacteria.** It is widely acknowledged that where there is a risk of SRB being active, the normally applied CP criterion in sea water of -800 mV versus Ag/AgCl/seawater for carbon steels needs to be adjusted to -900 mV. Such a move to more negative potentials is clearly in conflict with the need to limit CP potentials to prevent HE. Once again, this issue is likely to be more relevant on a bare structure than on one that is additionally protected from corrosion by a heavy-duty coating.
- **The effect upon crevice corrosion.** It is generally acknowledged that in seawater the spread of CP down crevices, such as those at bolted flanges, is sufficient to prevent crevice corrosion, providing that there is effective CP outside the crevice. The term 'effective CP' may be interpreted as measured potentials of typically -900 mV versus Ag/AgCl/seawater outside the crevice. With potentials limited to about -800 mV outside the crevice, there will be a higher risk of crevice corrosion, particularly where the crevice is formed between dissimilar metals.

4.4 Anode Material Specifications

Conventional aluminium–zinc–indium alloy anodes can have widely varying composition, particularly with respect to zinc, indium, iron and silicon contents, whilst still meeting the manufacturer's defined alloy specification. There is evidence that anodes may not perform satisfactorily across the widest conventional compositional range, particularly in deep water applications, or in hot operating conditions such as can occur on buried flow-lines. An optimised compositional range and performance requirements should be specified, based on proven satisfactory performance history under equivalent conditions, or on results of qualification testing under appropriate conditions.

Whilst there is still little documented deep water data available relating to long term anode performance, there are indications that lower electrochemical capacity values may apply for anodes particularly in deep water, and when operated at low anodic current densities typical for well-coated pipelines or

subsea equipment. Conservative design capacity values should be selected in the absence of long-term service or qualification data under similar conditions. Figure 4 shows the condition of a subsea unit that had to be recovered after about ten years subsea due to an electrical fault, which provided a rare opportunity to assess in detail the performance of the CP anodes



Figure 4 Subsea umbilical termination unit recovered after 10 years subsea, showing extensive wastage of the aluminium anodes but no corrosion of the steel structure

5. Wellheads and Trees

5.1 Introduction

Wellhead and tree equipment can be used for hydrocarbon production, sea water injection (raw and treated), and a variety of chemicals for well treatment and gas lift operations. There may be a need for a change in the duty of a subsea tree during its lifetime, e.g. from production to injection, and this should be carefully considered at the design stage in order to ensure that the materials specified have the required properties and corrosion resistance.

Although valves and bolting form part of this equipment, they are separately dealt with in Chapters 8 and 9 of this document.

Typical subsea tree assemblies are shown in Figure 5.



Figure 5 Typical subsea tree assemblies

5.2 Relevant Standards

Relevant standards are ISO 10423 (API Spec 6A) and ISO 13628-4 (API Spec 17D).

5.3 Major Components in Wellhead Equipment

The major components in wellhead equipment as shown in Figure 6 overleaf excluding bolting, are:

- tree connector,
- tree body,
- wellhead housing,
- casing hanger,
- tubing hanger,
- seal assemblies,
- valves and chokes, and
- flow spools.

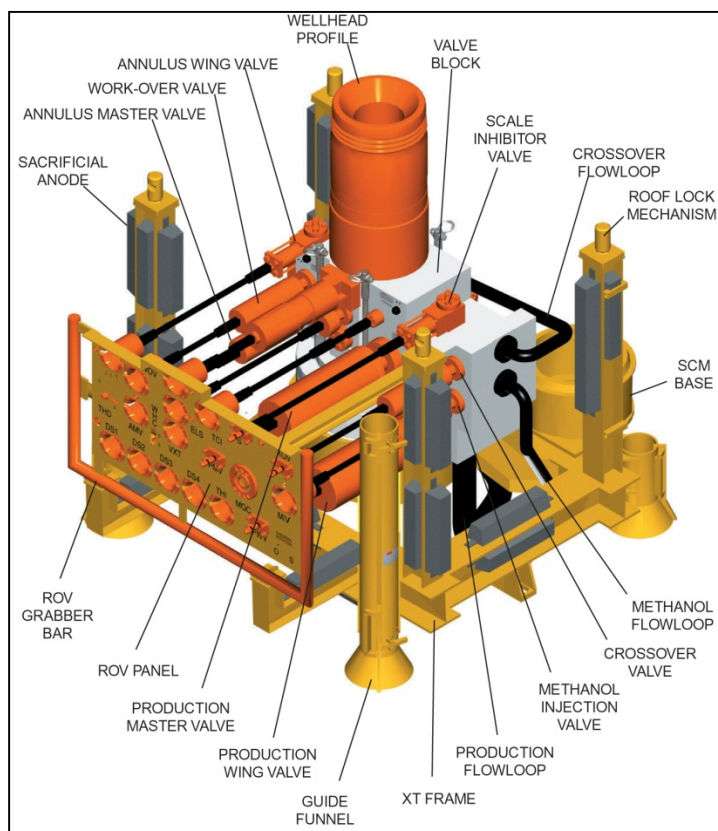


Figure 6 Typical subsea tree components

5.4 Material Considerations

The items listed in Section 5.3 are critical components, and careful consideration should be given to the specification of materials. It is recommended that all process-wetted materials other than bolting meet the requirements of ISO 15156/ NACE MR0175.

The ISO/API Product Specification Level (PSL) for subsea wellhead and tree equipment is typically 3, though ISO 13628-4 permits either PSL 2 or 3. The Temperature Classification is typically 'U', relating to an operating range of -18°C to 121°C . It should be noted that API Spec 17D requires all PSL 3 equipment to be impact tested regardless of temperature rating, the requirement being a minimum average of 20 J in the transverse direction at -18°C .

For subsea applications, PSL 3 with a gas test, in addition to the hydrostatic test, is recommended. This is referred to as PSL 3G.

Wellhead equipment should be corrosion resistant to the production and injection fluids in all internally process-wetted areas since, due to the complex geometry and turbulent flow, corrosion inhibition cannot be relied upon to protect carbon and low alloy steels. It is also very unlikely that protective scales will form at the high velocities experienced in the trees, especially with chemicals being injected downhole.

Materials in direct contact with production fluids can be either inherently corrosion resistant or weld overlaid with a CRA.

Other material considerations are erosion, particularly if sand is produced, and the relatively large section thickness of many of the subsea components that will affect heat treatments and the attainment of suitable microstructures and mechanical properties. Preference should be given to the use of forged products for all high integrity components.

There are many 'minor' components, e.g. control line connectors, which if not correctly specified can lead to failure or malfunction of the equipment. It is therefore recommended that the materials properties and corrosion resistance of all components be considered.

5.5 Material Options

5.5.1 Tree Body and Connector

Forged trees and connectors have been produced successfully in a number of materials:

- Low alloy steel, AISI 4130 and 8630, internally overlaid with a suitable CRA, e.g. Alloy 625.
- ASTM A182 F22 (2¼%Cr 1%Mo steel), overlaid with a suitable CRA, e.g. Alloy 625.
- AISI 410 (13%Cr stainless steel).
- ASTM A182 F6NM (13%Cr 4%Ni stainless steel).
- Duplex stainless steel.

It is unlikely that low alloy steel without weld overlay would be acceptable except in the most benign and short service conditions, or for treated sea water injection. Even in those conditions, seat pockets and seal areas should be overlaid with Alloy 625 in accordance with Section 3.5, and trim should be in a suitable grade of stainless steel.

Although AISI 410 and A182 F6NM may have adequate corrosion resistance for many applications, consideration should be given to achieving the required impact toughness in thick section components, and to weldability. F6NM has higher toughness and superior weldability to type 410 stainless steel. Welds in type 410 stainless steel can have relatively poor toughness, even after PWHT.

Duplex stainless steel is not recommended for subsea tree bodies due to the danger of the formation of detrimental tertiary phases in thick section forgings, with resultant deterioration of corrosion resistance and toughness.

Of the above listed materials, low alloy steel weld overlaid with a suitable CRA, e.g. Alloy 625, represents the lowest risk option for subsea. The preferred low alloy steel is ASTM A182 F22, since this provides better through thickness hardenability in thick section forgings, and is especially recommended for pressure ratings above 689 bar (10,000 psi).

Note: The designer should be aware that the mechanical properties determined for large section forgings on a qualification test coupon in accordance with API Specification 6A might only represent the near surface mechanical properties and not the bulk properties. If bulk section properties are required for design purposes, they should be measured at an appropriate depth into the forging section on a representative prolongation.

5.5.2 Wellhead Housing, Casing Hanger and Seal Assemblies

These are of thinner section than the tree bodies, and can be manufactured in AISI 4130 or 8630. Any process-wetted areas and/or seal areas should be overlaid with a suitable CRA, e.g. Alloy 625.

5.5.3 Casing Hangers

Casing hangers are usually manufactured in AISI 4130, 4140 or 8630, and under normal operating conditions do not come into contact with produced fluids.

5.5.4 Tubing Hangers

Tubing hangers should be manufactured from high strength CRA materials. Depending on the service, acceptable materials are:

- AISI 4130, 8630 or ASTM A182 F22 weld overlaid with a suitable CRA, e.g. Alloy 625 in all wetted areas.
Note: the designer should be aware of the tendency for the formation of hard zones in the fusion boundary between low alloy steels and Alloy 625 (refer to Section 6.6).
- ASTM A182 F6NM.
- 22% or 25% chromium duplex stainless steel.
- Alloy 718 supplied in accordance with API Spec 6A718.

5.5.5 Valves and Chokes

The body and bonnets of valves and chokes are usually manufactured in either:

- AISI 4130 or 8630, with any process-wetted surfaces and seal areas being weld overlaid with a suitable CRA, e.g. Alloy 625, and
- ASTM A182 F6NM.

Stems are typically in high strength CRA materials such as Alloy 718 hard faced with tungsten carbide. Gates are usually manufactured from ASTM A182 F6NM, AISI 4130 or AISI 8630 material and also hard faced: see Chapter 8.

5.5.6 Gaskets

Gasket materials in subsea hydrocarbon service may be manufactured in type 316 stainless steel, but Alloys 825 or 625 in the annealed condition are preferred for greater corrosion resistance. Where gaskets are to be used in ring grooves overlaid with Alloy 625, it is recommended that Alloy 625 or 6% molybdenum stainless steel gaskets in the annealed condition be used. For treated sea water injection, a 6% molybdenum stainless steel in the annealed condition is acceptable. For raw seawater injection, careful consideration needs to be given to ensuring adequate crevice and galvanic corrosion resistance of materials at the expected operating temperature.

5.5.7 Hydraulic Tubing

Solution annealed AISI 316 or if welded, 316L, stainless steel is commonly used, but for higher pressure and higher temperature applications Alloy 825 and Alloy

625 are recommended. Alloy 400 is also suitable provided it is not exposed to production fluids containing mercury. See also Chapter 11.

5.5.8 Flow Spools

Flow spools are usually manufactured from a CRA such as 22% or 25% chromium duplex stainless steel, with induction bends in the solution annealed condition (full component solution heat treatment and water quench). Carbon steel internally weld overlaid with Alloy 625 or higher grade austenitic alloys will be required for sour conditions beyond the safe limits for 25% Cr superduplex.

Flow spools will incorporate butt welds, possibly with buttered joint faces, and hub or flange connectors: the fabrication guidance in Section 6.6 is applicable.

External painting of the completed spools is recommended in all cases; refer to Chapter 14.

5.6 External Corrosion Protection

Protective coatings and/or insulation in conjunction with CP, as discussed in Chapters 13 and 14, provide external corrosion protection.

6. Manifold Piping and Equipment

6.1 Introduction

Subsea manifolds transport, control and sometimes pump the co-mingled production fluids from the wellheads to the processing facilities, and/or the injection water or gas into wellheads. Manifolds typically comprise an assembly of piping, valves, control modules, instrumentation and associated fittings supported within a framework of structural steel. More recent designs may incorporate additional equipment items such as multiphase pumps and associated suction and discharge vessels. Some manifolds also serve as drilling templates, though recent trends have been to use 'cluster' manifolds for tying-in individual satellite wells to flowlines back to a processing facility. Towhead manifolds are used for bundled pipelines installed by towing. Typical manifold types are shown schematically in Figure 7.

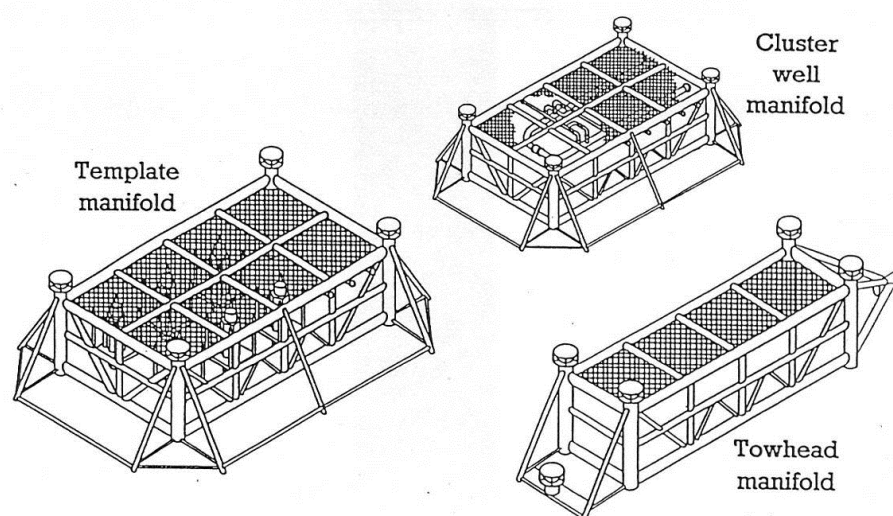


Figure 7 Some typical subsea manifolds

The requirements for materials and fabrication of manifold piping and fittings are extensively described in ISO 13628-15 and the recommendations made in this section are additional to these. The relevant sections of ISO 13628-15 are:

7	Materials and fabrication requirements to piping systems...
7.1	General.....
7.2	Pipe and pipe fittings
7.3	Forged components
7.4	Chemical composition and weldability
7.5	Test sampling of base materials
7.6	Mechanical and corrosion testing of base materials
7.7	Non-destructive inspection of components
7.8	Fastener materials
7.9	Bending and forming operations
7.10	Overlay welding and buttering of components
7.11	Welding and non-destructive testing of piping systems.....

Many different materials may be used for subsea manifold piping and equipment, based on a number of different manufacturing and construction techniques. Acceptable sources of materials include forgings, castings and hot isostatic

pressings (HIP) from powder. Each product has benefits, but forgings and HIPped products are usually considered to have the highest integrity and should be the first choice material. Seamless or longitudinally arc welded pipe may also be used, with branch connections extruded from the main pipe-run by either hot or cold working. Where sour service is applicable to carbon and low alloy steel, a low sulphur, calcium treated and vacuum degassed grade should be used (see Section 3.6), especially for seam welded piping components.

ERW / HFI piping is not generally recommended for use in manifolds and the available thicknesses for the typical diameters of interest make it unlikely to meet design requirements. It is not permitted in ISO 13628-15.

Connections to the manifold from the wellheads, and from the flowlines to the processing facilities may be either flexible jumpers or rigid pipeline spools, made up by suitable flanged joints or proprietary connectors.

Figure 8 illustrates a cluster manifold connected to eight satellite wells, with flowlines to the processing facility.

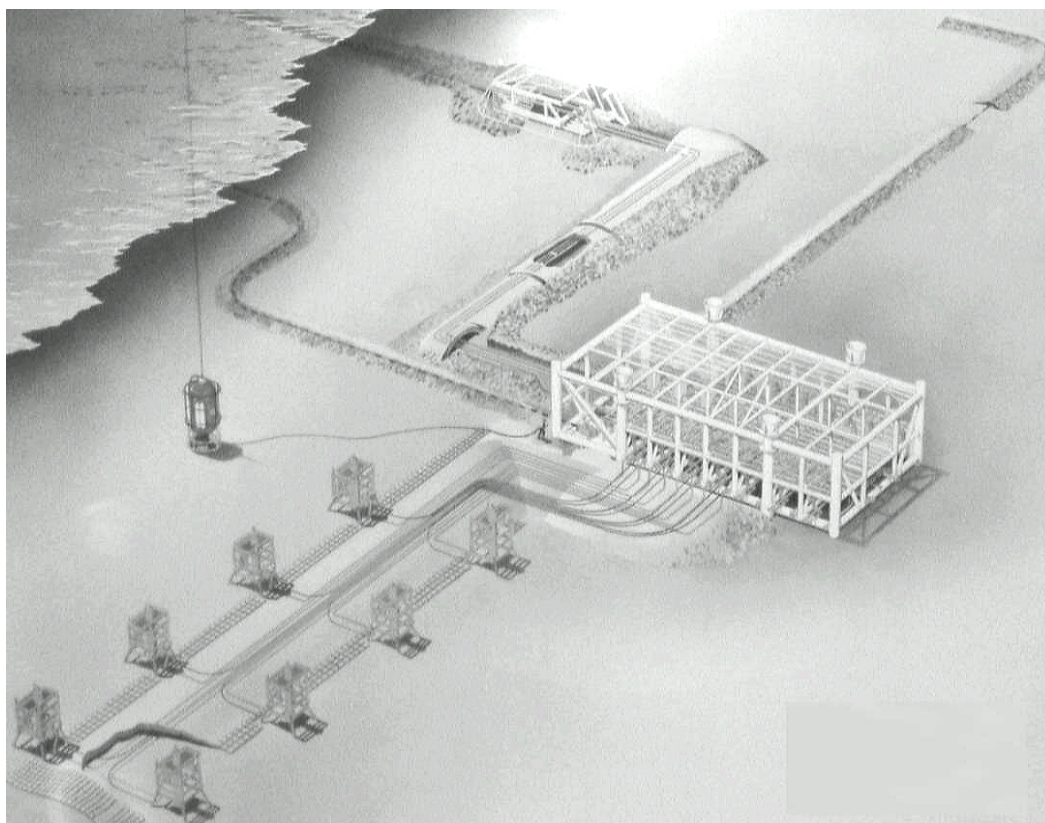


Figure 8 Cluster manifold connected to eight satellite wells

Auxiliary connections to the manifold may be made to facilitate injection of scale and/or corrosion inhibitor and sometimes H_2S scavengers, often via umbilicals, as described in Chapters 11 and 12.

6.2 Design Codes

The design and construction codes used for manifold piping include ASME B31.3,

ASME B31.4, ASME B31.8, API RP 1111 and the DNV Rules. These codes specify allowable stresses for piping components manufactured from seamless pipe, plate, castings, forgings, and by HIP.

For high-pressure manifolds, Chapter IX of B31.3 allows the use of a yield stress based criterion for determining the allowable stress, and this should allow reduced metal thickness compared with standard allowable stresses. However, more severe fracture toughness property requirements are stipulated that may be difficult to achieve with some materials.

For duplex stainless steel manifold piping, the recommendations of DNV-RP-F112 should be observed. This RP was produced following several failures of duplex stainless steel subsea components due to external hydrogen charging and hydrogen induced stress cracking at high stress locations. The RP gives guidance on design stress / strain criteria to avoid this problem, but does need to be applied at the commencement of detailed design to minimise the extent of complex or finite element analysis.

Pressure vessels are typically designed and constructed to either ASME VIII or to BS PD 5500. BS EN 13445 is also likely to be used with increasing frequency in the future. That standard has the advantage of giving presumption of conformity to the European Pressure Equipment Directive.

6.3 Typical Fabrication

Manifold piping is commonly sized in the 50–400 mm diameter range, with wall thicknesses up to around 80 mm. Fabrication may be by welded tees, extrusions, HIP tees in sections containing several outlets, or from pipe with 'sweeplet' or 'weldolet' (or similar proprietary) branch connections. For subsea design, a minimum of welding is advantageous, and weld profiles should be of reasonably smooth finish to avoid crevices—potential sites of corrosion and stress concentrations—and to facilitate coating.

The external surfaces of manifold piping and vessels, whether carbon steel or CRA, should always be coated for corrosion protection and to reduce anode drain on the CP system. However, if the items are to be coated with thermal insulation, then consideration should be given to applying an anti-corrosion coating (see Chapter 14). Typical deep water subsea production manifolds are shown in Figure 9 overleaf.

6.4 Duties

Subsea manifold duties include:

- producing reservoir fluids—oil, gas and produced water;
- injection water which could be raw or treated sea water, wash water or produced water; and
- injection gas for storage or productivity enhancement.

The material requirements for each of these duties are dependent on the corrosivity of the fluids and the life span of the field development.



Figure 9 Typical deep water production manifolds during fabrication

6.5 Materials Options for Piping and Vessels

Subsea manifolds are usually highly critical assemblies, the functional loss of which would have severe consequences for production. Hence materials selection for manifold piping and vessels should reflect the consequential requirement for high reliability and controlled resistance to corrosion that would avoid fluid leakage in service. Manifold piping is often of complex and compact design, and selected materials need to be commercially available in all the required product forms, and capable of being fabricated by conventional processes.

The first choice material for all hydrocarbon duties is usually a CRA of appropriate strength and fracture toughness to give a reliable, minimum weight facility. Due to the complexity of manifold piping design, which will include branched fittings, valves, dead legs and instrumentation, effective corrosion inhibition of carbon steel would be difficult to achieve and it would be difficult or impossible to execute adequate in-service corrosion monitoring and inspection. However if the field life is short, typically less than 10 years, and the hydrocarbon fluids are benign, then carbon steel with a suitable corrosion allowance may be appropriate, especially for shallow water installations.

For CRAs the primary options include:

- duplex and superduplex stainless steel;
- internally clad carbon steel, typically using Alloy 625.

However, under certain specific conditions the following may be considered suitable:

- super-austenitic stainless steel;
- Alloy 625, Alloy 825, Alloy 24 (UNS S34565).

Water injection and gas lift manifold piping will usually be constructed of carbon steel with corrosion allowance, as the water is de-aerated and the gas for injection is dehydrated. Where the quality of the injection water cannot be guaranteed to meet the usual criteria, and where the flowlines to the manifold are plastic-lined, consumption of residual oxygen by corrosion will not occur upstream of the manifold, hence the use of a CRA for the manifold piping may need to be considered, e.g. 22%Cr duplex stainless steel. Where injection water is not treated, then superduplex stainless steel and titanium are the optimum selections

for high pressure, ambient temperature, raw seawater. For non-treated injection gas, carbon steel or CRA may be selected according to the corrosivity of the gas.

Whenever H₂S is present in the hydrocarbon fluids, ISO 15156/NACE MR0175 should be applied. The further level of testing to NACE TM0177 and TM0284 to assess resistance of the materials to SSC and HIC respectively should also be considered.

For manifold piping fasteners see Chapter 9.

6.6 Hub and Flange Connectors

The preferred materials for hub connectors are forged CRA and weld-clad carbon manganese or low alloy steels of the F22 type.

Under most process conditions, duplex or superduplex stainless steels will be the CRA material of choice. Good manufacturing controls are required to ensure homogeneous, fine-grained microstructures, free from detrimental tertiary phases.

External surfaces of CRA pipework and hubs should be protected with a high integrity coating in order to prevent hydrogen charging and embrittlement (see Appendix III). This is particularly important for weld zones, external changes in section, and locations of potentially high stress.

In-service stresses should be fully analysed and catered for in design, including application of DNV-RP-F112 for duplex stainless steels. Additional fabrication-induced stresses should be minimised by application of planned and controlled assembly procedures and fit-up.

It is also common practice to select CRA weld overlaid carbon manganese or low alloy steel for hub/ROV connectors. In the case of low alloy steels, great care needs to be exercised in the selection of the CRA-substrate combinations as a brittle fusion line can develop, e.g. Alloy 625 and/or 725 weld overlays on AISI 4130 and 8630. Post weld heat treatment (PWHT) has been found to exacerbate this problem. It is therefore recommended that high strength low alloy steels of this type be avoided, in favour of carbon manganese steels. Where low alloy steels are required to achieve the through thickness hardenability requirements for high pressure designs, then the F22 grade is recommended on account of its lower carbon content. As highlighted in ISO 13628-15, some failures have occurred in the brittle fusion line between low alloy steels of the AISI 4130 / 8630 type and nickel alloys 625 or 725 due to a combination of:

- high tensile residual stress acting normal to the fusion line,
- high localized concentration of hydrogen, and
- the presence of a sensitive microstructure.

Figure 10 shows an undesirable joint design that has led to failure by a hydrogen embrittlement mechanism. In this example, a very narrow band of complex microstructure containing brittle precipitates forms adjacent to the fusion line between the low alloy steel component and the Alloy 625 buttering, largely due to carbon migration from the low alloy steel into the CRA weld metal. Most of this precipitation is believed to form during the PWHT which is required to temper the HAZ of the low alloy steel. Carbon diffusion and carbide precipitation are

generally acknowledged as being more severe in medium carbon low alloy steels of the 4130 / 8630 type. Buttering and PWHT is a frequently used method of manufacture of manifold components because site assembly can then be made by Alloy 625 closing welds without any requirement for further PWHT. Sources of hydrogen to promote brittle fracture along the fusion line include the welding process and external cathodic protection at locations of coating breakdown.

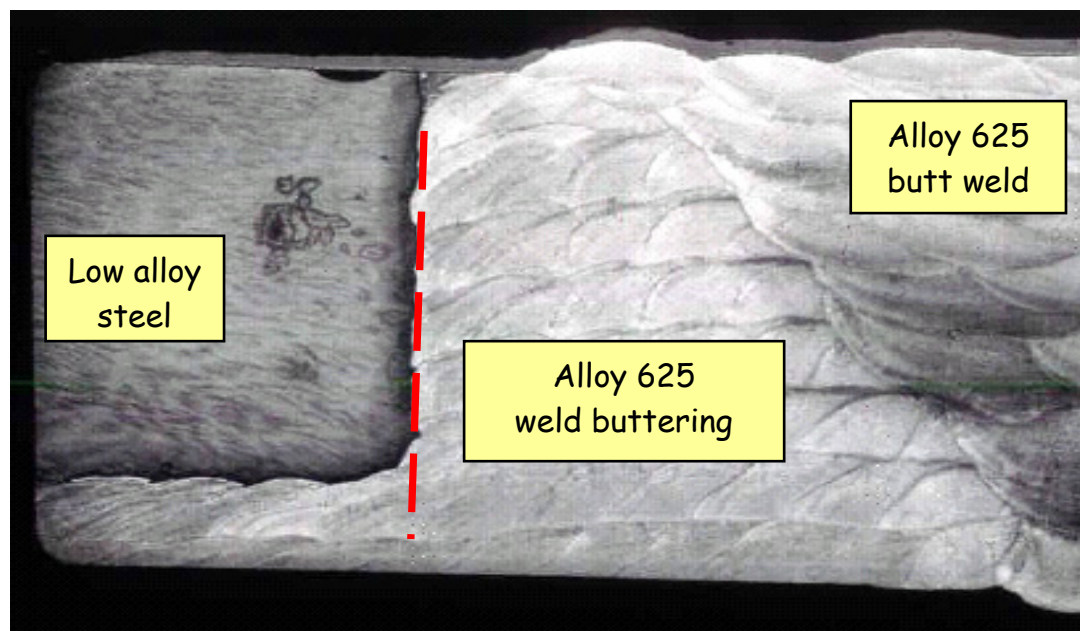


Figure 10 Non-recommended design of welded joint for low alloy steel manifold components

The dashed red line indicates the plane of potential weakness due to formation of brittle phases during the butter welding and PWHT processes.

Ideally, manifold components should be specified in internally clad carbon steels such that PWHT is not required, thereby avoiding the embrittlement problem. For high pressure designs however, low alloy steels of greater hardenability may be required, in which case the recommended alternative fabrication methods shown in Figures 11 and 12 should be considered.

Where carbon steel hubs or flanges are mated to CRA hubs or flanges, it is recommended that the mating face of the carbon steel material is fully weld overlaid with Alloy 625.

6.7 Multiphase Pumps

Multiphase pumps are becoming an increasingly attractive method to increase well productivity, and may be incorporated into tree flowbases, into production manifolds or may be stand-alone assemblies. The designs are proprietary and are individually customized for each specific application. Due to the relatively high velocities and turbulence in the pumps, CRAs are considered essential in every case, typically either duplex or superduplex stainless steel for the casings and internals wetted by the production fluids.

Pumps are usually of the multi-stage cartridge type such that the cylindrical casing is designed and constructed to pressure vessel codes.

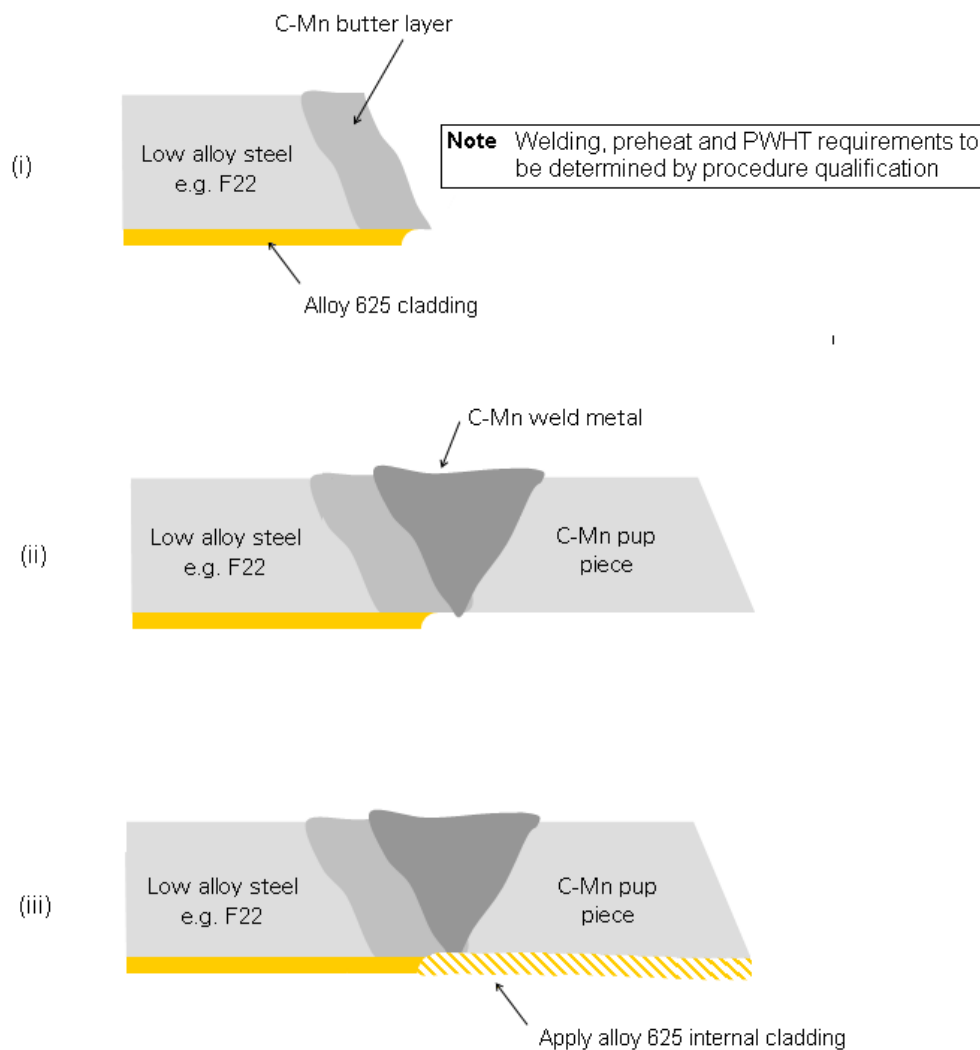


Figure 11 Option 1 for fabrication of low alloy steel components and valve bodies with C-Mn buttering layer, welded to C-Mn steel pup piece with C-Mn butt weld

Internals may require the application erosion resistant materials when sand production is expected, though some designs aim to maintain relatively low velocities within the pump, thereby avoiding excessive rates of erosion.

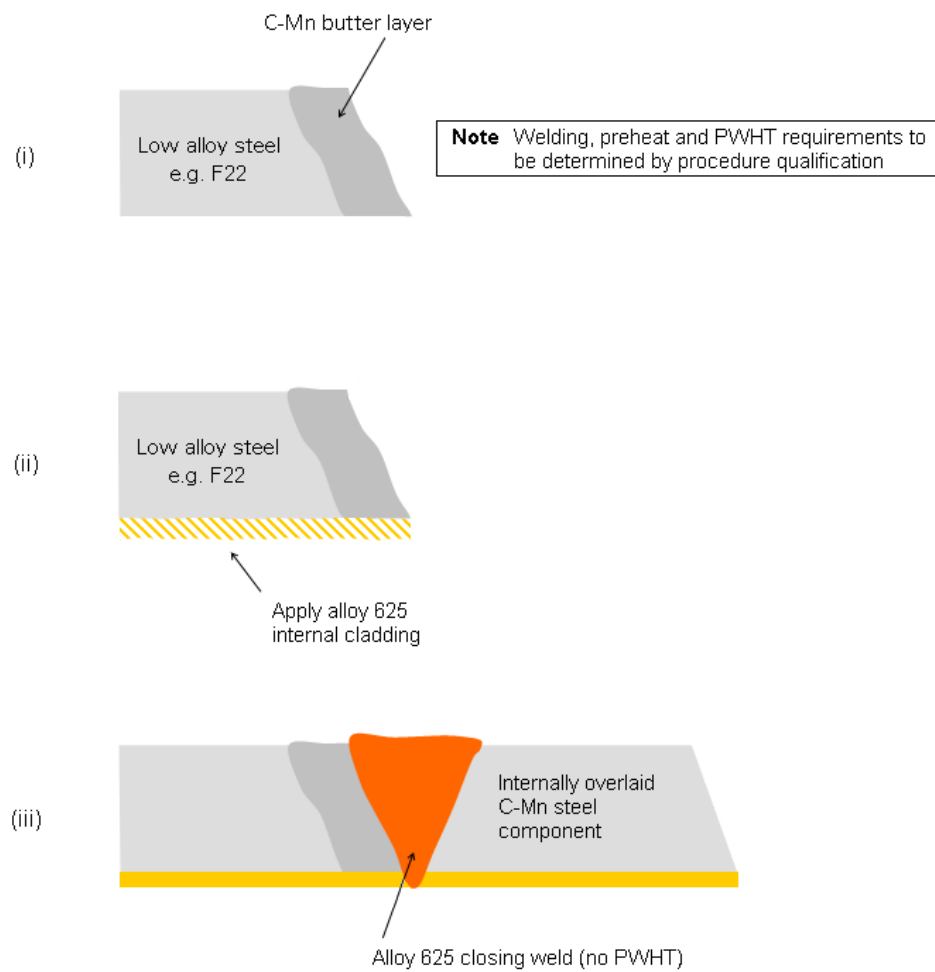


Figure 12 Option 2 for fabrication of low alloy steel components and valve bodies with C-Mn buttering layer, welded to C-Mn steel pup piece with Alloy 625 butt weld

7. Flowlines and Risers

7.1 Introduction

This Chapter describes the function and service conditions of subsea flowlines and risers, discusses the operational and economic parameters of their design, and indicates current recommended practice on materials selection and fabrication. Areas of application include:

- flowlines from subsea trees to production manifolds (and between cluster trees);
- flowlines from production manifolds to seabed terminations such as PLEMs (pipeline end manifolds);
- vertical riser assemblies from the seabed to the processing unit (platform or floating production unit); and
- flowlines from production manifolds to processing units via catenary risers.

7.2 Service

Subsea flowlines and risers may be used to carry the following fluids:

- production fluids,
- injection/wash water,
- injection gas,
- chemicals, and
- heating medium.

Production fluids will be untreated, will probably contain water and CO₂, and are therefore likely to be corrosive. H₂S may also be present.

Injection and wash water are normally de-oxygenated seawater and/or reinjected formation water, although increasing use is being made of untreated seawater. Injection gas is usually processed, dry, and non-corrosive; but wet gas, sometimes with increased levels of CO₂ and H₂S from fluid processing, and highly corrosive, is also injected.

7.3 Subsea Flowline Design

7.3.1 Flowlines from Trees to Manifolds (and between Cluster Trees)

Flowlines from subsea trees to the manifolds (sometimes called jumpers) may be flexible piping (See Chapter 10) or rigid pipework. In the latter case the pipework may be designed to either a process pipework code (e.g. ASME B31.3) or a pipeline code (BSI PD 8010 Pt 2, ASME B31.4 or B31.8, or DNV OS-F101). These lines are normally short and, if in rigid pipe, usually installed as prefabricated spool pieces. As with manifold piping, duplex stainless steel flowlines should be designed in accordance with DNV RP-F112.

7.3.2 Flowlines from Manifold to Processing Unit

The processing unit may be a production platform, floating production unit or onshore facility. Flowlines between the manifold and the processing unit (also called inter-field or infield lines) may vary in length from, typically, 1 km to over 60 km. Short lines may be in flexible pipe but most are rigid, metallic pipelines

installed in relatively shallow water by conventional S-lay barge, by reeling, or as a towed bundle. Such lines are almost invariably designed to a pipeline code (BSI PD 8010 Pt 2, ASME B31.4 or B31.8). For deep water, installation by the J-lay method may be required.

7.4 Materials Options

7.4.1 Introduction

Materials selection for flowlines and risers is dependent upon the corrosivity of the fluid carried, which, in turn, is dependent upon:

- chemical content of the fluid; and
- operating conditions, i.e. temperature, pressure, flow rate.

Other factors affecting materials selection include:

- Required service life.
- Risk (probability and consequence of failure).
- Economic considerations, such as:
 - capital cost (material and installation);
 - operational cost (corrosion inhibition, monitoring and inspection); and
 - strength-to-weight ratio (for risers).

Material options are discussed below in relation to the fluid carried.

7.4.2 Flowlines Carrying Production Fluids

7.4.2.1 General

Production fluids in flowlines may be gas, oil or multiphase and, as stated above, these fluids are untreated and contain condensed or formation water. As they will probably also contain CO₂, they are likely to be corrosive to carbon steel. H₂S may also be present, in which case precautions need to be taken against SSC and HIC in carbon and low alloy steels. There is also a risk of H₂S-induced SCC in CRA materials, which may limit the use of some of these alloys (selection of materials is discussed in Section 3.6.2). Temperatures and pressures may also be higher than those encountered in surface process equipment.

Risk and economic factors will favour the use of CRAs for tree-to-manifold product flowlines, unless they are unusually long, or conditions are particularly benign, or the required service life is short. For flexible flowlines, the internal supporting carcass is normally austenitic (316L) or duplex stainless steel, which is adequate for most conditions (see Appendix II). Rigid tree-to-manifold flowlines are normally fabricated from duplex stainless steel or from carbon steel internally clad with CRA (carbon steel may be considered for short service lives or particularly benign conditions).

Materials selection for product flowlines from manifold to processing unit is more dependent on economic considerations. Although flowlines in CRA or CRA-clad or -lined pipe will give the lowest operational cost and risk, the high capital cost may, for a longer flowline, be prohibitive. It is therefore normal practice to assess the feasibility and cost of flowlines in carbon steel where internal corrosion can be reliably controlled, usually by inhibitor injection at the manifold. CRAs are

then only considered where the corrosion rates are too high or where the operational cost of corrosion control and monitoring exceeds the higher capital costs involved.

7.4.2.2 Carbon Steel Flowlines for Production Fluids

Carbon steel line pipe for subsea applications is normally procured to one of the following standards:

- API Spec 5L
- ISO 3183
- DNV OS-F101.

While DNV OS-F101 is specifically directed to submarine pipeline systems the ISO and API standards deal with line pipe in general. Consequently, the additional requirements in Annex J of API Spec 5L/ISO 3183 will need to be specified when using the ISO/API standards for offshore applications and further additional testing may be necessary for pipe subject to high strain (>0.5%) during installation, for example, installation by reeling. DNV OS-F101 provides guidance on the appropriate testing for high strain installation techniques.

In order for internal corrosion to occur in carbon steel systems carrying hydrocarbons, it is necessary for both water (in liquid form) and carbon dioxide to be present. (Where water exists only in the vapour phase, i.e. the temperature is above the dew point, corrosion will not take place). H₂S can cause corrosion-related cracking, as described above, but at low concentrations (partial pressures less than 0.1 bar) will not appreciably affect the corrosion rate. See Section 3.6.3 for estimation of corrosion rates due to carbon dioxide. Such corrosion is normally mitigated by the use of chemicals (corrosion inhibitors, pH modifiers) injected into the product stream. The effectiveness of the chemical treatment in a particular system is dependent on such factors as fluid velocity, flow regime and the presence of other chemicals (e.g. methanol or glycol injected to control the formation of hydrate can increase the effectiveness of corrosion inhibition by combining with the available water).

The effectiveness of chemical treatment in operation will be a combination of the efficiency of the chemicals themselves (as determined by laboratory tests, and which may be very high) and the fraction of time during which they are correctly applied. In practice, their injection may be interrupted by equipment malfunction or human error, and the dose may not be correctly adjusted to take account of changing conditions. One alternative approach is to use an inhibited corrosion rate, usually 0.1 mm/year (as verified by laboratory tests but independent of the uninhibited corrosion rate), but assume that this is only effective for a certain percentage of the time, and for the rest of the time corrosion proceeds at the full, uninhibited rate. The percentage of time the corrosion treatment is considered to be effective will depend on operational experience of the location and pipeline conditions, but is unlikely to be more than 95% unless a high reliability system design has been adopted. The selection of high persistency filming corrosion inhibitors will help achieve optimum protection, since these will reduce corrosion during periods of non-injection.

The performance of the corrosion treatments will also be determined by the flow regime. In particular, caution needs to be exercised at velocities greater than 15 m/sec and under slug flow conditions.

The required corrosion allowance for a pipeline is the sum of the inhibited and uninhibited time-fraction corrosion losses over the operational design life. Required corrosion allowances of more than about 10 mm would indicate that carbon steel is unsuitable. Even at lower corrosion rates the costs of inhibition and monitoring may be excessive, particularly at high rates of water production. In these situations the use of CRAs should be considered.

The monitoring of the effectiveness of corrosion treatment is of critical importance in the safe and economic operation of wet hydrocarbon lines. Corrosion rates may be monitored at the following three locations:

- **At the manifold.** The corrosivity of pipeline fluids may be measured at the entry to the flowline by means of corrosion probes mounted within the manifold pipework. Probes need to be capable of being remotely interrogated, and metal-loss types such as electrical resistance may be used for this purpose. Duplication of probes with possibly different designs should be considered for maximum reliability. Erosion probes may be similarly installed.
- **Within the pipeline.** Corrosion within the pipeline itself may be directly measured by means of instrumented spools installed in the line. The main advantage of such systems is that corrosion within the pipeline can be measured directly at locations around the full circumference of the pipe. The main disadvantages are the high cost and the fact that corrosion is only measured at one point in the line; this point needs to be selected at a location representative of the highest corrosion rate occurring in the line. The long-term performance of such equipment and the reliability of the data obtained should be established.
- **At pipeline outlet.** The corrosivity of the water phase in wet hydrocarbon flowlines may be measured most conveniently in the water stream from the separator or slug catcher at the flowline outlet. This may be done by sampling, or with electrical resistance probes and/or weight loss coupons. As the corrosion inhibitor will still be present in the water stream, the inhibited rate will be measured. The main disadvantage is that the corrosion rate is measured for the pipeline outlet conditions, and adjustment needs to be made for conditions further upstream, particularly with regard to temperature. An assessment of the effectiveness of inhibition may also be made from analysing the quantity of iron in this water ('iron count').

In addition to these methods, flowline corrosion may be directly measured on larger lines by intelligent pigging, but this is an expensive method that cannot be deployed regularly, and is used to verify the condition of the line rather than to monitor the ongoing effectiveness of the corrosion inhibition. Temporary subsea pig launchers can be used for shallow waters whereas round trip pigging designs are normally required for deep water.

Further guidance on corrosion monitoring is available in NACE Report 1D199 and in ISO 21457.

Guidance on the precautions to be taken and the safe operating limits for carbon and low alloy steels in sour service are given in Section 3.6.2 and the various standards referenced herein. Careful consideration should be given to the specification and qualification of line pipe of API 5L grade X70 and above for sour service, manufactured by any route.

7.4.2.3 Corrosion Resistant Flowlines for Production Fluids

Suitable corrosion resistant materials include:

- Duplex stainless steel (both the 22%Cr, UNS S31803 type and the 25% Cr grades such as S32550, S32750, S32760).
- Low carbon weldable grades of martensitic 13% Cr stainless steels specifically developed for pipelines.
- Carbon steel internally clad with CRA, typically Type 316 stainless steel or Alloys 825 or 625 ('clad' signifies that the alloy layer is metallurgically bonded to the carbon steel substrate).
- Carbon steels lined with CRA. In this case the alloy liner (usually Types 316L or 904L stainless steel or Alloy 825) is mechanically expanded onto the internal surface of the carbon steel, without a metallurgical bond.

Other CRAs would exhibit sufficient corrosion resistance, but are not commonly used for flowlines due to low yield strength (e.g. Type 316L) or high cost (e.g. Alloy 625).

Plastic-lined pipe (see Section 7.5.3) has been employed for hydrocarbon service onshore, using both polyethylene (high and medium density) and polyamide (nylon), the latter coating being used at temperatures up to 65°C with high H₂S contents. At present, its use for offshore hydrocarbon flowlines has not been reported.

Duplex stainless steels. Despite their relatively high cost, duplex stainless steels have been widely used for production flowlines. Pipe is available in both seamless and longitudinally welded forms. The advantages of these steels include:

- high yield strength (typically 450 MPa for S31803, 550 MPa for 25% Cr steels),
- good toughness,
- good weldability,
- sufficient corrosion resistance for most production fluids up to 150°C, and
- high resistance to SCC in oxygen/chloride environments.

Limitations include:

- reduction in yield strength with increasing temperature,
- SCC in hydrogen sulphide/chloride environments, and
- hydrogen embrittlement due to CP in combination with high local stresses.

Appendix III contains further information on these materials for flowline applications.

Martensitic stainless steels. Weldable low carbon grade 13% Cr steels have been developed specifically as pipeline materials, and several flowlines have been laid in these materials. The advantages of these materials include:

- lower cost than duplex stainless steel,
- high allowable design stresses, and
- less reduction in strength with temperature than duplex stainless steel.

Limitations include:

- likely requirement for PWHT,
- lower resistance than duplex stainless steel to sour service conditions,
- hydrogen embrittlement due to CP, and
- poor availability of fittings in matching materials.

For further details on the properties and application of these materials refer to Appendix IV.

Carbon steel internally clad/lined with CRA. These materials consist of carbon steel line pipe (normally conforming to API 5L grades, e.g. X60 or X65) with an internal layer of CRA, usually 2–3 mm thick. The main advantages of clad/lined line pipe are:

- lower cost than solid CRA in some cases,
- ability to use lower strength corrosion resistant layer with high strength substrate, and
- avoidance of hydrogen embrittlement from CP.

The main disadvantage of clad/lined pipe is its limited availability.

The cost savings of clad pipe over solid CRA are more apparent at larger diameters and wall thicknesses, particularly where longitudinally welded clad pipe may be used. Lined pipe allows cost savings at smaller diameters. The ability to use lower strength alloys for the internal layer is of particular advantage under severe process conditions (e.g. high H₂S contents) where duplex stainless steel would be unsuitable, and a corrosion resistant but low strength nickel based alloy (e.g. Alloy 825) could be used with a high strength carbon steel substrate (e.g. X65).

Plate for longitudinally welded line pipe is usually clad by roll bonding, or less often by explosive cladding and rolling, prior to pipe forming. This necessitates solution annealing the plate after bonding to restore the properties of the CRA layer, which can reduce the properties of the substrate. For this reason, alloys with lower annealing temperatures (316L or Alloy 825) are favoured over those with high annealing temperatures (duplex stainless steel, Alloy 28). Seamless clad pipe is generally produced by internal weld overlay.

For lined pipe, the CRA liner is inserted and hydraulically or thermo-hydraulically expanded into the substrate pipe, producing a mechanical grip (but not a metallurgical bond) between the two pipes. The CRAs most commonly used for mechanically expanded liners are low yield strength austenitic alloys, usually 316L and 904L stainless steel, or Alloy 825. Higher yield strength duplex or martensitic stainless steel have not been used, the main concern being reduced gripping strength of the liner to the outer pipe. The liner–substrate interface at the pipe ends is then seal welded.

Clad pipe has been successfully installed by most pipelay methods including reeling, and is also suitable for induction bending. Lined pipe has not to date been considered suitable for installation by reel barge though this view may change on the basis of on-going development work.

Further details on clad and lined pipe are given in Appendix V.

7.4.3 Flowlines Carrying Other Products

7.4.3.1 Injection/Wash Water

Although injection/wash water is normally de-aerated to a design limit of 10 ppb oxygen or less, excursions to higher oxygen contents can occur, causing considerable corrosion in carbon steel lines. Localised corrosion at the bottom-of-line and at girth welds can develop, and evidence of accelerated corrosion due to microbial activity and deposited debris has been reported. Similar observations are made in ISO 21457.

Provision of a corrosion allowance of at least 3 mm for unlined water injection flowlines is advised. Where consistent achievement of the 10 ppb dissolved oxygen limit cannot be guaranteed, a higher corrosion allowance or alternative material should be considered. Removal of mill scale from the internal surface by grit blasting is also recommended (mill scale is cathodic to bare steel in these conditions and can plug the formation into which the water is being injected) and welding consumables containing about 1% nickel or nickel and copper are usually specified to minimise preferential weld corrosion. The use of unlined, carbon steel flowlines involves a risk of failure, and successful operation of such lines is dependent upon rigid adherence to operational procedures designed to minimise internal corrosion, including the removal of debris.

Over recent years, carbon steel with a plastic (polyethylene) liner has become commonly used for offshore water injection flowlines. Although of higher capital cost, such lines are immune to corrosion arising from excursions in oxygen content, and may be used to carry raw seawater.

22% Cr duplex stainless steel is suitable for treated injection water at temperatures up to 30°C and within qualified limits of oxygen and residual chlorine levels. NORSOK M-001 recommends qualification is based on 'oxygen equivalents' of 50 ppb for 90% of operational time and 200 ppb for 10% of operational time. Oxygen equivalent is defined in NORSOK as ppb oxygen + 0.3 x ppb free chlorine.

Marginal reservoir injectivity may dictate a CRA or plastic lined carbon steel flowline in order to prevent the inevitable corrosion products from plugging the formation.

Carbon steel is not suitable for raw seawater injection lines unless polyethylene lined. Non-plastic lined pipe should be specified in stainless steel or nickel based alloy with a PREN > 40, or carbon steel pipe clad/lined with such materials, or in titanium.

Spoolable fibre reinforced plastic composite flowlines are available and have been used onshore in a range of production and injection applications. Offshore experience is strictly limited at this time, but one subsea application involves the use of spoolable composites for rehabilitation as slip liners within corroded flowlines. This technology has found its first applications in shallow water Gulf of Mexico fields. API RP 15S provides guidelines for the design, manufacture, qualification and application of spoolable reinforced plastic pipe for transport of multiphase fluids, hydrocarbons and water.

7.4.3.2 Gas Injection

Where the gas for injection is dry, flowlines may be in carbon steel with a small corrosion allowance (e.g. 1 mm) to allow for installation and upset conditions. Where wet gas is to be injected, materials selection should be made on the same basis as that for production fluids.

7.4.3.3 Chemicals (Service Lines)

Bulk chemicals, such as glycol or methanol used for hydrate suppression, may be transported to the wellhead or manifold in small diameter pipelines, possibly using coiled tubing. Where these chemicals are non-corrosive (which is usually the case) such pipelines are normally fabricated in carbon steel with a nominal corrosion allowance. Injection chemicals required in smaller quantities, e.g. corrosion or scale inhibitors, are usually transported in small diameter tubing within umbilicals (see Chapter 12). Such tubing is normally in austenitic (316L) or duplex stainless steel.

7.4.3.4 Heating Medium

A heating medium (usually potable water or water-glycol mixtures) is occasionally supplied to the manifold by small diameter pipeline. Such lines are normally constructed of carbon steel with a small corrosion allowance (see Section 7.5.2.3).

7.5 Installation of Subsea Flowlines

7.5.1 Installation Methods

7.5.1.1 General

As stated above, short flowlines (up to approx. 200 metres) may be installed as spool pieces fabricated to the exact, surveyed length. Longer subsea flowlines may be installed by one of the following methods:

- conventional lay vessel (S-lay),
- J-lay vessel,
- reel barge,
- towed bundle, and
- coiled tubing (outside diameters < approx. 150 mm).

7.5.1.2 Conventional S-Lay

Conventional S-lay vessels install the vast majority of offshore pipelines greater than 16 inch (DN 400) and a reasonable proportion below that size. During installation, the pipe takes on the characteristic 'S' shape due to the overbend on the stinger and the sag bend at the seabed. The pipe strains encountered are usually around 0.2–0.4%. The pipeline is held in position by tensioners mounted on the vessel that grip the outer surface of the pipe.

Post-installation activities such as ploughing and trenching can induce further strains of similar magnitude, some of which may be plastic.

Most pipeline types have been installed by conventional S-lay vessels, including carbon steel, solid CRA, metallurgically bonded and lined pipe. An exception is internally plastic lined pipe where the cost of connectors at the end of each joint has inhibited the use of conventional vessels for economic reasons.

7.5.1.3 J-Lay

For deep water developments, J-lay has become the standard method for pipelay. Several vessels now have a J-lay capability, and even major trunk lines have been installed using this method.

The concept is similar to S-lay in that new pipe is welded to the line on the lay vessel, which moves forward by the length of the new pipe. The significant difference is that the pipe is introduced in the vertical or near vertical position. This eliminates the overbend, and allows deep water pipelay without requiring excessive tension. A drawback is the reduced number of available workstations: typically one or two compared with several stations on a conventional vessel. The larger J-lay vessels are modified semi-submersible crane vessels, and make use of their crane capacity to install 'quad' (48 m) or 'hex' (72 m) joints compared with the double or single joints seen on S-lay vessels. These greater joint lengths act to reduce the impact on productivity of the reduced station availability.

Whilst S-lay vessels invariably utilise tracked tensioners to control the pipeline installation, at least one J-lay vessel has replaced this method with integral pipeline collars that are held by a clamp.

One significant advantage of the J-lay method is that in-line termination units such as PLETs can be installed, as shown in Figure 13.

In contrast to the S-lay and J-lay methods, the techniques described in Section 7.5.1.4 through 7.5.1.6 use pipelines substantially welded onshore and then taken offshore for installation.

7.5.1.4 Reel Barge

In this method, lengths of pipeline ('stalks') of up to 1000 metres are welded, inspected and coated onshore. These lengths are, in turn, joined by welding as they are reeled onboard the lay vessel. Offshore pipe lay is then carried out in one continuous operation, see Figure 14. Pipelines of continuous lengths of many kilometres and up to 18 inch diameter (DN 450) and approximately 30 mm wall thickness can be laid by this method, the maximum length being dependent on the pipeline dimensions and reel barge capability. Longer pipelines may be installed by means of offshore tie-in welds.

The main advantages of the reeling method are:

- Nearly all welding, inspection and coating are carried out onshore, independently of the availability of the lay vessel, and offshore installation is relatively rapid thus minimising the cost of offshore operations. This is particularly important in the case of CRAs where the welding and inspection times are longer than for carbon steel.
- The method is suitable for the installation of plastic lined pipelines.

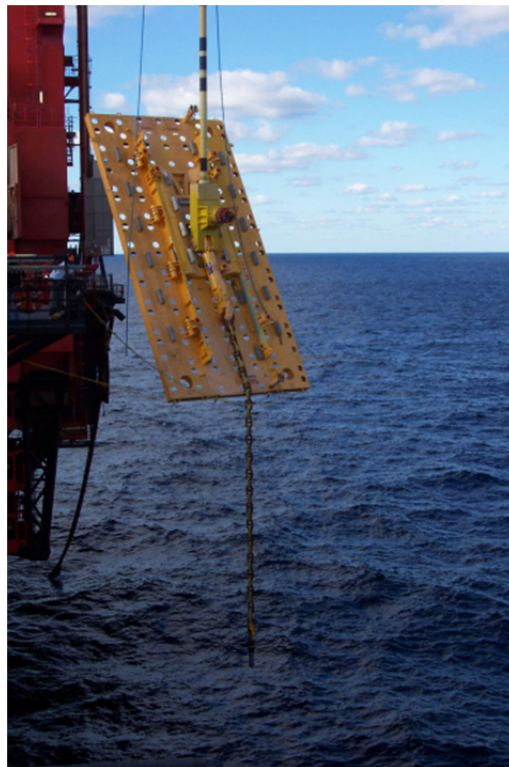


Figure 13 Installation of PLET from a J-lay vessel

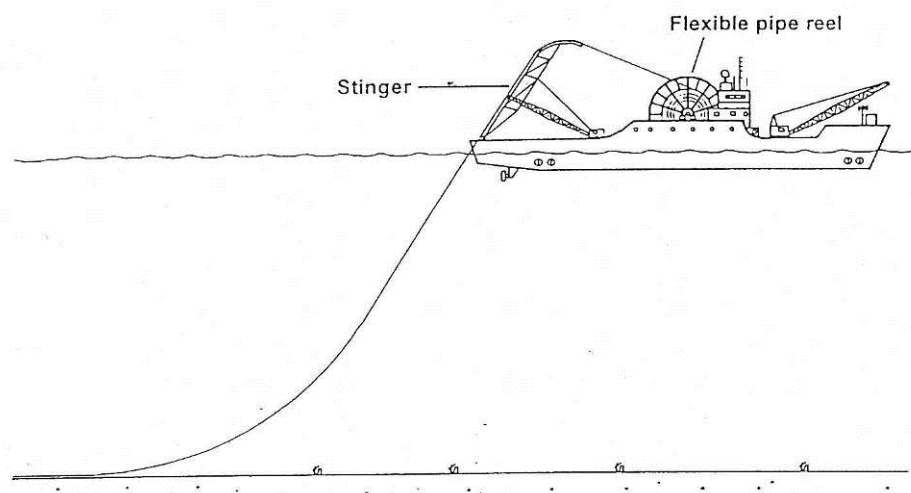


Figure 14 Installation of a subsea flowline by reeling

Disadvantages include:

- The limitations on diameter and wall thickness.
- Concrete weight coatings cannot be accommodated (material wall thickness needs to be selected to give stability without weight coating).
- The method would require qualification for CRA lined pipe (i.e. not metallurgically bonded) due to concerns over relative movement of the liner within the outer pipe and reduction in the gripping strength.

During reeling, the pipe material is taken past the yield point, experiencing plastic strains of up to 3%. On laying, the pipe is straightened, resulting in a reversal of plastic strain of the same magnitude. For small sections of pipe this cycle may be repeated up to three times during repositioning of the vessel. There is therefore a possibility of work hardening, strain ageing (particularly in the weld metal) or reduction in yield (due to the Bauschinger effect). For this reason, it has been the common practice to carry out tests simulating the strain cycle on sections of pipe (including welds) prior to production: areas of concern include an increase in yield strength due to strain hardening and a reduction in impact toughness at temperatures below about -20°C .

Particular caution is recommended where lean chemistry pipe is selected for reeling application. There is an increased risk of ductile failure at the girth butt weld toes due to HAZ softening caused by the weld heating cycle, overmatching weld metal strength, and the repeated strain cycles associated with reeling.

A maximum yield stress limit of 120 MPa above SMYS is usually specified to reduce both the risk of buckling during reeling, caused by adjoining low and high strength pipe, and that of overstraining of weld metal due to undermatching. Defect acceptance criteria as specified by normal pipeline welding codes (e.g. BS 4515) appear to be suitable for this application, at least for carbon steels. Consideration should be given to the possibility of delayed hydrogen cracking, especially for martensitic stainless steels (see Appendix IV). Low hydrogen welding practices are recommended in all cases.

7.5.1.5 Towed Bundle

In this method, several pipelines are installed as a bundle within a larger carrier pipe. Fabrication is carried out onshore, and the whole assembly is launched and towed to location at a controlled depth, the pipelines and carrier pipe being nitrogen filled during tow to provide buoyancy. Figure 15 illustrates the controlled depth tow method for bundle installation.

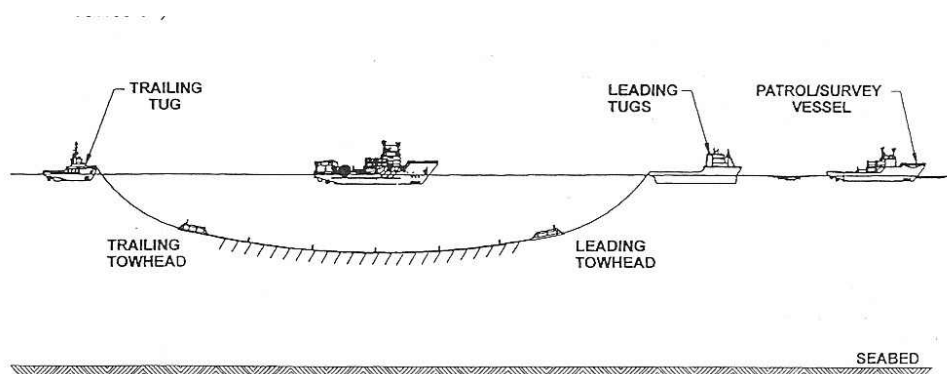


Figure 15 Bundle installation by the controlled depth tow method

After arrival at location the bundle is flooded to provide stability (the water being treated with corrosion inhibitor and biocide, and the carrier pipe, usually, sealed to prevent further corrosion).

Four or more pipes have been included in bundles, and carrier pipes of up to 44 inch diameter with individual towed lengths of over 7 km have been installed.

The outer pipe material has most frequently been API 5L grade X52 carbon steel. Figure 16 below shows a cross-section of a typical bundle.

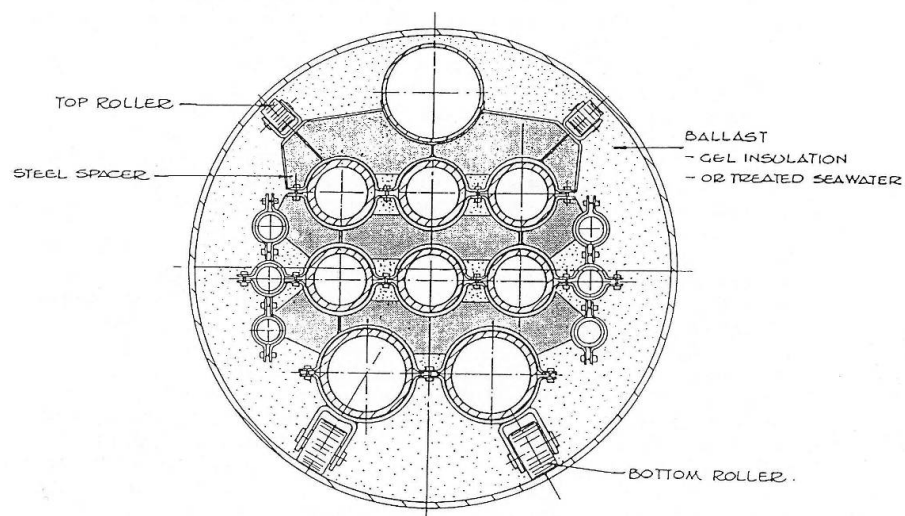


Figure 16 Cross-section through a typical pipeline bundle

The advantages of bundles include:

- All flowlines servicing one location (e.g. production flowline, water injection line, chemical injection line, and heating medium line) can be installed in one operation. Electro-hydraulic umbilicals can also be accommodated.
- Welding, inspection and coating operations are performed onshore, minimising offshore time. As with the reel barge method, this is of particular benefit for CRA pipelines (clad and unclad) where longer weld and inspection cycle times are involved compared with those for carbon steel.
- The method is suitable for the installation of CRA-lined carbon steel pipe.
- The method is suitable for the installation of plastic-lined pipe.
- The method offers scope for the incorporation of insulation materials that would be more difficult for a conventional lay barge.
- A heating medium may be circulated within the bundle.
- The wall thickness of the flowlines needs only to be calculated for hoop stress, not for installation stress or stability, and hence may be considerably reduced.
- CRA pipelines within the bundle are not affected by the external CP system, hence there is no risk of hydrogen embrittlement from this source.

Disadvantages of bundles include:

- The necessity of an onshore fabrication site of a length to accommodate that of the bundle, with suitable access to the sea for launching.
- Bundle dimensions are limited by the length and the outer diameter of the carrier pipe (although these limits are being extended and bundles can be joined during installation).
- The inherent engineering complexity and associated costs may not be economic for simple pipeline systems.

- If the carrier pipe is punctured allowing raw seawater entry, external corrosion of the flowlines or internal corrosion of the carrier pipe may occur. Design should cater for this risk.
- Potentially increased project risk, e.g. bundle failure during load-out.

Consideration needs to be given to the issues associated with bundle hydrotesting. If testing is done onshore, then the practicalities of water removal, and the associated corrosion risks of incomplete drying, need to be assessed. Pneumatic testing may be considered, but the safety risks will also need careful assessment. Ultimately it may be considered acceptable to postpone hydrotesting the carrier pipe until after installation on the seabed.

7.5.1.6 Coiled Line Pipe

In this method, the pipe is received as coiled rather than straight lengths. Circumferential welding is only required where necessary for joining these (longer) lengths. Pipe laying is carried out continuously, in a similar manner to that described above for the reel barge method. Very high lay rates, typically 600 metres/hour, have been reported.

Although coiled pipe is available in sizes up to 6 inches OD it is understood that only sizes up to 4.5 inches OD have been utilised to date. The smaller diameter lines have mostly been used for chemical injection while the larger diameters have been employed for gas lift, water injection and production service. Potential disadvantages associated with the use of coiled pipe include a lack of stability due to low wall thickness and the impossibility of weight coating.

Coiled line pipe may be manufactured in accordance with API 5LCP.

At present manufacturers specify steel strip for coiled pipe to ASTM A606 (with substantial modifications). Further development of material specifications is required, leading to incorporation in API 5L. It should be noted that, due to the necessity of heat-treating the electric resistance weld, the composition of the steel is critical, and tight limits should be set on chemical composition ranges. Variations outside these limits should require re-qualification of the manufacturing procedure.

The seam weld should be subjected to 100% volumetric NDT, using a qualified procedure which has been demonstrated to be capable of detecting significant defects through the full thickness of the weld, including those on the internal surface.

7.5.1.7 Other Techniques

Variations on the installation techniques for flowlines include:

- **Joining of flowline lengths using mechanical connections.** This is potentially a fast joining technique and would permit the use of cheaper, non-weldable 13% Cr steels as used for downhole tubulars. There is some resistance to the use of this method based on concern over the long-term integrity of the joint.
- **Piggyback pipelay.** A piggyback pipelay involves the simultaneous installation of a second pipeline with the main line. The piggyback line is typically fabricated on deck or alongside the main line, but only brought

close to the main line towards the rear of the vessel. At this point the piggyback line is attached to the main line by banding, usually with CRA straps and plastic spacing blocks. The main line then supports the piggyback as it passes to the seabed. It is normal practice to connect cables from the mainline anodes to the piggyback to provide CP. A typical piggyback application would be a 2–4 inch diameter glycol line attached to a larger hydrocarbon main line.

- **Dual lay.** In common with piggyback pipelay, dual lay is the simultaneous installation of two pipelines from one vessel. The difference is that the two pipelines remain isolated from one another. The second line is normally fabricated on deck, and departs the vessel by its own dedicated stinger. A disadvantage of dual lay is the extra cost of additional temporary equipment such as a stinger and tensioners. For longer lines this can be offset by increased productivity.
- **Pipe-in-pipe.** Pipe-in-pipe flowlines have become increasingly common with the increased desire to transport elevated temperature fluids without loss of heat. Flowlines of up to 70 km have been installed as pipe-in-pipe. Pipe-in-pipe tends to be selected where the thermal insulation requirements are too severe for coated pipe to be used. A typical system would comprise an inner pressure-retaining pipe carrying the hydrocarbon, a gap of 50–100 mm filled with insulation, and an outer pipe. The outer pipe is not usually designed to withstand the hydrocarbon pressure.

Variables include:

- Whether the insulation is used to transmit the shear forces from the outer pipe to the inner pipe during installation and operation.
- Whether expansion spools will be placed at intervals to absorb expansion strains or whether the pipeline will be free to move across the seabed. The latter method usually involves laying the pipeline with a series of gentle bends, sometimes known as snake lay.
- The spacing at which waterstops and bulkheads are installed.

Many techniques have been suggested and used for offshore pipe-in-pipe fabrication. The most commonly used method is known as the 'half shell', where the pipes are taken offshore as completed units for welding into the line. The outer pipe is shorter than the inner pipe to allow access for making the inner pipe weld. Upon completion of the inner pipe welding and NDT, a layer of insulation is placed on the weld, and the gap between the outer pipes is bridged with two half shells supported by pre-installed backing strips. Two full penetration longitudinal and two girth welds are then made to complete the joint. The advantages of this method include the robustness of the completed outer pipe, the relative ease of design, and that the loads can be transmitted through the insulation. The main disadvantages are the amount of welding required to complete the joints (five welds per joint) and the tight tolerances necessary to achieve adequate fit-up of the half shells.

Another technique that has been used offshore is to complete the inner pipe and then slide the outer pipe over it to close the gap. A single circumferential weld is then required to complete the joint.

Installation of pipe-in-pipe by reeling is also undertaken, and can eliminate the need for half shells.

7.5.2 Welding of Flowlines

7.5.2.1 General

The welding of flowlines is covered by established standards, notably ISO 13847, BS 4515, API 1104 and DNV OS-F101. Personnel responsible for the welding engineering need to be competent, and a qualified welding co-ordinator should be appointed for the work in accordance with ISO 14731.

The traditional method for the volumetric inspection of pipeline girth welds was radiography, usually with an internal X-ray source. Automatic ultrasonic testing (AUT) is now the pre-eminent NDT method for pipelines (see Appendix VII).

Internal visual inspection of solid CRA or internally clad/lined pipelines employing an internal video camera is recommended. The use of laser enhancement is also recommended to assist interpretation of the camera image.

7.5.2.2 Carbon Steel Flowlines—Offshore Welding

The principal method for the welding of flowlines offshore is mechanised GMAW, a proven process that continues to be developed and improved. The most common method of application is a 'bug and band' arrangement although fixed frames with the head traversing around the frame are used. The root bead is normally supported by copper backing shoes that are integral to the internal line-up clamp. It is the requirement for an internal line-up clamp that has led to a lower diameter limit of 6–8 inch for mechanised GMAW. Traversing a typical welding head around a small pipe is also difficult. Internal welding machines are rarely used for flowline welding due to the small diameters.

The dominance of mechanised GMAW is largely based on speed. One of the factors that assists good productivity is the ability to weld into narrow gaps thus reducing the amount of weld metal required. A further consequence of a narrow gap is the high cooling rates leading to strong, tough weld metals. Overmatching of the parent pipe strength by the GMAW weld metal is generally achieved with ease. The disadvantage of mechanised GMAW, with regard to mechanical properties, is the tendency towards high HAZ hardnesses. Careful selection of line pipe composition is required to allow sour service hardness levels to be attained.

Small diameter pipelines have normally been welded with cellulosic electrodes; however new power sources are enabling the re-introduction of semi-automatic and mechanised GMAW. These power sources allow sound roots to be welded with much reduced welder skill levels.

Vertical-down manual welding of pipelines with cellulosic electrodes is a flexible, simple method with a long history, but the process requires good skill levels and does not produce low hydrogen weld metals. Good practices, such as welding the hot pass immediately after the root pass, should be followed. Particular caution needs to be applied if the pipe is high strength (> X60), thick (> 25 mm) or has a rich composition (high carbon equivalent). The quenching of cellulosic welds to allow automatic ultrasonic testing should be avoided. Problems have been encountered with porosity in thin film coatings applied soon after cellulosic welding due to hydrogen evolving from the weld.

Repair welding is invariably undertaken with a handheld process, SMAW (basic and cellulosic) and FCAW (self shielded and gas shielded) being the most common. Repair weld procedure qualification should accurately represent the actual repair welding.

Double jointing is undertaken on the larger vessels. The normal process is submerged arc welding, sometimes with multiple wires. Where the pipe diameter is large enough (approx 18 inch—DN 450) then an internal SAW pass is often made to produce a double-sided weld. On smaller pipe, a few passes are welded using the main line technique before the SAW is applied. For small or thin pipe it is sometime easier to use the main line procedure for the double joint fabrication.

7.5.2.3 Carbon Steel Flow Lines—Onshore Welding

The fabrication of bundles and stalks for reeling use similar welding methods to the offshore techniques discussed in Section 7.5.2.2. The significant difference is that manual GTAW is often used for root welding. Mechanised GMAW is becoming increasingly common for the larger diameters.

As discussed in Section 7.5.1.4, it is necessary to demonstrate that the welds can tolerate the strains experienced when installing pipe by the reel method.

7.5.2.4 Corrosion Resistant Alloy Pipelines

CRA welding techniques are similar to those for carbon steel. Notable differences include:

- application of back purging and control of backing gas oxygen content,
- increased emphasis on prevention of contamination,
- reduced tolerance to pipe misalignment,
- slower welding speeds,
- lower interpass temperatures, and
- possible greater risk of magnetically induced arc blow.

For onshore welded flowlines, the normal techniques are GTAW (for at least the root pass) with SMAW or FCAW for the fill passes, and mechanised GMAW. For offshore welded CRA flowlines, GTAW has been largely supplanted by GMAW. GTAW was preferred for its perceived higher quality; but mechanised GMAW is now the most frequently used process, often in the pulsed mode.

The fill passes of CRA-clad or -lined pipe, i.e. those passes made totally within the carbon steel substrate, can be made with low alloy consumables normally used for carbon steel line pipe, sometimes with an intermediate layer of pure iron deposited above the corrosion resistant weld material. It is, however, more common to weld all passes with a consumable compatible with both the corrosion resistant layer and the carbon steel substrate, and of sufficient strength: typical consumables include 25% Cr superduplex stainless steel, Alloy 625 and Alloy C-276.

The welding of duplex and super-martensitic stainless steels is covered in Appendices III and IV respectively.

7.5.2.5 Alternative Welding Techniques

For many years there has been considerable interest in 'one-shot' or 'one-pass' welding techniques, i.e. where welding is carried out in one operation rather than a series of passes.

Techniques investigated have included electron beam, flash butt, homopolar radial friction and MIAB (magnetically impelled arc butt welding). Such techniques have been successfully demonstrated but, as yet, have not been adopted offshore. One of the problems in justifying the development and installation costs of one-shot welding systems is the continuing improvement being made to conventional mechanised GMAW. For instance, some S-lay barges can now install flowlines at rates of over 8 km per day. At these speeds the welding part of the production cycle is not dominant, and any improvement in welding speed does not yield proportionate increases in productivity. Similarly, there are a number of J-lay vessels installing substantial pipelines using normal multi-pass welding techniques and achieving equivalent lay rates.

Areas of continuing development for GMAW welding include twin wire welding, tandem wire welding, new consumables (e.g. metal cored wires), hybrid processes (e.g. laser and GMAW) and torch tracking (through arc or laser). These developments are largely focused on the welding of trunk lines, but it is probable that the technology will eventually be applied to flowlines.

7.5.2.6 Subsea Tie-Ins

Flowline tie-ins between, for example, flowline and riser, are normally made with flanged connections (see Chapter 9 including recommendations for CRA weld overlay of flange faces and ring grooves). Hyperbaric welded tie-ins are less common, although proven hyperbaric welding procedures exist for both carbon steels and duplex stainless steels. Hyperbaric welding is not feasible for deep water tie-ins, typically exceeding 200 m. Mechanical connectors, other than flanges, are also available and occasionally used.

7.5.3 Plastic-Lined Pipelines

Concern about the problems of bottom-of-line corrosion and the cost of corrective action, including potential damage to a reservoir while any water injection system is off line, has led industry to develop and deploy plastic lined carbon steel for subsea water injection flowlines. This has involved the installation of reeled polyethylene (PE)-lined flowlines in 8 inch to 16 inch sizes (DN 200 to 400). Such lines typically operate at pressures of around 200 bar at ambient temperature.

There are now >200 km of plastic-lined water injection flowlines installed in depths up to 500 m. For these installations, carbon steel pipeline stalks of between 500 and 1500 m are fabricated by normal welding techniques, the length being primarily determined by the spool base. A PE liner of similar length, with an external diameter approximately 2% larger than the internal diameter of the pipe to be lined, is fabricated and pressure tested in the same location. The liner is then pulled through the pipe stalk, the diameter of the liner being reduced by a combination of tension and reduction through rollers or dies at the insertion point. Once the liner is in place, the tension is released, and the liner is allowed to recover (two to three days for PE), resulting in an interference fit against the internal surface of the pipe.

Tie-in connections are then completed before reeling onto the installation vessel. Typically, individual stalks are joined by welding, using pup pieces internally clad with CRA (usually Alloy 625), the pups having been welded to each end of the carbon steel stalks before lining. Once the plastic liner is inserted, the liner ends are mechanically terminated just short of the stalk end. The final tie-in weld does not therefore affect the plastic liner. Several proprietary welding connections have been used, each of which has been subjected to an extensive qualification test programme to prove its fitness for reeling, i.e. combined load testing to simulate reel installation.

The thickness of the liner can be designed either to take full vacuum, e.g. from drawdown by the reservoir, or to take account of the fact that a small defect might in theory exist in the liner, leading to water ingress behind the liner and consequential collapse due to this trapped water being at a higher pressure than the bore fluids further down the line. The latter approach may impose a velocity restriction on the transported fluids, typically around 5 m/s. This design approach is regarded as conservative, given the low likelihood of complete annulus connectivity, and in practice no difficulties have resulted from exceeding these original velocity restrictions in operation, up to around 10 m/s. The ultimate limit is likely to be far higher than this. Most applications have employed medium density PE (MDPE). High density polyethylene (HDPE) is also acceptable for this type of application.

Operational experience over the last ten years has been good. The only reported failure in service occurred where the CRA cladding on an end termination (i.e. remote from the plastic liner) was accidentally ground away during a weld repair. This led to galvanic corrosion and a subsequent leak. This was successfully repaired *in situ*.

Current experience is limited to installation from reel barge, though there is industry activity aimed at extending the technology to S- or J-lay applications. The main issues are cost and speed of installation of connections. Some activity is also underway for rehabilitation of existing subsea lines using PE liners. Although PE lined pipe has only been used subsea for water injection flowlines, hydrocarbon flowlines have been installed onshore using both polyethylene and polyamide 11 (nylon) liners. While this onshore field experience has established that plastic liners prevent corrosion of carbon steel pipe when used for the transport of multiphase hydrocarbons, it has also demonstrated that plain plastic liners have a limited life in production service. The primary failure mode involves the permeation of gases through the plastic liner and accumulation in the annulus between liner and steel host. These gases expand during small depressurisations of the bore, leading to liner collapse. The use of manual vents onshore has proven only partially successful in managing this failure mode. Alternative methods for preventing liner collapse have therefore been under investigation in order to realise the large potential capital and operating cost savings that this technology offers.

Foremost of these alternative methods is a liner in which permeated gases are taken off via grooves on the outside of the liner to a vent in a safe location, i.e. similar in principle to a standard flexible pipe. This design has recently been used in a number of onshore applications, including high pressure, corrosive hydrocarbon systems. Liner design tools, such as groove creep and annulus environment models, together with connection technologies, exist, and are under continuing development around the industry. For offshore application,

engineering of connections and subsea vents has already been undertaken, and the technology is close to commercialisation by at least one installation contractor.

7.6 Risers

7.6.1 General

Materials selection and corrosion control principles for rigid metallic risers, especially vertical designs, are essentially the same as those for flowlines, and in many cases the same materials will be used. Many different designs of risers have evolved as shown in Figure 17, falling into the following broad categories:

- Vertical (or near-vertical) rigid risers for platform-based designs, clamped to the platform structure.
- Vertical rigid risers or bundles for floating production systems which can either be top tensioned or bottom weighted.
- Hybrid risers or bundles, typically comprising a vertical rigid section from the seabed to a subsea buoyancy chamber, then connected to the floating production unit via flexible.
- Steel catenary risers.
- Flexibles from the seabed to the surface.

Flexible pipe is covered in Chapter 10.

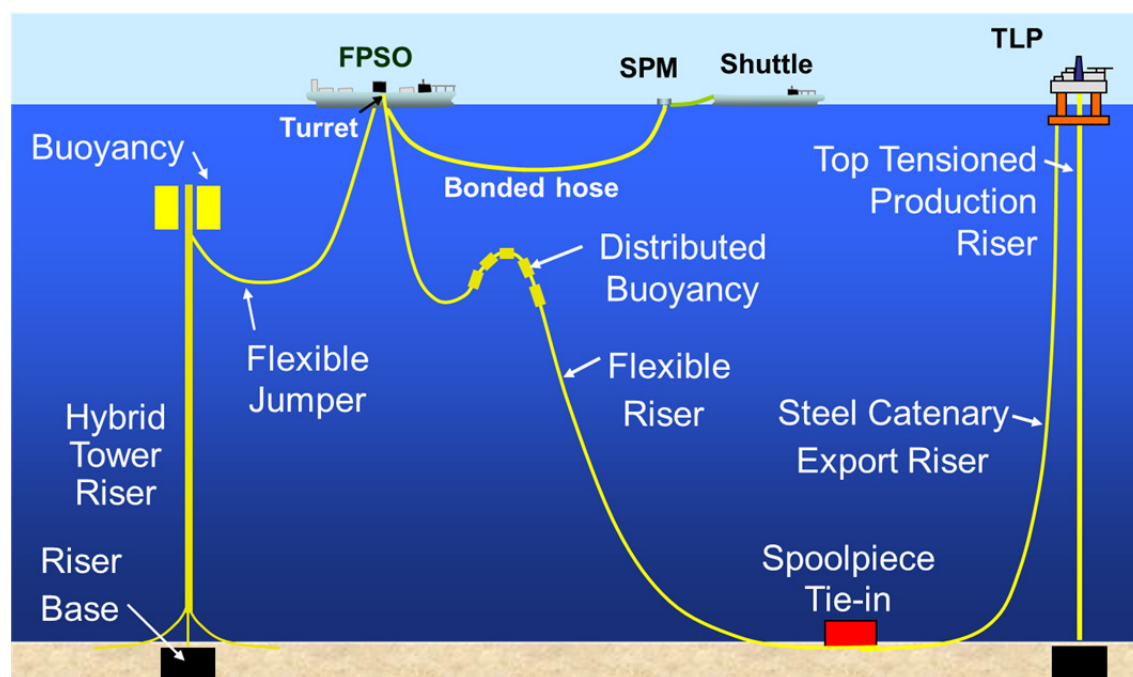


Figure 17 Main riser concepts

7.6.2 Steel Catenary Risers (SCRs)

SCRs are dynamic items whose design is likely to be dominated by fatigue damage considerations, especially when connected to floating production systems. Fatigue damage originates mainly from vessel motions and vortex

induced vibration, and may be exacerbated by internal slugging, pressure cycling and installation.

There are currently two design codes relevant to SCRs: API RP 2RD and DNV OS-F201. These provide recommendations on structural analysis procedures, design guidelines, materials, fabrication, testing and operation. Design needs to take account of the effects of construction and installation operations that may impose permanent deformation and residual loads on the riser system whilst consuming a proportion of the fatigue life. Of particular relevance to the achievement of adequate fatigue performance are girth weld quality, pipe end alignments and out-of-roundness. NDE requirements are likely to be specified from fatigue life and fracture mechanics assessments. The following in particular will need to be specified:

- Stress concentration factors from weld fit-up (hi-lo) limits due to out-of-roundness (for seam welded pipe) and non-uniform wall thickness (for seamless pipe).
- Stress concentrations and residual ovality induced by plastic deformation during installation.
- Weld fatigue class and defect tolerances, especially in the root, as determined by the required fatigue resistance.
- Basis of fatigue or corrosion-fatigue data, i.e. steel in air, freely corroding steel in seawater, cathodically protected steel in seawater, or project-specific data for the expected internal environment.

Steel grade selection and specification will be determined by strength requirements, toughness for fracture and fatigue performance, and sour service resistance as appropriate. Most installed SCRs have been in seamless API 5L X65 type steel, although higher strength grades potentially suitable for SCRs have recently been developed.

Conventional line pipe specifications may need to be supplemented, e.g. by CTOD testing, in order to establish fracture toughness properties in the installed materials. Strain age embrittlement effects for reeled pipelines and risers should be incorporated into the CTOD tests, e.g. by 5% tensile straining followed by heating to around 280°C for one hour. Additional dimensional tolerance requirements will also need to be considered. In the case of seamless pipe, match boring of the pipe ends may be required to achieve suitable ID tolerances, typically ± 1.5 mm over a distance of 100 mm from the pipe ends.

For the fatigue assessment of the weld cap on the outside of the riser, it may be possible to use steel-in-air fatigue data if there is sufficient confidence in the external coating system, otherwise the lower fatigue values for cathodically protected steel should generally be used.

If the riser internal fluids are corrosive, then either a suitably conservative allowance should be made to fatigue design code data, or project-specific corrosion-fatigue data should be developed. In severely corrosive applications where steel risers require very reliable inhibition, consideration may have to be given to internally CRA cladding the regions of maximum fatigue stress, e.g. at the riser top and at the seabed touchdown zone.

SCR attachments to floating production systems are usually made with either 'flex-joints' or 'stress joints'.

Flex-joints are specialised and custom-designed proprietary items incorporating a ball joint and laminated flex element of steel and rubber, and these can cater for relatively large rotations, typically up to 20 degrees. The rubber layers should be designed for shear and/or compression to prevent bond failures and maximise fatigue life. Recommendations for flex-joint elastomers are made in API RP 2RD. A key consideration will be resistance to explosive decompression, especially for high pressure gas duties. A variation on the standard flex joint design incorporates a bellows seal to prevent contact between the gas and the flex element, the annular space being filled with inhibited fluid. This design avoids explosive decompression damage, and can also assist in reducing the operating temperature of the flex element, especially for production risers. The recommended material for the bellows is Alloy 625-LCF (low cycle fatigue grade).

Stress joints are simpler, inspectable, solid metal structures, particularly able to cope with high pressure and temperature. They may be either steel or titanium. They transmit larger loads than flex joints, titanium less so than steel due to its greater flexibility. A typical stress joint would be a flanged spool some 10–15 m in length with tapering wall thickness along the length.

7.6.3 Titanium Risers and Stress Joints

Titanium alloys are stronger, lighter and have lower moduli of elasticity than line pipe steels, and have been used for drilling risers and, more frequently, for taper stress joints on steel catenary risers, as shown in Figure 18.



Figure 18 Titanium alloy taper stress joint for deep water steel catenary riser application

Design is also covered by API RP 2RD, but more specifically by the new DNV RP-F201 which caters for seamless and welded pipe in most commercially available ASTM grades, including 2, 9, 12, 19, 23, 28, 29 and 32. A strong preference for extra low interstitial (ELI) grades is expressed in the DNV RP, and guidance is provided on mechanical, fatigue and fracture toughness properties, corrosion resistance including environmental cracking and liquid metal embrittlement behaviours, wear, weldability, manufacturing procedure specifications, qualification and NDE.

Particular characteristics of high strength titanium alloys for risers and stress joints are:

- relatively low plastic ductility: min UTS/min YS ratio is typically 1.1;
- greater reduction in strength with increasing temperature than steels; and
- very low ductile-to-brittle transition temperatures, below -200°C , for the alpha and alpha-beta alloys.

The most frequently used grades have been ASTM Gr 23 and 29, both of which are Ti-6Al-4V (alpha-beta) with ELI content (see Table 2). Grade 29 contains a small addition of ruthenium for improved corrosion resistance above 80°C . Most applications have been successful. One instance of premature failure of a taper stress joint has been reported, attributed to excessive plastic deformation during installation that led to high strain low cycle fatigue cracking.

8. Valves

8.1 General

Subsea applications include:

- tree valves for main bore and annulus isolation, bore cross-over, flow/pressure control (choke), chemical injection and seal testing;
- manifold and flowline termination assembly valves for isolation and flow diversion;
- hydraulic control system valves;
- chemical injection metering valves;
- pipeline isolation, check and shut-down valves; and
- instrument isolation valves.

Fluids handled include:

- hydrocarbon liquid and gas (produced and re-injected);
- water (produced and re-injected);
- hydrate inhibitor;
- corrosion inhibitor;
- hydraulic control fluid (currently usually water based); and
- brine.

In most cases, valve internals will also come into contact with seawater during installation and commissioning.

Valves for hydraulic control and chemical injection are covered in Chapter 11.

The following valve types are being used in subsea applications: gate (through-conduit slab type and through-conduit expanding (split type)), choke (usually plug and cage, external sleeve or multistage cage types), needle/globe, metering (plunger), check (various types), quarter turn gate and ball (usually trunnion-mounted type).

8.2 Standards

Standards that may be applicable are:

- API Specs 6A, 17D and 14A, and RP 14B;
- ISO 10423, 13628-4, 13628-6, 13628-8 and 14723; and
- ISO 15156/NACE MR0175.

8.3 Materials Options

Materials selection considerations include:

- service temperature and pressure ranges;
- corrosivity and erosivity of fluids contacting valve body and parts;
- abrasion potential of solids (wear on rubbing or sliding surfaces);
- impact potential of solids such as fracking proppants (e.g. on brittle choke components);
- galvanic effects due to proximity between different materials;
- crevice corrosion resistance, e.g. at seal and flange faces;

- galling resistance for moving parts in contact;
- explosive decompression, temperature and chemical resistance for non-metallic materials;
- effect of CP on materials;
- weldability for weld overlaid, welded construction and welded-in valves;
- product form (castings, forgings) and heat treatment condition;
- material availability and cost; and
- effectiveness of coatings.

Metallic materials in use include carbon and low alloy steels, stainless steels (austenitic, martensitic, precipitation strengthened and duplex grades), nickel alloys and beryllium-copper alloys. A welded overlay coating of nickel-base alloy on internally process-wetted parts frequently provides internal corrosion protection of carbon and alloy steels. Non-metallic materials are used extensively for seals. Use is also made of coatings such as cobalt alloys, tungsten carbide and electroless nickel plating (ENP) in parts of the valves to improve sealing integrity or resist wear, galling, erosion or corrosion.

Metallic materials for pressure boundary parts may be limited by the chosen design or product standard since the pressure-temperature ratings of ISO 14723 are only applicable for listed materials. For this reason, materials for tree valves and manifold or pipeline valves frequently differ. Where alternative materials are chosen, there should be a clearly defined and recorded justification for the pressure-temperature ratings being claimed. Details of typical generic materials recommendations are shown in Table 3. Some materials standards relevant to subsea valves are referenced in ISO 14723 and listed in NORSOK Standard M-630.

8.4 Subsea Wellhead Valves to API Specs 6A and 17D

ISO 10423 (API Spec 6A) and ISO 13628-4 (API Spec 17D) list material classes appropriate to service conditions in order of increasing severity. Guidance is given on some production variables (CO_2 partial pressure and sour or non-sour service) that determine each class.

Generic materials that meet the minimum requirements for each material class are listed for bodies, bonnets, flanges, pressure controlling parts and stems. Since wet CO_2 corrosion is a function of factors additional to CO_2 partial pressure, e.g. temperature, pH, etc., corrosion rates should be calculated where possible in accordance with the methods stipulated in Section 3.6.3 to ensure carbon and low alloy steels are adequate for the intended life of the valve.

In view of the logistical problems involved in replacing subsea valves, and the consequences of valve failure, it is recommended that carbon and low alloy steel valves are only used where seat pockets and seal contact surfaces are weld overlaid with stainless steel or nickel alloy.

For sour service, components should meet ISO 15156/NACE MR0175 requirements, and should be used within the limitations stipulated in Section 3.6.2 above. In this context it is important to take into account the effects of hydrostatic pressure and insulating coatings.

An additional factor that determines the suitability of CRAs is resistance to crevice corrosion in warm/hot seawater or oilfield brine. Where any doubt concerning

Table 3 Typical generic valve materials for wellheads, manifolds and flowlines

Component/ Duty	Typical Generic Materials	Notes
Valve Bodies		
Hydrocarbon production	Carbon steels: ASTM A 350, A 352, A 694	Alloy 625 overlay on sealing surfaces or over all process-wetted surfaces dependent on service life and corrosivity of product/chemicals.
	Low alloy steels: AISI 4130/4140/8630, ASTM A 182 F22 (2¼CrMo), other CrMo & NiCrMo alloys	
	Stainless: 13% Cr martensitic e.g. F6NM, 22% Cr duplex & 25% Cr superduplex, austenitic e.g. type 316, super-austenitics e.g. 6% Mo	
	Nickel alloys: UNS N09925/N07718/N06625	
Deaerated sea-water injection	Low alloy steels or carbon steel as above	Alloy 625 overlay on sealing surfaces
	Duplex stainless steel as above	
Aerated sea-water injection	Low alloy or carbon steels as above	Alloy 625 internal overlay throughout
	25% Cr superduplex stainless steel for operating temperatures below about 45°C	
Valve Internals		
Stems	Alloy 718, Alloy 925, 17-4 PH; 22% Cr duplex & 25% Cr superduplex stainless steels; UNS S 20910	17-4PH is not suitable for exposure to raw seawater. It is not recommended for sour service Ref: ISO 15156/NACE MR0175
Seats, gates, balls	Alloy 718, Alloy 625, 22% Cr duplex and 25% Cr superduplex, 17-4 PH, UNS R30035/ R30003/ NI0276	
Springs	Alloy X750, UNS R30035/ R30003	
Gaskets	AISI 316 SS, 6Mo, Alloy 825, Alloy 625.	
Actuators and Gearboxes		
Actuator cylinder and spring housings	Same as for valve bodies	Appropriate corrosion protection to be applied to carbon steel cylinder bores
Torque converter and gearbox housing	Carbon / low alloy steel or ductile iron (spheroidal graphite)	Impact tested at or below minimum design temperature
Actuator springs	Low alloy steel, Alloy 718, Alloy X-750	Adequate protection against seawater ingress important

For valve fasteners/gaskets see Chapter 9.

suitability exists, crevice corrosion testing should be performed in accordance with a recognised standard.

Austenitic steel grades such as 316/316L are susceptible to chloride SCC where the material temperature exceeds about 50°C and oxygen- and chloride-containing water are present. Duplex stainless steels are also affected, though the threshold temperature increases to about 100°C, dependent upon fluid chloride content, temperature, pH and oxygen level (see Section 3.6.4). Oxygen and chloride concentrations in produced hydrocarbons subsea are usually too low to give rise to this problem. Where oxygen may be introduced locally as a result of raw seawater ingress or glycol/methanol injection, or where brines are very concentrated, consideration should be given to the use of nickel alloys resistant to chloride SCC.

Where fluid erosivity is a factor, e.g. in sand service or where proppant flow-back occurs, material selection for the internal surfaces of pressure boundary parts should follow the practice adopted for flowlines, etc. Where unusually high local fluid velocities are expected, e.g. in the outlet ports of choke valves, special measures, such as the fitting of erosion resistant inserts, may be necessary. Isolation valves should always be specified with hard, abrasion resistant internal trim coatings such as tungsten carbide. Choke valve trims should also always be specified in highly erosion resistant material such as sintered tungsten carbide.

Verification testing of material suitability should be performed in accordance with the requirements of ISO 10423 or API Spec 6A (see Section 8.6). It may be unnecessary to perform verification testing if erosion resistant materials such as tungsten carbide are used. The operability of valves may also be affected by sand, internal screw gate valves being particularly vulnerable to both the clogging effects of accumulated sand and wear of the screw thread mechanism.

Broad compositional maxima are listed in API Spec 6A for body, bonnet, inlet and outlet connections. Dependent upon specific service conditions, e.g. sour, low temperature, etc., it may be necessary to limit elements such as sulphur, phosphorous, carbon, vanadium, nickel, etc., still further. Guidance on compositional restrictions for sour service is detailed in documents referenced in Section 3.6.2 above. Reference should also be made to Section 8.9 below if valves are to undergo any welding.

8.5 Pipeline, Subsea Manifold and Flowline Valves

ISO 14723 refers to ASME B16.34 which lists materials suitable for pipeline, manifold and flowline valves of Class 2500 rating and lower. Other materials such as high nickel alloys are not precluded from use.

The same selection criteria listed in Section 8.4 above apply, as do the methodologies detailed in Section 3.6 above for evaluating wet CO₂ corrosion, erosion service suitability, sour service requirements and limitations, chloride SCC, and crevice corrosion resistance. In particular, it is recommended that carbon and low alloy steel valves are always provided with Alloy 625 overlaid seat pockets and seal contact areas.

Where design pressure exceeds the limits of ASME Class 2500, it is likely that the valve design will be required to conform to ISO 13628-4, etc., and the material requirements of those standards should generally be met. Where the piping design code is ASME B31.3, the allowable stress limits of that standard should be applied. For valve shells made from duplex stainless steels it is recommended that allowable stress intensity should be established using both yield and ultimate

stress criteria in order to avoid dimensional instability by 'cold creep' (see Appendix III).

8.6 Erosion and Wear Resistant Materials

8.6.1 Introduction

Erosion as a result of attrition by hard particles or liquid droplets is unlikely in the case of full bore isolation valves if material selections follow the recommendations of an erosion study performed for adjacent piping, etc. Choke valves may well suffer from this phenomenon as well as from cavitation erosion in predominantly liquid flow streams where very high local pressure drops are unavoidable. In the case of isolation valves, wear and scoring of components in sliding contact is the most likely result of erosive conditions.

Where sand is not predicted, cast, weld-deposited or thermally sprayed cobalt-based alloys will normally be adequate for valve trim. However, the presence of sand can rarely be accurately predicted, and a conservative approach towards the use of harder materials is recommended.

Erosion resistance of materials will vary widely as a result of local conditions (angle of impingement, etc.) but, as a rule of thumb, the following materials have increasing erosion resistance in the order listed:

- cobalt alloy 6,
- cobalt alloy 1,
- partially stabilised zirconia,
- tungsten carbide (with 5 to 7% Co binder), and
- sintered silicon carbide.

Other materials that have exhibited good resistance to erosion/corrosion conditions in testing (warm seawater/sand), but for which there is limited reported service experience are:

- diffusion coatings of chromium and boron–chromium,
- thermally sprayed sintered coatings of nickel 17%Cr 3.5%B Si Fe C, and nickel 16%Cr 4%B 4%Si 3%Mo Fe Cu C.

Chemical vapour deposition (CVD) or physical vapour deposition (PVD) thin diamond coatings applied on top of tungsten carbide have been shown in laboratory tests to offer benefits of reduced (and more consistent) coefficient of friction as well as longer life which could be of benefit in very high pressure applications.

8.6.2 Carbide Coatings

Tungsten carbide should be specified at critical locations instead of cobalt-base alloys where optimum erosion or wear resistance is desired. Nowadays virtually all subsea gate and ball valves use carbide coatings at the primary shut-off interface, and choke valves use trim components manufactured from solid, sintered carbide. All carbide formulations, whether sprayed or sintered, use a metal matrix to bind the carbide particles together. This is nearly always cobalt-base or nickel-base, and can affect the material's resistance to both corrosion–erosion and galvanic corrosion (the carbide particles are largely inert).

The latter is a particular consideration where carbide coatings may come into contact with water-based control fluid (e.g. where a coated valve stem extends into an actuator containing more noble materials). Carbide grain size has a significant effect on erosion resistance such that sintered material comprising grains of under 1 μm can have twice the erosion resistance of material containing grains up to 5 or 6 μm . However, the increased erosion resistance may be achieved at the expense of toughness, so sintered components should ideally be mechanically supported by ductile material. Where an ideal balance of properties cannot be achieved, a choice will often have to be made between maximising erosion resistance and maintaining the ability to withstand impacts.

The percentage of cobalt binder also has an effect since the binder can be preferentially attacked. Levels around 5 to 7% seem to give an optimum balance of erosion resistance and corrosion resistance. Data indicates that alloying the cobalt matrix in tungsten carbide coatings with around 4% chromium significantly reduces the loss due to corrosion in erosive and/or corrosive media. Pure chromium and nickel binders should be avoided, however.

Various techniques can be used to apply tungsten carbide coatings, including HVOF (high velocity oxy-fuel), plasma (several methods), and detonation flame spraying. The different techniques result in various degrees of porosity, and filling with epoxy resin has traditionally been used to ensure acceptable performance, e.g. of valve seats and gates on gas service where the gas can migrate through the pores in the coating and prevent acceptably tight shut-off from being achieved. Nowadays, the better HVOF techniques can achieve acceptable results without the need for a resin fill — an important consideration where elevated temperatures may be experienced. There are no national standards/specifications or acceptance criteria covering application by these techniques, and application should be in accordance with a procedure agreed with the valve manufacturer. The following requirements are typically specified, but end users should satisfy themselves that the intended service life will be achieved for the particular duty:

- Machine surface prior to coating to an agreed roughness (typically about 0.8 μm).
- Degrease surface. Heat to about 60 to 90°C or higher, and grit blast while warm. Remove blast residue before spraying. Coat while still warm to an agreed minimum thickness (typically about 150 μm).
- Seal coated surfaces with an agreed sealer where necessary (block valves only). Lap surface to an agreed quality, typically a maximum roughness of about 0.15 μm .
- Minimum bond/adhesion strength should be tested in accordance with a standard such as ISO 4624 and should achieve a minimum strength of, typically, 70 MPa (10,000 lbf/in²).
- A 180 degree bend test should be performed and no spalling should result.
- Porosity test by metallography and liquid penetrant examination to give zero indication or as otherwise agreed (typical values offered by applicators are between 0.5 and 1.0% by volume). Note that the ultimate test for porosity is a gas seat test on the valve.
- Minimum hardness check (typically a minimum of 1000 Hv but ranging up to 1350 Hv).

Because carbide coatings are brittle, it will be necessary to demonstrate that, where they are likely to be subject to high strain (e.g. on the seats of ball valves

closing against high differential pressure), this can be accommodated without cracking of the carbide coating.

8.6.3 Electroless Nickel (ENP) and Hard Chromium Platings

ENP and hard chromium coating of components can provide limited wear resistance and prevent galling, but neither should be used as a means of preventing long term corrosion, particularly chromium plating whose significant porosity will promote pitting. ENP coatings can contain varying levels of porosity dependent upon formulation of the ENP solution, substrate porosity, and surface condition and pre-treatment of the component. NACE Report 6A194 gives information on pre-treatment. Typically, properly controlled, Ni-11P ENP is largely free of porosity.

ENP is frequently applied to the balls of soft seated ball valves where it provides wear resistance, but the thinness of plating means that it is ineffective where abrasive conditions exist. It should not be used in subsea applications to provide corrosion resistance to carbon or low alloy steel components.

The properties of ENP vary considerably depending upon composition, processing and post-application heat treatment. NACE Report 6A287 (1997 revision) gives information on three grades of nickel-phosphorous and two grades of nickel-boron ENP coatings. The procedure and testing should be agreed with the valve manufacturer. For most applications a coating containing approximately 11% phosphorous (grade Ni-11P) is used.

High hardness ENP is less corrosion resistant than low hardness ENP, therefore selection is dependent upon specific functional requirements and the operating environment. Non-heat treated Ni-11P has the best corrosion resistance, but the hardness is about 550 to 600 Hv which is considerably lower than the 950 to 1100 Hv obtained by heat treating at between 350 and 380°C, and heat treated Ni-11P still exhibits reasonable corrosion resistance, see NACE Report 6A287. The same document advises that when the hardness of the ENP exceeds about 850 to 900 Hv, micro-cracking of the coating is possible, which can lead to galvanic corrosion of carbon and low alloy substrates in media that support this corrosion mechanism. On liquid hydrocarbon service such corrosion is usually suppressed. Stainless steels are nobler than the ENP, so galvanic corrosion does not occur beneath such discontinuities when ENP is applied on top of corrosion resistant alloys.

Typical requirements specified to ensure ENP quality are:

- Tests, or analytical data based on tests, that the materials or coatings for any surfaces exposed to erosion meet the design requirements for the specified service life. ISO 10420 is a suitable reference standard for testing.
- Adhesion of ENP to carbon, low alloy and stainless steels is good. Bond strengths are typically 200 to 420 MPa for carbon and low alloy steels, and 160 to 200 MPa for stainless steels.
- Thickness is as specified.
- Porosity is within agreed limits. Information on porosity testing is given in NACE Report 6A294.
- Hardness testing to ensure specified values are met. Information on hardness testing of ENP is also given in NACE Report 6A294.

8.7 Weld Overlaying of Duplex Stainless Steels

Where duplex or superduplex stainless steels are to be weld overlaid with cobalt-based hard-facing material or Alloy 625, the weld procedure qualification should demonstrate that the substrate under or adjacent to the overlay is free from sigma and other embrittling phases, and that the corrosion resistance is not impaired. In the case of Alloy 625 weld overlays, e.g. for increased crevice corrosion resistance at joint faces, niobium-free consumables should be considered in order to avoid nitrogen depletion of the duplex stainless steel.

Hard facing by weld overlaying may involve high levels of heat input that may impair material properties, particularly in 25% Cr superduplex grades and is best avoided.

8.8 Valve Internals—Metallic

The operating conditions of valves will sometimes be benign compared with the conditions that they may experience during installation, testing or subsea intervention. Internal components of valves should therefore generally be selected to be fully corrosion resistant in all these circumstances.

Corrosion related problems in valves can arise because of poor sealing/seating allowing corrosive fluids to contact valve components supposedly separated from them, e.g. raw sea water ingress into valves or passage/entrapment of fluids used for testing. This situation should be anticipated and catered for in valve design and materials selection.

Contact between different materials exposed to untreated or inadequately treated seawater or test fluids can lead to galvanic corrosion of the less noble material. Such problems have occurred with materials such as Alloys 718 and X750 when in contact with Alloy 625. These materials are frequently used in combination in valves. If seawater becomes trapped around the components during subsea maintenance activities (e.g. actuator change-out), the need to flush the cavity with a benign fluid after closure should be considered.

For metal-to-metal seals or seal housing exposed to raw seawater without CP, CRAs such as Alloys 625, C-276, UNS R30003 (AMS 5833) and R30035 (AMS 5834) should be used.

Modern water-based synthetic hydraulic fluids may have unexpected effects on metallic materials and coatings, so where there is contact, testing to confirm compatibility with the actual formulation should be undertaken.

Adequate hardness differential between contacting metallic faces helps avoid galling. A hardness differential of 30–40 HB is recommended (note that this does not apply to carbide coatings). In cases where extensive use is made of duplex or other stainless steels of the same grade, surface coatings/plating may be necessary to achieve this differential.

8.9 Valve Internals—Non-Metallic

Non-metallic seals, bearings and seat inserts are used extensively in valves.

Graphite packing and seat/seal materials (irrespective of whether or not they are 'inhibited') are best avoided in subsea valves, particularly where exposure to seawater is possible, because of their potential to cause galvanic corrosion.

Ball valves having thermoplastic or elastomer seat inserts are sometimes specified where the system designer is confident that they will not suffer damage as a result of testing, line clearing/de-watering or service conditions. Common thermoplastics are PTFE (virgin and filled), acetals (e.g. Delrin), polyamides (Nylon), PEEK (polyether ether ketone, e.g. Victrex, Arlon), and PPS (polyphenylene sulphide, e.g. Ryton).

In addition to their sensitivity to abrasives and solid objects, these materials all have limitations. Many are more limited by temperature than by chemical environment, and the pressure rating at elevated temperatures can therefore be reduced. Polyamide materials are hygroscopic and can then become brittle at elevated temperature. Since contact with seawater will usually be inevitable at some stage this material should not be specified for application at temperatures above 100°C.

The manufacturer's pressure-temperature ratings for non-metallic seats should be obtained, and general suitability for the service confirmed.

Stem and body seals of all valve types will also frequently employ thermoplastics, most usually filled grades of PTFE in a mechanical or pressure energised sealing arrangement. The filler increases rigidity at elevated temperatures so that, with appropriate design and containment, temperatures up to 200°C can be accommodated. PEEK is frequently used as a seal support or housing and this has even higher temperature capabilities. Nevertheless, the upper temperature limit of such seals will always be influenced by the maximum operating/design pressure, and very high pressures will tend to reduce this as well as increasing the risk of extrusion damage.

Stem and body seals often include elastomer materials such as nitrile rubber (NBR), FPM fluoroelastomers (e.g. Viton, Fluorel), hydrogenated nitriles (HNBR) and, less commonly, TFE/P fluoroelastomers (e.g. Aflas) and FFKM perfluoroelastomers (e.g. Chemraz, Kalrez).

In the case of elastomers, the limitations can be both physical and chemical, for example:

- All elastomers have temperature limitations. For O-ring type seals, nitriles should never be used above 120°C, whilst FPM fluoroelastomers, such as Viton, can function up to 200°C.
- The low temperature limit is often even more restrictive, particularly when combined with a requirement for explosive decompression resistance (e.g. in gas service), and is very grade dependent. Generally, HNBR will have a lower limit than NBR and FPM elastomers, but there are no useful elastomeric materials which can function with gaseous hydrocarbons at temperatures below -45°C. Elastomers will withstand exposure to low

temperature transients without suffering permanent damage, but the problem is such that where they are employed low temperature requirements need to be considered in detail and defined as accurately as possible. Simply specifying the minimum design temperature as the standard impact test temperature of the valve body or pipe material, for example, should be avoided; a more realistic assessment of minimum temperatures should be made and applied.

- Concentrated methanol can cause FPM fluoroelastomers such as Viton to swell unacceptably. The effect is dependent on the grade of Viton but is greatly mitigated by the presence of even a small quantity of water, such that given a water content of 2%, Viton B materials are unaffected.
- Nitrile and TFE/P fluoroelastomer materials such as Aflas are degraded where there is a high aromatics (benzene, xylene, toluene) content in the process fluids.
- The suitability of specific elastomers for use in H₂S service should be established by testing or service experience.
- For high pressure applications, O-ring seals should include filled PTFE or PEEK anti-extrusion back-up rings where the possibility of extrusion cannot be excluded by control of housing dimensions and tolerances alone.
- In dry gas service, elastomers need to be selected to take account of expected decompression rates. Where these are other than very slow (e.g. blowing down a long pipeline), the possibility of explosive decompression damage will exist. Since this is cumulative it may only make its presence felt (as leakage) after a number of years of operation. At pressures below 70 bar nitrile will usually be resistant. At higher operating pressures, filled grades of FPM and HNBR are available having good resistance obtained at the expense of impaired mechanical properties. Experience shows that there are very few elastomers that have acceptable resistance, and all of these have restricted low temperature capability. Tests on actual seals in realistic housings after a prolonged exposure to high pressure (e.g. 48 hours or more) at operating temperature is the only way to gain confidence in a material's resistance to explosive decompression. Elastomer seals of larger cross section tend to contain manufacturing defects that precipitate cracks, regardless of the formulation.

Suitability of elastomers for the pressure, temperature and fluid for any given service should be confirmed. In this respect, any excessively conservative assumptions made by process designers may need to be challenged: detailed definition of requirements is essential.

Product verification testing of subsea valves, generally in accordance with API Spec 6A Appendix F to Performance Requirement Level 2 (PR2), is recommended to establish general suitability, leak tightness, and compatibility of materials through the temperature range. Depending on operating requirements, additional testing (e.g. endurance cycles, individual seal performance tests, reverse pressure withstand tests) may be advisable. Owing to the consequences of failure, such testing should always be insisted upon except where there is a proven track record in the application, and the technology is mature. Paragraph

F1.14 of API 6A applies to non-metallic seals, and the guidelines contained in NORSOK Standard M-710 may also be useful for confirming non-metallic material suitability. The section covering rapid decompression is of particular relevance. It should be noted that initial soak times in decompression tests may need to be as long as 14 days to achieve saturation.

The performance of sealing systems, especially at high pressures/temperatures, is as much a function of design as materials selection. Testing or service experience under realistic conditions is vital.

ISO 23936 series provides guidelines for selection and qualification for some non-metallic sealing materials.

8.10 Material Specifications and Testing

8.10.1 General Requirements

All materials for subsea valves and components should be covered by a recognised standard or a written material specification giving requirements for chemical composition, melting and manufacturing practice, mechanical testing, any applicable special testing (chemical resistance, metallography, corrosion testing, etc.), heat treatment, and non-destructive testing.

Elevated temperature tensile testing should be performed where the design temperature is above the range for which allowable stresses are listed for the material in the applicable reference code. This should include welds.

For subsea wellhead valves, the quality level should be at least API Spec 6A PSL3 unless lower integrity can be justified.

8.10.2 Valve Shell

For tree valves where size is limited and use of duplex stainless steels unusual, manufacture by forging is generally preferred for reasons of material integrity. Manifold and pipeline valves, however, are frequently of larger diameter, and here cast construction can offer advantages of weight and cost saving, especially where operating pressures are high. Duplex stainless steel castings also reduce the problems of achieving adequate quenching rates associated with heavy section forgings. In this case, however, it is important to limit design stresses if the phenomenon of 'cold creep' and associated dimensional instability is to be avoided. Adequate assurance of casting soundness and achievement of required mechanical properties should be demonstrated in all cases by the use of non-destructive and destructive testing. Strict control of defect repair is recommended using a written procedure that limits the extent and nature of defects, and specifies post repair heat treatment and NDT.

8.10.3 Hardness

All materials and welds exposed to sour process fluids should be shown to meet the hardness requirements of ISO 15156/NACE MR0175. The requirements of applicable standards such as API Spec 6A should also be met. Hardness differentials necessary for sealing surfaces or to avoid galling should be demonstrated.

8.10.4 Impact Properties

For subsea wellhead valves the minimum requirements specified by API Spec 6A appropriate to the temperature classification of the valve should be met. However, for maximum assurance against brittle fracture the acceptance criteria recommended in Table 4 below may be used to supplement the requirements specified in API Spec 6A.

Table 4 Recommended Charpy impact test requirements for subsea wellhead valves

Material	Impact Energy (J)	
	Min. average	Min. individual
Carbon and low alloy steels	40	30
ASTM A182 F6NM	40	30
17-4 PH (UNS S17400) (valve internals)	40	30
22% Cr duplex stainless steel	45	34
25% Cr superduplex stainless steel	55	41
Other materials (which exhibit reduced toughness at low temperatures)	Per applicable standards/codes	

Testing should be at the temperature specified by the relevant design code or 0°C, whichever is the lower.

The same acceptance criteria should also be used for manifold and flowline valves. However, the minimum requirements should meet the applicable codes and standards, and average Charpy energy values in joules should generally meet or exceed the specified minimum yield strength in MPa divided by 10.

8.10.5 Welding for Valve Fabrication and Installation

Base material composition should be controlled to give good weldability. Where necessary, base material weldability trials should be performed. In general for carbon steel materials the following limitations are recommended:

- carbon 0.23 wt % maximum, and
- IIW carbon equivalent 0.45 wt % maximum.

Welding should be performed in accordance with a welding procedure that has been qualified by testing in accordance with the referenced codes/standards. Where no codes / standards are referenced, testing to ASME IX or ISO 15614-1 is recommended. Discretion should be exercised in how materials are categorised for weld procedure qualification because of anomalies in the way different materials are grouped together for this purpose. When in doubt, it is safest to insist on a qualification based on the actual material specifications to be joined. Small fillet or seal welds on thick sections can lead to high hardnesses and subsequent cracking, and therefore require representative welding procedure qualification rather than being based on a butt weld as permitted by the codes.

Welds should be subjected to the same tests as base materials. Weld and, where necessary, heat affected zone properties should match those of the base materials in respect of strength, hardness, Charpy toughness and corrosion resistance. Overlays should meet acceptance criteria agreed with the manufacturer.

9. Fasteners and Gaskets

9.1 Introduction

This Chapter describes the selection of material for fasteners on subsea equipment, and the precautions required for their use. Included in this description are threaded connectors (studding, bolting, cap screws), other forms of connectors (such as clamps and circlips), metallic sealing rings, and non-metallic seals.

9.2 Threaded Connectors

9.2.1 Scope

Threaded connectors include bolts and nuts for flanged connections (ASME, API and compact), bolts threaded directly into components (e.g. for valve bonnets and instrument connections), bolts for tightening clamps (e.g. hub connector clamps and pipe support clamps), and cap screws. Low alloy steel and CRAs are considered.

9.2.2 Low Alloy Steel Bolting

9.2.2.1 Materials

The low alloy steel bolting material used for subsea connections conforms, almost universally, to either ASTM A 193 Gr. B7/B7M or, where low temperature impact testing is required, to ASTM A 320 Gr. L7/L7M or Gr L43. (Grade L7 is typically specified for diameters up to 50 mm, Grade L43 for diameters up to 100 mm). The corresponding nut materials for B7/B7M bolting are ASTM A 194 Gr. 2H/2HM (C-Mn steel) or Gr. 7/7M (low alloy steel). Where the above A 320 bolting grades are specified, Gr. 7/7M nuts with S3 (low temperature) supplementary requirements are used. These materials are not corrosion resistant, and in a subsea environment require CP.

9.2.2.2 Applications

It is now generally accepted that where low alloy bolting is used for conventional flanged connections in C-Mn steels, CP from remote sacrificial anodes is effective over the full length of the bolt. Operating experience for a range of flange configurations confirms that an adequate protection potential is maintained in the crevice formed by the bolt and flange bolthole. The former practice of sealing the bolts, bolt holes and space between the flanges from the external environment using flange protectors and bolt end caps (with injection of grease into the cavities so formed) is now considered unnecessary. In fact, the use of flange protectors is now thought potentially hazardous, as, if there is partial leakage of the grease and replacement by seawater, the flange protector may shield the bolts and external surface of the gasket from the CP.

Until recently, it was generally assumed that, due to the combined effect of geometry and galvanic incompatibility, CP could not provide sufficient protection to low alloy flange bolting if used in CRA flanges, and that corrosion would occur within the crevice. This assumption has now been questioned in the light of trials and finite element studies. Low alloy steel bolting is now generally used for connections in duplex and superduplex stainless steel subsea piping. Again, the

use of flange protectors and bolt end caps is now considered to be potentially hazardous and is not recommended.

Low alloy bolting is normally used where threaded directly into a carbon or low alloy component, provided the assembly is under CP. Bolting for carbon and low alloy steel clamps is, almost universally, in low alloy steel.

Low alloy bolting has also been used where threaded directly into CRA items (again, under CP), although CRA bolting is often preferred in this application. Bolts screwed into component bodies should be of a material that is compatible with the body with respect to galling and ability to disassemble the component for maintenance, if relevant. The possibility for galvanic corrosion and the consequences of different thermal coefficients, if relevant, should be considered when dissimilar metals are used in bolts and components.

9.2.2.3 CP of Low Alloy Bolting

As stated above, the safe use of low alloy bolting subsea is dependent on effective CP. Factors affecting CP are:

- **Partial immersion.** CP is only effective where the bolting is fully immersed, and there is an electrical path through the water between the bolting and the anode. Corrosion will occur where immersion is not continuous (e.g. in splash zones or tidal conditions).
- **Geometry.** The cathodic potential at any point is dependent on the distance from the sacrificial anode, the length and width of crevices, and design features causing shielding of the current through the water.
- **Temperature.** Increasing temperature will raise the cathodic current density, reducing the achieved potential, particularly within crevices.
- **Coating.** Effective external coatings will reduce overall anode current demand, facilitating the achievement of adequate, negative potentials in crevices. However, thick, non-continuous coatings, such as disbanded thermal insulation, can shield CP.
- **Parent material.** Uncoated CRA materials will increase cathode current and hence hinder the achievement of adequate, negative potentials in crevices.
- **Burial.** Immersion of the connection in mud or silt will reduce the cathodic potential, and if anaerobic conditions exist may increase the potential required for CP.

It is recommended that the above factors be considered before low alloy bolting is selected, and should the conditions be outside previous experience, the effectiveness of CP be investigated by finite element analysis or direct experiment.

As discussed in Chapter 4, CP can cause hydrogen embrittlement of low alloy steels with susceptible microstructures. For this reason, it is preferable to specify bolting and nut materials with the 'M' designation (e.g. B7M, L7M, 2HM), limiting the hardness of the material to 22 HRC. Should the design strength of such bolts be inadequate, higher maximum hardness limits may be specified. B7 material has been shown to be resistant to embrittlement at a hardness of 34 HRC, and this maximum hardness is permitted by ISO 13628-1. ISO 21457 permits a maximum hardness of 35 HRC, and additionally specifies that the actual yield strength should not exceed 950 MPa.

9.2.2.4 Coating of Low Alloy Bolting

The coating of low alloy bolting materials protected by CP is unnecessary. However, thin metal (hot spun galvanised or zinc-nickel electroplate) or PTFE coatings are often specified to preserve the bolt surface prior to installation and, with the latter material, to aid assembly. Hydrogen bake-out heat treatments are not considered necessary for electroplated steel fasteners of maximum hardness 34 HRC. ISO 4042 also relates the risk of hydrogen embrittlement of electroplated fasteners to hardness, the threshold being slightly lower at 320 HV (32 HRC).

If a PTFE coating is used, care needs to be taken to ensure electrical continuity between the bolting and the assembly and is, therefore, not recommended. Cadmium plating should not be used.

9.2.3 CRA Bolting

9.2.3.1 Reasons for Use

CRA bolting is used in any situation where, due to the factors stated above, the CP of low alloy bolting would be considered inadequate. Typical examples of this are bolts in splash zones and, until recently, bolting on CRA flanges. Alternatively, where particularly high stresses and bending moments on flanged joints are present, titanium alloys may be specified on account of their combination of high strength and low elastic modulus properties.

9.2.3.2 Materials

The following CRAs have been used for bolting:

- precipitation hardened cupro-nickel (e.g. UNS C72420);
- 25% Cr duplex stainless steels (e.g. UNS S32750, S32760);
- precipitation hardened nickel-copper alloys (e.g. Alloy K500);
- high nickel alloys (e.g. Alloys 625, 718);
- austenitic stainless steels (ASTM A 193 Gr. B8, AISI Type 316);
- precipitation hardened austenitic steel (ASTM A 453 Gr. 660), with UNS S21800 nuts; and
- titanium alloys (ASTM Grades 5, 19, 23, 29).

A pitting index (PREN/PREw) of 40 or greater is normally considered a requirement for immunity from pitting and crevice corrosion for stainless steels in aerated seawater at ambient temperature (20°C).

9.2.3.3 Hydrogen Embrittlement (HE) of CRA Bolting

Most of the materials listed above have exhibited HE when exposed to CP, at least under laboratory conditions. Embrittlement is pronounced at potentials more negative than about -900 mV (Ag/AgCl/seawater). Failures in service ascribed to CP, have been reported in Alloy K500, 25% Cr duplex stainless steel and alloy 625, although faulty heat treatments may have been a contributory factor. Of the above materials, only precipitation hardened cupro-nickel and precipitation hardened austenitic steel have been found to be totally immune to hydrogen embrittlement, although the susceptibility of the other alloys is extremely

dependent on the metallurgical condition. This susceptibility, together with other properties of the CRAs, is discussed in Section 9.2.3.4.

9.2.3.4 Specific Material Properties

a) Precipitation hardened cupro-nickel (e.g. UNS C72420)

The advantages of this material type are:

- it is one of the few that does not exhibit HE under CP,
- some grades can be heat treated to the same strength as B7,
- it is fully corrosion resistant in sea water,
- good machinability, and
- good resistance to marine growth and galling.

The main disadvantage is:

- proprietary materials with limited supply base

Several service failures occurred some years ago with one proprietary bolting material of this type. These were attributed to SCC in the presence of sulphides, amines and ammonia (which can occur in lubricants). Susceptibility to SCC at 50°C in seawater, if not under CP, has also been reported. These service failures resulted in a reluctance to use this particular material.

The more recently introduced grade shown in Table 2 (Section 3.5) has shown no susceptibility to SCC in laboratory tests, and so far has an unblemished track record in both splash zone and fully immersed subsea service. The specification for its supply can include room temperature slow strain rate batch testing to NACE TM0198 in saturated ammonium chloride.

b) 25% Duplex stainless steels (e.g. UNS S32550, S32750, S32760)

The advantages of these and similar grades of superduplex stainless steels as bolting materials are:

- Strength levels up to Gr. 7M (yield strength 600 MPa) with good ductility and low yield/UTS ratio (< 0.75) in the solution treated condition. (Work or precipitation hardening can achieve higher strengths, but this is not recommended if the bolting is to be exposed to CP — see below.)
- Complete corrosion resistance to seawater (up to at least 30°C), with PREN/PREw values ≥ 40 .
- General availability and simple heat treatment.

The main disadvantage is susceptibility to HE under CP, which appears to increase with the degree of precipitation hardening, although some level of embrittlement will occur in all stainless steels. The following precautions are recommended if these steels are to be used for bolting:

- Duplex stainless steels should be in the solution treated condition (superduplex stainless steels such as S32750 and S32760 can achieve the equivalent strength to A193 Gr. B7M. in this condition).
- The hardness should be limited to 280 HB (28 HRC).

- Materials should be impact tested to demonstrate freedom from precipitation (80 J at -50°C is recommended).
- Bolt threads should be formed by rolling (to induce compressive stress in thread roots).

c) Precipitation hardened nickel copper

Bolts in this material (K500) have failed in service by HE from CP. Most of these failures were associated with over-ageing. Although susceptibility to HE can be reduced by correct heat treatment, it cannot be eliminated. There has been little recent use of Alloy K500 since the above failures, despite better understood metallurgy.

d) High nickel alloys

Alloy 625 has been used as CRA bolting material. It has moderate strength in the solution treated condition (YS 450 MPa) and complete resistance to seawater corrosion (PREN > 45). Higher yield strengths, up to at least 725 MPa, may be achieved by precipitation hardening. It is costly and difficult to machine. Alloy 718 has high strength (YS > 1000 MPa in the precipitation hardened condition), but with a PREN of only 26–30 cannot be considered fully corrosion resistant in seawater.

Both alloys have exhibited HE under CP in the laboratory, and a service failure has been recorded in Alloy 625 bolting which had been precipitation hardened to a yield strength of over 950 MPa. It is recommended that a hardness limit of 35 HRC be applied to both materials if exposed to CP (although higher limits, e.g. 40 HRC may be considered for Alloy 718). If possible, Alloy 625 should be used in the solution treated condition.

e) Austenitic stainless steels (Grades S304, S316)

ASTM A 193 Grades B8 (S304) and B8M (S316), both Class 1 and 2, are not normally used for high pressure pipeline or manifold flanged bolting due to their low strength (SMYS 380 MPa). Strain aged grades of these materials exist, e.g. Grade B8 Class 3 with a SMYS of 665 MPa, but there is no experience of their use subsea.

Grade B8 and B8M bolts are normally used for subsidiary connections on, for example, instruments, hydraulics and brackets. Due to the low PREN (about 20 for B8 and 26 for B8M), these materials are not fully corrosion resistant to seawater and require effective CP. The high sulphur or selenium free-cutting grades, Grades B8F and B8FA, have particularly low corrosion resistance in seawater and should be avoided.

f) Precipitation hardened austenitic stainless steels

ASTM A 453 Gr. 660, a precipitation hardened austenitic stainless steel, has been used as a subsea bolting material. Its strength is equivalent to A 193 Gr. L7M material, and it has been found, by experiment, to be immune to HE. The material is of relatively low corrosion resistance however (PREN can be lower than type 304 SS material) and would require CP. The heat treatment is relatively complex, and the A 453 standard does not recommend this material for general use.

g) Titanium

Titanium alloys may be considered immune to all forms of corrosion by seawater below about 80°C, and some of the alloyed grades (e.g. 12 and 29) are immune to at least 200°C. The higher strength alpha-beta alloys (UNS R56400, ASTM Gr. 5, and UNS R56407, ASTM Gr 23) and beta alloys (UNS R58640, ASTM Gr 19) achieve yield strengths over 750 MPa in the annealed condition, and may be heat treated to strengths in excess of 1000 MPa. All these alloys have been used to a limited extent for bolting in marine environments, mainly for titanium flanged joints and taper stress joints on risers.

Titanium alloys have exhibited HE by hydriding, especially when galvanically coupled with less noble materials such as carbon steel. The beta and alpha-beta alloys appear significantly less sensitive than the lower strength, alpha alloys. Nevertheless, long term exposure of highly stressed titanium alloys to CP does represent a concern even though no service failures due to HE have been reported to date.

Caution should therefore be exercised if titanium alloy bolting materials are to be used in systems subject to CP. ISO 21457 also recommends avoiding exposure of titanium alloys to cathodic protection. Good practice is to independently electrically isolate titanium studs from CP systems by the use of insulating sleeves, ceramic washers or ceramic-coated nut faces (e.g. by alumina or alumina-titania plasma spray). Anodising has also been used to reduce hydrogen absorption and may be particularly beneficial where electrical isolation from CP systems cannot be assured.

Note: Where steel studs and nuts are used for a bimetallic steel-titanium flanged joint, the studs should be electrically isolated from the titanium side by ceramic washers or ceramic-coated nut faces, but should be electrically continuous with the steel side to ensure receipt of CP.

9.2.3.5 Galling

Galling is the binding of threaded surfaces, effectively localised friction welding, causing difficulty in further tightening or untightening. Difficulties have been reported, particularly on untightening, with several CRAs, including titanium, Alloy 625 and 25Cr duplex stainless steels. Anti-galling treatments for these materials should be considered, especially where a requirement to untighten could be expected.

High strength cupro-nickel exhibits good resistance to galling. Bolts, studs and nuts can be specified in the same material with no requirement for anti-galling treatments.

9.3 Circlips, Hub Connector Clamps and Other Connectors

9.3.1 Circlips

Failures of precipitation hardened, martensitic stainless steel circlips on subsea equipment have been reported, e.g. in 15-5PH and 17-4PH type alloys. This has been found to be due to HE caused by high material hardness (46 HRC in one case) and CP. It is recommended that these alloys are not used for circlips if exposed to CP, and that the hardness of other materials be below the relevant

maximum specified by ISO 15156/NACE MR0175, or that established by experiment or operational experience.

9.3.2 Hub Connector Clamps

Hub connector clamps are normally manufactured in carbon steel, even where clamping CRA hubs, which is acceptable practice, provided adequate CP can be applied. Thermally sprayed aluminium coating of the clamp provides some increased level of protection where the CP may not be fully effective. Weld overlay with CRA, usually Alloy 625, of the internal surface of the clamp has also been specified in some cases. As indicated in the previous section, the bolting for these clamps is in low alloy steel, ASTM A 193 Gr. B7 or A 320 L7 (with controlled hardness).

9.3.3 Collet Connector Systems

Various proprietary collet connector systems are available for making subsea connections, for example between flowlines and manifolds or other parts of the subsea production system. These are mechanical jointing arrangements employing high strength steel components and gaskets. The same principles for materials selection as described above are applicable. Low alloy steel components exposed to seawater require hardness control to 34 HRC. Gaskets are typically Alloy 625, as described in the next section.

9.4 RTJ Gaskets and Other Metallic Sealing Rings

9.4.1 RTJ Gaskets

Material for gaskets in ASME RTJ type flanges are normally selected to be of lower hardness than the flange material to assist seating and prevent permanent damage to the flange ring joint.

Soft iron, with hardness less than 100 HB, has often been specified for carbon steel flanges. Although of low corrosion resistance, this material has been found to be suitable for subsea connections provided only corrosion from external sources is expected and that this can be adequately prevented by CP.

In many cases, however, CRA gasket materials are required, particularly where internal corrosion from the transported fluids is expected. Typically, Type 316 SS or Alloy 825 is specified, with a hardness limit of about 180–200 HB. Where these materials are specified, corrosion resistant inlay of the ring groove is also often required, normally Alloy 625 weld overlay. (*Note: ISO 13628-1 requires that all subsea flange connections be made with CRA gaskets and inlaid ring grooves*).

Alloy 825 gaskets are most commonly specified for CRA flanges. This material is not, however, fully corrosion resistant to sea water and may suffer preferential internal corrosion if the system contains untreated seawater for any length of time, e.g. after making subsea connections. This is a particular problem where the piping material is of higher corrosion resistance than the gasket (e.g. 25% Cr superduplex stainless steel). There is some evidence that microbial activity can accelerate this corrosion. Alloys with greater corrosion resistance have been used for gaskets, including Alloy 625 (fully annealed), Alloy 28 and S31254. Injection of oxygen scavengers and biocides has also been used during the make-up of

subsea connections of conventional and proprietary designs to alleviate the corrosion risks associated with raw seawater contamination.

Metal-to-metal seals that may be exposed to seawater without CP should be made in CRAs such as UNS R30035, R30003, Alloy 625 and Alloy C276. Generally, metal-to-metal sealing materials should be nobler than the surrounding surfaces.

9.4.2 Other Metallic Sealing Rings

The sealing rings for hub connectors and compact flanges are often specified in a material of higher strength than that of the flanges. For carbon steel hub connectors, low alloy steel, typically AISI 4130/4140, is used, normally conforming to the sour service hardness limitation of 22 HRC.

For CRA connectors, higher strength CRAs, typically 17-4 PH or 25% Cr superduplex stainless steel, are used for the sealing rings. Again, the sour service hardness limitation for these materials is recommended. The corrosion resistance of 17-4 PH is not high, and seal rings in this material can suffer from preferential internal corrosion from untreated sea water, as discussed for Alloy 825 above.

9.5 Non-Metallic Seals

Raised face type flanges, and hence non-metallic gaskets, are not used for main subsea flowline connections. Such flanges are also rarely used for subsidiary connections (chemical, hydraulic lines, etc.), but may be encountered.

External elastomer seals are used where relative movement between the flowline and seal is required (e.g. seals at the bottom of riser caissons).

In both of the above cases, the possibility of crevice corrosion at the metal-non-metallic seal interface needs to be considered, particularly for (otherwise) corrosion resistant alloys.

9.6 Bolt Tensioning / Controlled Torquing

Bolts for flanged and hub connections should be hydraulically tensioned or controlled torque tightened.

10. Flexible Pipe

10.1 Introduction

Flexible pipe can be unbonded, as per ISO 13628-2, or bonded, as per ISO 13628-10. ISO 13628-11 describes best practice in the application of both these technologies, and describes their use in both riser and jumper applications. These standards describe the *minimum* requirements for the design, material selection, manufacture, testing, marking and packaging of flexible pipes. Simple conformance to these standards may therefore be insufficient for any particular application.

Unbonded flexible pipes essentially consist of an extruded thermoplastic pipe, externally reinforced by a number of layers of high-strength steel wires, within an outer thermoplastic sheath. These structures find wide use in the full range of production and injection applications and this Chapter concentrates on this type of flexible pipe.

Bonded flexible pipes are generally steel wire reinforced rubber pipe structures, often referred to as hoses, which find limited application as static jumpers and risers on water and crude applications. Length is limited by the manufacturing method. Wider application of bonded structures is limited by the effects of gas decompression damage in thick rubber structures, and by limited knowledge of fatigue capabilities. Many of the materials considerations described in this Chapter regarding unbonded structures also apply to bonded structures.

10.2 Flexible Pipe Construction

The structure of a typical unbonded flexible pipe for subsea duty is shown in Figure 19. The innermost layer comprises an anti-collapse carcass manufactured from metal strip (typically 304L / 316L stainless steel or duplex stainless steel), rolled to form an interlocking spiral carcass. Extruded over this carcass is a thermoplastic sheath for fluid and pressure containment. Wound over the pressure sheath is a profiled, interlocking spiral strip to resist hoop stresses due to internal pressure.

An additional rectangular-section wire hoop stress layer may be added to reinforce the hoop stress armour, if required. Axial loads (tension and internal pressure) are taken by two or four contra-wound helical layers of tensile armour wires, separated in dynamic applications by plastic anti-wear tapes (these anti-wear tapes may also be used for stock pipe). All wires are manufactured from high strength carbon steel. A reinforced adhesive tape layer is wound over the outermost armour layer, and a thermoplastic external sheath extruded over the whole assembly, to provide abrasion protection and to avoid contact between the high strength steel wires and seawater.

10.3 Materials Issues for Flexible Pipes

10.3.1 Annulus environment

The annulus between the inner and outer thermoplastic sheaths contains the layers of steel reinforcement wires that give the flexible pipe its tensile and hoop (pressure retaining) strength. This annulus would normally be expected to remain dry during service. However, the polymers used for the inner pressure

sheath are permeable to gas, including any corrosive gases (H_2S , CO_2) in the transported fluids, and also to water. The diffused species can therefore initially produce a low pH aqueous environment in the annulus, though studies have shown that corrosion is limited due to the confinement effect and the limited amount of diffused water, resulting in an increase in pH. For sour service conditions there is potential for H_2S -related problems (HIC, SSC) for the reinforcement wires unless qualified grades are specified.

Corrosion-fatigue of reinforcement wires may limit the life of dynamic risers. If the flexible pipe suffers external mechanical damage such that seawater flooding of the annulus occurs, then annulus conditions are likely to become significantly more corrosive (see Figure 20). Although CP can protect the wires local to the damaged area, the service life will be limited by the requirement to assume corrosion fatigue in wet conditions instead of dry.

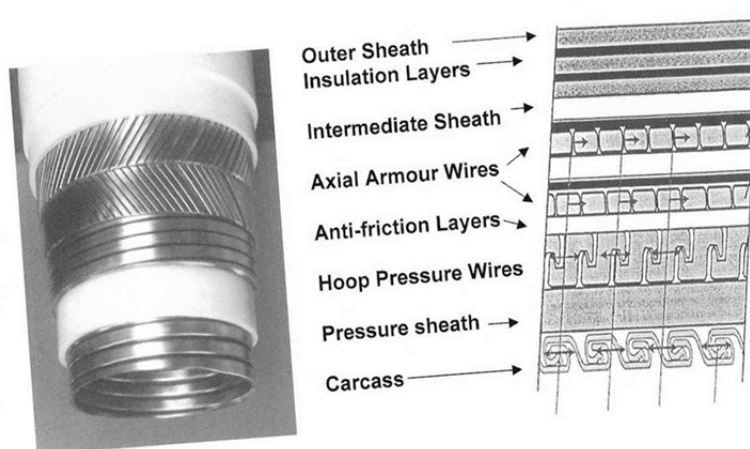


Figure 19 Typical construction of unbonded flexible piping for subsea application



Figure 20 Damaged flexible riser with reinforcing wires exposed

10.3.2 Tensile Armour Wires

Tensile armour wires provide the flexible pipe with its tensile/bending strength. They are normally plain 'rectangular section' wires (with the edges 'rounded off' to prevent sharp edges). There are normally two or four layers of wires each containing many strands of wire, e.g. 50–60 wires/layer for a typical 10 inch ID pipe. Alternate layers are counter-wound to torsionally balance the pipe.

The steel wires are high strength to achieve the necessary pipe properties. This strength is achieved by either cold working or heat treatment, which means that the wires are not normally 'fully sour resistant', i.e. they can suffer from SSC and/or HIC if the conditions are conducive. Annulus conditions can be predicted by existing permeation models, and it is recommended that checks be made to ensure that the wire material selected for any application has adequate sour resistance for the intended duty. A number of manufacturers of flexible pipe have developed high strength steel wire materials with improved sour resistance, but full sour resistance still cannot normally be guaranteed.

10.3.3 Pressure Armour Wires

Pressure armour wires (hoop strain) provide the pressure-containing capacity. Normally they comprise a single layer against the inner polymer pressure sheath, often constructed from just two continuous wires. The two wires interlock with each other to prevent separation during service. There are a number of interlocking techniques. Sometimes a second hoop layer is added to deal with very high operating pressures.

Shaped pressure armour wires are manufactured from the same high strength steels used for the tensile armour wires, and the same materials considerations apply. As a result of the additional metal forming (which is often a cold process) there can be a decrease in the sour resistance to both SSC and HIC. The effects of HIC on the wire integrity can be significant because longitudinal cracks can result in the wires 'splitting', eventually causing a loss of pressure containment. As a result of the sensitivity of welds to SSC, wire welds should be staggered and not located in critical dynamic areas of the riser, e.g. close to the bend stiffener.

Pipe manufacturers should undertake a 100% inspection of the supplied wire prior to pipe fabrication. Normally, mill defects are marked by paint and cut out by the pipe manufacturer if the defect exceeds their acceptance criterion. Wire defects should be investigated to ascertain the cause, with the objective of eliminating the source, e.g. poor handling or storage.

10.3.4 Fatigue Life Considerations of Reinforcement Wires

In the case of dynamic risers, the steel reinforcement wires are subjected to fatigue loading in service, which is normally at its worst at the top of the riser, in the bend stiffener region. The fatigue life of the risers will then be governed by the riser performance in this region.

Fatigue life prediction tools are typically based on the use of S–N curves derived from small-scale (single wire) fatigue tests. Fatigue curves may be statistically analysed to provide a given 'probability of failure'. Fatigue stresses, calculated from 'metocean' (meteorological and oceanographic) data, are then combined with these curves in a Miner's Rule approach to determine fatigue life. For fatigue

life assessments using air fatigue curves, the design of the flexible riser is often such that the stresses in the reinforcement wires will remain below the air fatigue limit, i.e. in theory the wires will have an infinite fatigue life. Even with undamaged risers there is a risk of 'water wetting' of the wires with a corrosive environment due to permeation. In this case, 'corrosion-fatigue' rather than pure fatigue should be considered. For externally damaged risers, it is possible that the annulus will be flooded with seawater, and again corrosion-fatigue rather than pure fatigue should be considered. It is well known that for corrosion-fatigue there is no fatigue limit, i.e. the pipe structure will have a finite life.

For undamaged risers, the main issue is one of deciding for what periods over the riser life the reinforcement wires will be water wetted, and the effects of this on the fatigue and hence service life. Designs will typically assume the wires are never water wetted (using air fatigue S-N data) or that they are water wetted all the time (using the relevant corrosion-fatigue S-N data). Manufacturers have tools to assess water diffusion from the internal bore through the pressure sheath and can predict how long it will take for the annulus to flood. Fatigue calculations can be done for both dry and water wetted periods and in conjunction with annulus testing to establish whether it is dry or wet, a combined 'dry' then 'wet' assessment can be performed.

For damaged risers, the issue is one of determining the residual life 'post-damage', as seawater ingress into the annular space between the inner and outer plastic sheaths can result in a significant reduction in fatigue life. To mitigate the effects of annulus seawater ingress, corrosion inhibitor displacement treatments, including outer sheath repair technology, and associated corrosion-fatigue models have been developed and used within the industry. Seawater ingress no longer automatically demands riser replacement.

There is a need for further development of flexible riser corrosion-fatigue life prediction tools to enable the necessary assessments to be made for the full range of operating conditions including sour service where applicable. The corrosion-fatigue performance of the steel reinforcement wires in the corrosive environments likely to occur in the annulus requires further studies. Manufacturers and users have in-house programmes to develop such information for their particular products and conditions. In addition there are some cross-industry initiatives managed by bodies such as MARINTEK (Norwegian Marine Technology Research Institute) and MCS (Marine Computation Services). In the meantime, it should be realised that flexible pipe design and operations need to take due account of these uncertainties.

10.3.5 Internal Metal Carcass

Flexible pipes frequently have an inner metallic carcass manufactured from thin metallic strip (sometimes multi-layered) fabricated into an interlocked (roll formed) or corrugated tube. The carcass's main function is to provide external collapse resistance, e.g. in the event of a vacuum occurring in the pipe or if the outer sheath is breached. This is particularly important for deep water applications.

The material selected for the carcass clearly needs to have sufficient corrosion resistance to the fluids likely to be present in the flexible pipe (e.g. high chloride-containing fluids). It should also address fluids present for short periods. For example, it might be necessary to acidise a well via a flexible pipe, in which case

the carcass material needs to have adequate corrosion and SCC resistance to the acids being transported. The corrosion control treatment component of the acidising package would also need to take due account of the requirements of the internal metal carcass material. Alternatively, the flexible pipe may need to carry oxygen-containing seawater for short periods. If this is the case, the chloride SCC resistance of the internal metal carcass needs to be considered.

Sufficient erosion resistance is also required, especially if fluids containing solids (sand) are to be transported. This may affect both the materials selection and the thickness of the metal sheet used, and should be assessed using either publically available erosion guidance such as DNV RP0501, or in-house erosion models which tend to be less conservative. Full scale testing to enable calibration or verification of these models is understood to be very limited.

The carcass material should have adequate mechanical strength for collapse resistance. This will also need to take account of the effects of wastage resulting from erosion, especially as the carcass is thin and needs to retain a certain minimum thickness to maintain its collapse resistance.

For gas duties, the potential for carcass induced vibration and noise should be assessed, as it can be transmitted to connected pipework and equipment causing acoustic fatigue.

Typical materials used for the inner carcass include AISI 304L, 316L and duplex stainless steels. In many instances, it may be necessary to undertake corrosion/SCC tests to pre-qualify the material for the intended duty.

10.3.6 Thermoplastic Inner Sheath

The inner thermoplastic sheath provides the main pressure barrier for the flexible pipe, structurally supported by the steel pressure armour. For production and gas injection, polyamide 11 nylon can be used at low to moderate temperatures, and polyvinylidene fluoride (PVDF) at elevated temperatures. For water injection service, the normal material employed is PE.

Polyamide PA-11 nylon is the standard option for production/hydrocarbon service. The upper service temperature is limited by the degradation of the polymer under 'wet' acidic conditions, i.e. serviceable to 90°C in 'dry' service, 70°C in 'wet' service. Alcohols, particularly methanol, also affect the material. Detailed analysis is required to predict actual service life. Further guidance is available in API TR 17TR2 (2003). This Technical Report is generally accepted to be conservative. The evaluation Standard for internal pressure sheath polymers is API TR 17TR1.

PVDF is a high temperature option for production/hydrocarbon service. It is chemically inert, but has mechanical limitations, e.g. notch sensitivity. Crack growth models as a function of severity of thermal transients during operation or shutdown are available. Original PVDF grades had high levels of plasticisers, which led to shrinkage and end fitting problems. Newer grades avoid this problem. PVDF is qualified to a maximum of 130°C and is normally limited to -20°C. In dynamic pipe structures, PVDF is often extruded in two or three layers, to protect the main pressure sheath during extrusion and during service. This has led to problems in high pressure gas service, and the potential for the

collapse of multi-layer sheathes in such service should be addressed at the design stage.

PE is the primary materials selection for water injection service up to around 65°C. PE may also be specified for hydrocarbon service, although precise limitations in terms of temperature and pressure are not agreed across the industry. Cross-linked polyethylene (XLPE or PEX) is a high temperature version of PE, probably serviceable in water duty up to around 90°C. Once again, hydrocarbon resistance is not well defined, but recent data suggests only a 10°C improvement over HDPE. Limited resistance to low molecular weight aromatic hydrocarbons and blistering in gas service are particular issues with PE and PEX materials. An advantage of PE over PVDF is a potentially lower temperature limit which can typically be used down to -50°C, although some manufacturers are currently qualifying PVDF flexibles for -30°C.

For applications at temperatures above the limit permitted for PVDF, it may become necessary to either use alternative materials or thermal barrier layers. Developments in these areas are ongoing primarily with the use of a thermal barrier.

All internal polymer sheaths allow fluids to permeate into the annulus, the speed of permeation being a function of the material, fluids, pressure and temperature. Current permeation models predict permeated volumes with reasonable accuracy. Prediction of the composition of annulus gas is less accurate, but still useful in assessing the effect of annulus conditions on reinforcing wires.

The condition of the pressure sheath forms an important part of overall pipe integrity management. With PA-11 sheaths, for example, polymer life analysis is typically based on in-service coupon analysis, by molecular weight determination interpreted as a function of cumulative process data, i.e. time-temperature-environment history. For PVDF, relating thermal transients to the potential for crack growth within the sheath is important.

At the design stage, the collapse resistance of the pressure sheath (combined with the internal carcass, where present) should be assessed under all operating conditions.

10.3.7 Anti-Wear Tapes

In dynamic applications, anti-wear tapes are used to prevent metal-to-metal contact between adjacent axial armour wires. Several different polymeric materials are employed, including polyolefin materials such as PE and polypropylene, and polyamides. At high temperature (> 100°C), fluoropolymer based formulations are available. Each manufacturer confirms the performance of their specific anti-wear tape materials by a combination of laboratory scale tests and full-scale dynamic riser tests. A review of anti-wear tape capability should form part of the design review of any dynamic pipe application. At elevated temperature, anti-wear tape degradation mechanisms, such as chemical ageing, need to be taken into account.

10.3.8 Thermoplastic Outer Sheath

Static pipe usually has a PE outer sheath, while PA-11 is used on dynamic pipe. The major issue is damage of the sheath during handling and installation, leading

to a seawater flooded annulus, and corrosion-fatigue/corrosion. It is important to externally protect potentially vulnerable areas and ensure that the installation procedures are adequate and are followed. One option used for risers in FPSO turrets is to apply a double layered PA-11 sheath.

10.3.9 Composite Reinforcement Wires

Some manufacturers have produced flexibles using lightweight carbon fibre reinforced polymeric tensile armour tapes. These pipe designs are primarily being developed for deep water applications (circa 2500 m) where weight saving and reduced OD may provide a cost-effective, viable solution. They would also be potentially attractive for high pressure sour service applications.

10.3.10 Thermal Insulation

Thermal insulation can also be applied in flexibles, although PVDF provides some insulation itself. The main issue with thermal insulation is its ability to maintain sufficient insulating properties under realistic combinations of temperature and hydrostatic pressure, and with the potential ingress of seawater. Manufacturers are able to calculate the U-values of their designs under dry or wet conditions.

Thermal performance of flexible pipe structures is complex, being influenced by water depth, pipe diameter and layer materials. Typically, pipes without insulation will have U-values in the range 10 to 20 W/m²K, depending on bore surface area. This is reduced to ca. 5 W/m²K with 40 mm of insulation, and to ca. 2 W/m²K with 80 mm.

10.3.11 Fibre Optics

At least one manufacturer has developed fibreoptical sensors which can be used to monitor strain and annulus conditions (pressure, temperature, gases). For strain measurement the fibreoptic wires are embedded in the inner tensile armouring layer and allow direct measurement in the most fatigue-critical layer at the points of highest loading. Use of fibreoptic sensors allows condition monitoring of the flexible pipe and also detection of significant events such as a breach of the outer sheath. Gathering of such data will also facilitate lifetime extension assessments.

10.4 End Fittings

End fittings for flexible pipe are proprietary designs for which there are no published detailed drawings. However, in all cases, a seal is achieved by mechanical compression and constraint of the pressure sheath.

There have been well-publicised problems with end fittings on pipe using PVDF pressure sheaths. There have been no reported field problems with either PA-11 or PE end fittings.

The main failure mode relates to the movement of highly plasticised PVDF in the end fitting sealing system due to thermal stresses and massive shrinkage during leaching of the plasticiser. In some field cases the sheath moved completely out of the end fitting, resulting in loss of pressure integrity. Improved materials, design and mounting procedures have now largely eliminated this mode of failure. End fittings for pipe using highly plasticised PVDF in gas service require

pre-deplasticisation of the pressure sheath where the end fitting is to be mounted. This process can take several weeks, and is a major reason for suppliers introducing low or zero plasticiser versions of PVDF.

A secondary failure mode, seen only in laboratory testing, relates to potential fracture initiation at machining marks, on the OD of the PVDF pressure sheath, introduced as part of the end fitting mounting process. Care needs to be taken in machining the pressure sheath, and an automated process is preferred. Analysis of the effects of machining marks is required in every application.

End fittings, particularly with PVDF sheaths, should be qualified by exposure to elevated temperature and thermal transients, in accordance with ISO 13628-11 Annexes A and C. Additional project-specific testing may be required. End fittings are not generally rated to the same lower temperature limit as the pressure sheath polymer alone. For example, end-fitting thermal cycling typically goes down to 0°C or –5°C, while a PVDF material itself may be qualified to –20°C.

End fitting seals to the external sheath also need consideration. Field experience suggests some evidence of leakage in past applications.

End fittings are normally fabricated from carbon steel, low-alloy steel or duplex stainless steel. For corrosive duties or where solids (sand) production is expected, a CRA or Alloy 625 weld-overlaid carbon or low alloy steel is recommended.

10.5 Bend Stiffeners

Most dynamic riser bend stiffeners consist of large moulded polyurethane conical elements into which metallic support frames and surfaces are incorporated.

There have been a number of instances of failure during test, and at least one field failure, all characterised by catastrophic failure through the rubber and separation of the stiffener into two parts. These have generally been related to insufficient metal insert-to-polymer bonding at critical parts of the stiffener. Manufacturing QA/QC needs to pay attention to obtaining optimum bonding, as this cannot be inspected post-moulding.

Recent applications have required extremely large stiffeners to be manufactured. In such cases, attention needs to be paid to mould fill time relative to polymer gel time, and to inspection and repair of any defects in the moulding.

10.6 Flexible Pipe Integrity Management

Any operator of flexible pipe needs to develop a systematic integrity management programme, and many aspects of this will be materials-related.

'State of the Art Report on Flexible Pipe Integrity and Guidance Note on Monitoring Methods and Integrity Assurance for Unbonded Flexible Pipes (2010)' is available from Oil & Gas UK. This summarises current industry practices in the North Sea area on flexible riser integrity management.

11. Hydraulic Control and Chemical Injection Systems

11.1 Introduction

Subsea control systems allow the operation of valves and chokes on well completions, trees, manifolds and flowlines. They usually use hydraulic power, delivered from the surface via an umbilical. Most subsea developments also require injection of chemicals, e.g. for controlling internal wax formation, scaling, hydrates and corrosion.

11.2 Materials Selection

11.2.1 Hydraulic Control System Fluids

Subsea hydraulic control fluids are either water/glycol-based or oil-based. Recommendations for fluid properties and for qualification testing are described in ISO 13628-6 Annex C. Water/glycol fluids usually comprise a mix of additives (corrosion inhibitor, bactericide, fungicide, lubricant, etc.) in aqueous solution, plus ethylene glycol when required for antifreeze or for control of fluid viscosity. Typical formulations for the North Sea might contain up to 40% glycol at a pH of around 9.

The qualification tests in ISO 13628-6 Annex C for water/glycol-based fluids include thermal stability, compatibility with seawater and various operational fluids, metal and elastomer / thermoplastic compatibility, filterability, lubricity and wear. The metal compatibility test assesses the corrosivity of the fluid as well as the tendency for it to degrade and/or form deposits on the metals, at three temperatures: 20°C, 60°C and at the maximum operating temperature plus 10°C. The fluids are tested neat and with 10% by volume seawater contamination. Prolonged exposures are required, followed by detailed examination of the fluids and the metal samples. The test metals specified are:

- Carbon steel.
- Aluminium bronze.
- Tungsten carbide with 10% nickel binder.
- Beryllium copper.
- Type 316 stainless steel, to include crevice.
- 17-4 PH, to include crevice.
- Carbon steel - 316 SS galvanic couple.

ISO 13628-6 Annex C specifies corrosion testing of oil-based fluids to ASTM D665 using carbon steel test pins.

316L stainless steel to ASTM A 269 is a common choice for the small diameter control tubing and components, especially for shallow water installations. These items are not usually painted, and the control lines will be cold bent, but external corrosion and chloride SCC will be prevented as long as all the components are electrically continuous with the associated structure, and thereby tied into the CP system. Intergranular corrosion testing, which is a supplementary requirement in ASTM A 269 is recommended.

For high pressure / deep water installations and for elevated design temperatures, higher alloy austenitic CRAs are recommended for hydraulic tubing. Suitable options include Alloy 825 to ASTM B 423, 6% Mo superaustenitic

stainless steel to ASTM A 269, and Alloy 625 to ASTM B 444. In each case, corrosion testing and / or microstructural examinations are recommended to assure the correct supply condition.

Although duplex and superduplex stainless steels, e.g. to ASTM A 789, are candidate alloys for hydraulic control tubing, there is the potential risk of external hydrogen embrittlement, given that the tubing will be locally cold worked, will not be externally coated and will be subject to hydrogen charging from the CP. Autogenous welding will require particular care to avoid high ferrite welds that would increase the risk of hydrogen embrittlement.

The main corrosion concern for control systems arises from excessive seawater contamination of the hydraulic fluid. Control system failures in at least two subsea fields have been attributed to this problem. Minor contamination is almost inevitable during the make-up of the subsea umbilical and jumper connections, and the control fluid additives are formulated to deal with this; but any major contamination is likely to result in internal fouling and corrosion from the proliferation of bacteria and fungi. Fouling may be caused by the build-up of dead organisms, corrosion product or, in the case of extreme levels of sea water contamination, by the break out of the lubricant package (i.e. precipitation of lubricant components). The action of micro-organisms results in a decrease in control fluid pH and localised corrosion. Control system components in martensitic and precipitation hardened grades of stainless steel such as Type 440 and 17-4PH, which have relatively low pitting resistance, are particularly at risk. Electroless nickel-plated steel components are also likely to suffer corrosion, especially if the system is not quickly commissioned. The types of small components that can be affected include directional control valves and solenoid-operated pilot valves in the control pods.

Good practice to minimise the risk of this problem is to:

- Ensure any water used for solution make-up is not contaminated (though most solutions are now premixed).
- Ensure all system components are clean and free from contamination prior to assembly.
- Biologically clean and flush the system immediately prior to charging with control fluid, ensuring all air is expelled. Failure to remove all entrapped air will permit greater levels of seawater contamination to occur during deployment.
- Consider use of fluid-filled pressure compensators, designed to keep the pressure in the control system above the ambient pressure during deployment. These can be temporary devices to be subsequently removed by divers or ROV.

Zinc- and cadmium-plated carbon steel components are not recommended for control systems due to the risk of corrosion and fouling. Aluminium should also be avoided. Painting of internal hydraulic surfaces (e.g. reservoirs) is not recommended, since any paint failure could lead to system contamination.

Compatibility of non-metallic components such as seals with neat aqueous control fluids is not usually a problem, but potential contact with other fluids e.g. cleaning fluids, greases, dielectric fluids, production chemicals, completion fluids and seawater, can present some compatibility challenges, requiring more chemically resistant grades.

11.2.2 Chemical Injection Systems

The subsea chemical injection system distributes chemicals from the umbilical termination head to each well or manifold header. Depending on the chemical, the flow capacity of the distribution system may be substantially greater than that of the hydraulic control distribution system. Additionally, the pressure rating of the components is typically higher, compatible with the wellhead system rating, and the corrosivity of the fluids conveyed is typically more severe.

Materials selection for chemical injection duties is mainly driven by the corrosivity of the chemical, either in its intended concentration and purity, or when contaminated by seawater. Also, contamination of injection chemicals and increased temperatures caused by backflow of produced fluids may need to be considered for part of the system, e.g. up to check valves. Hence, in addition to 316L SS, there may be applications for more corrosion resistant austenitic alloys in these systems such as super-austenitics, and Alloys 400, 825 and 625.

The selection of non-metallic seal materials for chemical injection duties is usually more critical than for control fluids. The usual option is either to select for the individual chemicals if they can be specified at the project design stage, or to select a material with good all-round chemical resistance such as FFPM perfluoroelastomers (e.g. Chemraz, Kalrez) or PTFE. Seals for high pressure should be designed accordingly, e.g. hard O-rings, plastic anti-extrusion rings.

There have been frequent reports of methanol leaks in connector systems. Methanol has the ability to pass very tiny openings, and as soon as a small leakage starts, it rapidly develops due to cavitation. Metal-to-metal sealing for methanol service is therefore a key point for design, qualification and testing. For metal-to-metal seals there is also a requirement for a non-metallic back-up seal. The well-known limitations of titanium in methanol duty should be taken into account: at least one incident of a failure of a methanol injection system due to SCC of a titanium seal ring has been reported.

11.3 Tubing Connections

11.3.1 Introduction

For most onshore and offshore topside applications, both screwed and compression fittings are used to fabricate small diameter tubing systems. While these joining techniques generally perform adequately under normal atmospheric conditions, they do not present a sufficiently low risk of leakage for subsea application. Make-up problems with each of these techniques can lead to incipient leak paths that are difficult to detect prior to installation and service.

In subsea applications, the leakage of hydraulic control fluids and treatment chemicals will often be unacceptable both from the environmental and the operational points of view. Consequently, a high reliability joining technique is required for the small diameter hydraulic/chemical injection tubing and associated fittings.

11.3.2 Permanent Connections

The recommended joining technique for permanent tubing connections in subsea applications is welding, employing the gas tungsten arc (GTAW) process.

Although manual welding techniques may be employed, it is recommended that automated orbital welding be utilised in order to ensure the consistent and cost effective production of high quality defect-free welds, especially for the smaller tubing diameters. Automated welding may be used for both tubular butt joints and socket weld fittings. Butt joints are usually preferred to socket welds since they do not contain an internal crevice and are more suited to volumetric non-destructive examination. In the size range of present interest, typically ¼ to 1 inch OD, the process is usually employed autogenously (i.e. without addition of filler material) with specially manufactured 'automated welding' fittings. These fittings often contain additional material for filler purposes machined as an integral part of the fitting body. However, the process can be employed with filler additions for the larger tubing sizes if necessary. Tube ends need to be prepared by machining in order to facilitate the consistent, tight fit-up tolerances required by the process. Simple portable power tools are available for this operation, and the fittings usually incorporate a captive end preparation to assist fit-up. Careful capture and removal of all swarf is important to maintain system cleanliness.

Once an acceptable welding condition has been established and entered into the equipment memory, automated orbital welding is capable of producing large numbers of high quality welds without further adjustment, provided the necessary level of fit-up tolerance is maintained.

The use of automatic orbital welding equipment does not guarantee freedom from weld defects, and where random radiographic checking has been performed significant weld defects have been found: in one case excess penetration had completely blocked the tube. Hydraulic tube failures have resulted in well shut-in and lost production resulting in significant costs and delay to rectify the situation. For critical controls tubing where failure could result in significant costs, e.g. tree shut in, the use of radiographic examination is recommended.

Autogenous welding processes on duplex or superduplex stainless steels require careful qualification due to the possibility of obtaining excessive ferrite content in the weld, resulting in a high susceptibility to hydrogen embrittlement from the CP.

Additional guidance is offered in Appendix VI.

11.3.3 Demountable Connections

When it is absolutely necessary to use a demountable fitting to facilitate assembly or maintenance, a high integrity tube fitting utilising a straight thread and incorporating an O-ring face seal should be considered. For high pressure demountable connections, when the design pressure is greater than the maximum working pressure for O-ring face seal fittings, proprietary coned and threaded fittings may also be considered.

Demountable connectors in 316 stainless steel are commonly specified, and appear to have a good track record. However, seawater penetration to the 'internals' is inevitable in most existing designs, raising the question about long term integrity due to crevice corrosion, the internals possibly being shielded from the CP. Consideration should therefore be given to the use of more highly alloyed CRAs for these connectors.

Conventional compression fittings as used for surface facilities are not

recommended for long-term use subsea due to the problems of make-up quality control and the difficulty in detecting incipient leaks. Such leaks are likely to gradually worsen in service. Ferrules made from hardenable grades of stainless steel such as 17-4PH may suffer crevice corrosion and should be avoided.

Brazed or silver soldered fittings are not recommended due to inadequate corrosion resistance.

NPT-type connections are also not suitable for long-term subsea service due to inadequate leak integrity.

PTFE thread tape should not be used since this could mask poor assembly technique, and affect electrical continuity.

11.4 Hydraulic and Chemical Injection Valves

Needle/globe valves, gate valves and check valves are available from numerous suppliers and vary significantly in their design and construction. Most of them are manufactured from 316L or duplex/superduplex stainless steels, with varying amount of attention being given to materials selection for the internals to avoid galling of the moving parts. Provision of seals also varies as to number and quality. Another detail often overlooked relates to the lack of differential hardness between the needle valve stem points and the seats. Materials selection for valve bodies would normally follow that for the associated tubing, 316L being the standard for hydraulic fluid valves, and other CRAs possibly being required for chemical injection valves dependent on the corrosivity of the chemical and the likelihood of contact with the production fluids.

Corrosion of internal high strength/hardness hydraulic valve components made from martensitic or precipitation hardened grades of stainless steel such as type 440 and 17-4PH may occur in the event of seawater contamination. These grades have relatively low resistance to pitting and crevice attack, and upgrading to more corrosion resistant CRAs should be considered.

Problems were encountered in one design of check valve when the elastomeric O-rings fitted into a groove on the conical surface of the poppets became detached during system flushing. If such elastomers are specified for sealing, then their strength and hardness should be adequate to avoid displacement. Metal-to-metal seal designs are generally preferred to avoid the problem altogether.

Other problems have been encountered with relief-check valves in control pods, which relieve control fluid pressure to the sea, when the build up of calcareous deposits has caused their seizure. Lengths of plastic tubing have been fitted to the discharge port of the valves in an attempt to insulate the valves from CP.

Valves should be specified with butt-welding end connections.

11.5 Hydraulic and Chemical Injection Couplers

Couplers are proprietary items, used for the subsea make-and-break connections between the umbilicals/jumpers and the hydraulic/chemical systems. When mated, a male part seals against a female part. When unmated, flow is prevented by a stainless steel sealing device: this is pushed aside when the final

mating of the connectors is achieved. This type of self-sealing minimises ingress of sea water during coupling, but could still allow sea water entry if the pressure rating of the spring-loaded poppet is exceeded by the hydrostatic pressure. The primary metal-to-metal seals in these devices are typically gold plated Alloy X-750, with a thermoplastic or elastomeric back up.

Where several couplers are mounted together on a stab-plate to facilitate the subsea coupling process, it is usually necessary to allow some movement of the individual couplers so that each male part can centre exactly into its corresponding female part. In at least one design, this entails the use of circlips located in a groove around the female coupler body on the reverse side of the mounting plate. Such circlips, made from precipitation-hardened stainless steel, have been known to fracture by hydrogen embrittlement due to excessive hardness, thereby preventing uncoupling.

Problems with couplers have been reported when seawater ingress into a methanol system resulted in the deposition of salts (gypsum), preventing sealing during make-up. The build up of calcareous deposits on couplers has also led to problems in subsequent make-up, and has been addressed by the application of greases to provide temporary insulation from CP.

As noted in Section 3.6, certain low PREN grades of austenitic stainless steels such as UNS S 21800, which have been formulated primarily for wear and galling resistance, are sometimes offered in the cold worked condition for hydraulic couplers. These alloys may even have received a heat treatment that results in sensitisation. Failures by pitting and stress corrosion cracking have been reported on hydraulic couplers manufactured in these types of alloys due to exposure to marine environments.

Precipitation-hardened copper–nickel alloys have potentially attractive properties for certain designs of connector, i.e. high strength, high corrosion and marine bio-fouling resistance, freedom from hydrogen embrittlement, and anti-galling behaviour. Successful uses to date include stab-plates for electrical and hydraulic connections. As with all precipitation-hardened alloys, welding is not normally recommended unless the local reduction in mechanical properties can be accepted. Published data indicates that welding can be successfully achieved on these alloys with only a modest loss of properties.

11.6 Tubing Design and Supports

All control and chemical injection tubing runs and associated fittings require to be adequately supported to prevent vibration in service and to avoid premature joint leakage or fatigue failures. Tubing design and layout should be documented and shown on drawings, rather than 'hand fitted' around other equipment; the design should also consider external loading, e.g. vortex induced vibration and marine life interaction on small diameter tubing. In one tubing failure it was shown that a 20 kg fish could result in loading exceeding yield stress and a tube deflection of 15 mm.

It is important that all these supports, clamps, etc. are electrically continuous with the tubing and with the supporting structure in order to avoid corrosion. Problems have arisen with 'stacked' clamp designs for the support of multiple tubing runs where electrical continuity had been lost, and rapid corrosion of the (incorrectly specified) free-machining securing bolts has led to failure.

12. Umbilicals

12.1 Introduction

Control and service umbilicals are used for the supply of service fluids or electrical and hydraulic power and signals between a topsides host (platform, FPSO, etc.) and a subsea template or manifold facility, between the host and an individual subsea wellhead, or between individual topside facilities with a subsea linkage (e.g. platform to FPSO).

Depending on service requirements, umbilicals may carry electrical services only, hydraulic or chemical fluids only, or a combination of these. In the simplest system, an umbilical can provide a single hydraulic fluid conduit and electrical power connection to a single wellhead. More usually, umbilicals carry a relatively large number of fluid conduits, power supplies and signal connections to a full subsea production system as follows:

- hydraulic power supply conduits to subsea equipment (high and low pressure);
- electrical power supply cables to subsea equipment;
- signal cables for subsea facilities;
- chemical conduits for subsea injection, e.g. corrosion, wax and scale inhibitors; and
- methanol transport conduits.

In addition, umbilicals may also include other items such as a bleed conduit for the well annulus fluids and optical fibres for high volume data communication. Figure 21 (overleaf) shows cross-sectional arrangements of typical umbilicals.

Umbilicals are key items of subsea production systems and may represent a significant cost component. They can be expensive both to fabricate and to install, but most importantly can result in total shutdown of a subsea facility if they fail. The reliable repair of defective or damaged umbilicals after installation (e.g. by splicing) is at best difficult to achieve and may be impossible with some designs. Hence there is a need to ensure that the complete umbilical system is designed, manufactured, tested, installed and commissioned to the best available practice and in accordance with international standards, in order to provide acceptable long-term service. It is important that this assurance includes the ability of the selected umbilical materials (both metallic and non-metallic) to withstand attack both externally from seawater and internally from the chemicals transported through the individual fluid conduits. It also needs to include resistance to the external hydrostatic pressure and to high ambient temperatures generated by production fluids in flowlines in close vicinity, (e.g. in an FPSO riser turret or in the same trench as a pipeline).

12.2 Umbilical Design

12.2.1 Types of Umbilical

Subsea control and service umbilicals are either dynamic, (e.g. for FPSOs), or static (e.g. for fixed platforms). The carrier conduits used for transporting the various fluids can either be of the flexible fibre-reinforced thermoplastic hose type or of the metal tube type.

Fluid conduits and electric or optical fibre cables in an umbilical with thermoplastic hoses are usually surrounded by a system of armour wires, which amongst other functions provides protection against external damage. Fluid conduits and electric or optical fibre cables in an umbilical with metallic tubes are often positioned with plastic spacers or profiles. The armouring layer or system of profiles is covered with an external thermoplastic protective sheath, e.g. PE, though this is not designed to exclude the seawater, and may even be perforated for ease of installation. Individual conduits and cables are completed at each end of an umbilical in an end termination, which connect the various services to the topside host and/or the subsea facility as applicable.

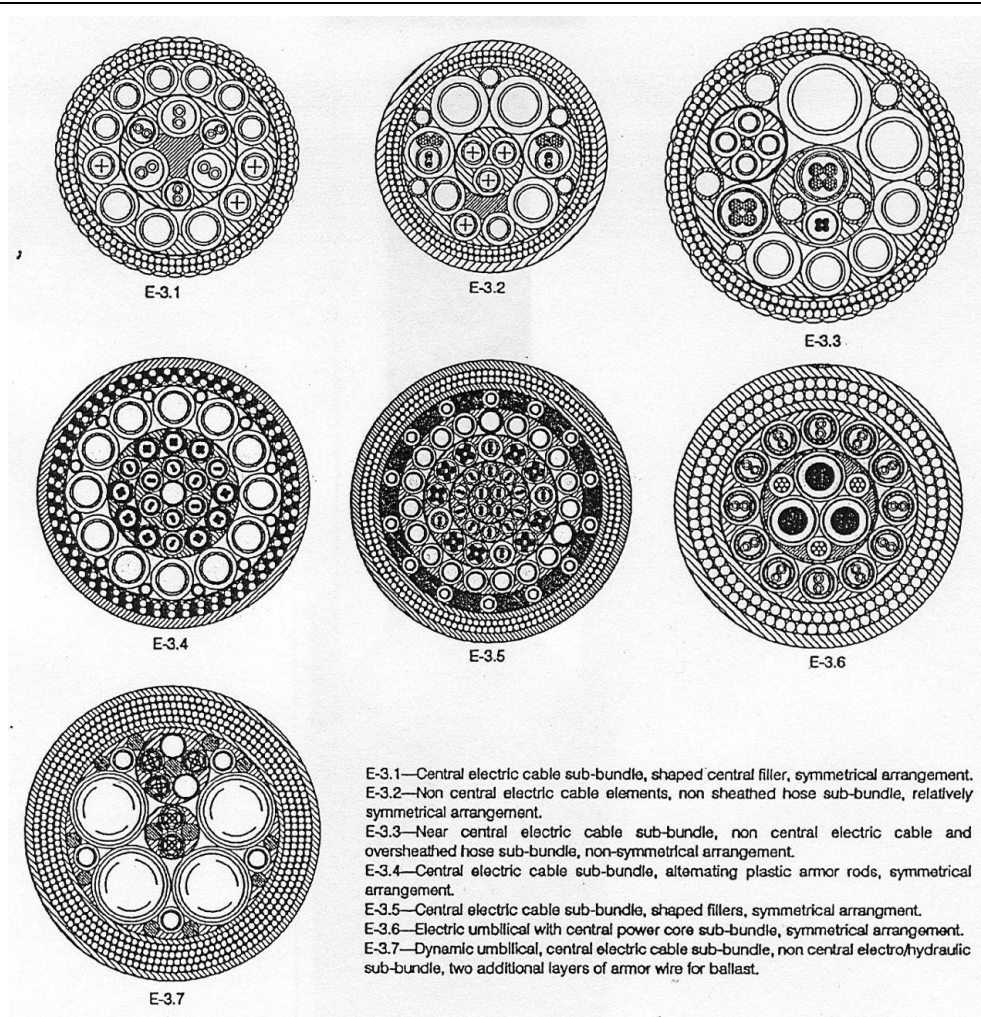


Figure 21 Typical umbilical cross-sectional arrangements

(Reproduced from API Specification 17E, *Subsea Production Control Umbilicals*, 2nd Edition, March 1988, courtesy of the American Petroleum Institute. Document superseded by 4th Edition, October 2010, identical to ISO 13628-5)

12.2.2 Umbilical Specifications

Requirements for the design, manufacture and installation of umbilicals is contained in ISO 13628-5, based on and identical to ANSI / API Specification 17E.

The ISO Standard defines generic materials testing and inspection requirements for both umbilical types, but for specific materials such as 25% Cr superduplex stainless steel, supplementary requirements may be necessary. For instance, for 25% Cr superduplex tubes it is recommended that a minimum PREN / PREw value of 42 should be specified for increased integrity.

CRA tubes are generally considered preferable to carbon steel and to non-metallic tubes because of their superior chemical resistance, improved internal cleanliness and greater operational flexibility (changes of duty).

The design of end terminations is outside the scope of ISO 13628-5 although guidance is given in the document. It is usually covered by codes such as ASME B31.3, ASME VIII or (BSI) PD 5500, with welding and fabrication to related codes, e.g. ASME IX, API 1104, BS 4515 and ISO 15614.

12.3 Materials Selection Considerations

12.3.1 Non-Metallic Hose Conduits

For umbilicals where the fluid carrier conduits are of the non-metallic hose type, the hoses are generally of three-part construction: an inner extruded thermoplastic liner (diaphragm seal) in contact with the pressurising or transported fluid, a synthetic fibre reinforcement layer to contain the operating pressure, and an outer thermoplastic sheath for protection.

The main choices for the inner liner, which are specified in the various referenced standards or offered by suppliers, are polyamide 11, cross-linked polyethylene or polyamide 12 with a thin fluoropolymer inner layer. Thermoplastic polyester, although once popular, is now seldom used. The reinforcement layers are usually aramid fibres. Outer sheaths may be polyamide 11 or polyether-based polyurethane.

Umbilicals containing a centrally located large bore flexible conduit are also available, and these may become attractive for deep water dynamic schemes, especially where the delivery of large volumes of chemicals is required. Such designs may have superior fatigue resistance compared with steel tubed constructions and may have lower weight, though this in turn will result in greater movements.

Non-metallic hose umbilicals generally have lower installation costs and are more flexible and easier to hang off. They are also easier to repair, but the temperature of the transported fluids is normally limited to 40°C. Some operators limit their application to flying leads and jumper umbilicals.

The main considerations for non-metallic hoses and their materials of construction are:

- chemical compatibility with well service fluids;
- permeation of low molecular weight fractions, especially methanol, through the hose liner;
- resistance of hoses to collapse under internal pressure differential caused by cyclic pressurisation of the conduits;
- resistance of hoses to collapse under external hydrostatic pressure especially in deep water with low specific gravity fluids;

- fatigue behaviour of composite tubes and other metal components in dynamic umbilicals; and
- long-term end fitting reliability determined by material stress retention properties.

For polymeric based hoses, material selection should be based upon a detailed evaluation of all fluids to be handled. The annulus bleed system, for example, will be exposed to a mixture of fluids such as production and completion fluids, methanol, and pressure compensating fluid. A hose qualification programme should be considered, including testing of candidate materials in a stressed condition representative of actual working pressure, unless relevant documentation exists. Qualification testing results should provide a basis for service life extrapolation. See also Section 12.4.2.

12.3.2 Metallic Tube Conduits

For umbilicals where the conduits are of the metal tube type, the required resistance to corrosion dictates materials considerations with regard to both the transported fluids (internal) and seawater (external). CRAs are therefore generally preferred for the tubes, in particular seamless or seam welded 25% Cr superduplex stainless steel. Other possible CRA materials recognised in ISO 13628-5 Annex H are seam welded lean duplex and 316L stainless steels.

The principal advantage of seamless tubes relates to the absence of a longitudinal weld and potentially higher integrity. The advantages of seam welded tubes relate to lower cost and longer individual lengths meaning that fewer butt welds are required. The ISO Standard does not distinguish between these options. Some operators however do restrict supply to seamless grades. A disadvantage of 25% Cr superduplex stainless steel is that it is normally available in relatively short lengths, and this requires a large number of butt welds to make up the reels for umbilical manufacture. Strict quality assurance and control including 100% NDT of the welds is required to ensure high reliability. 25%Cr superduplex stainless steel is also susceptible to the formation of detrimental intermetallic phases if the heat treatment during manufacture is not properly controlled.

Zinc clad carbon steel tubes have also been developed and used as carrier conduits for transporting both chemical injection and hydraulic control fluids. These tubes are manufactured in continuous lengths as electric resistance welded (ERW) products from high strength low alloy steels. Zinc sheathing is then extruded over the external surface of the steel tube. This is claimed to provide external corrosion resistance for a life of 30–40 years. Such technology was developed to address the high costs associated with using CRA tubing for very long umbilicals, and has been employed in a number of Gulf of Mexico projects involving long tie-backs.

A key factor in the success of carbon steel tube designs is to ensure adequate internal cleanliness after tubing manufacture until immediately prior to use. The long term internal corrosion resistance of such tubes and the reliability of the seam welds are also important considerations. The seam welded tubes are available in a smaller variety of wall thicknesses, thereby reducing the optimal use of tubes and possibly reducing cost advantage.

To reduce the cost of corrosion resistant materials for umbilical tubes, use has also been made in the Gulf of Mexico of UNS S32001 which is a lean duplex

stainless steel. This is cheaper than 25% Cr superduplex stainless steel and is less susceptible to detrimental intermetallic phases, but it has limited corrosion resistance in seawater and requires an extruded zinc sheath.

The main materials considerations for all the metallic components (tubes and end fittings) in umbilicals are:

- the limited resistance of all grades of stainless steels to corrosion in sea water,
- ensuring electrical continuity for providing CP to all necessary metallic components,
- cathodic protection of the end fittings and tube terminations,
- the susceptibility to hydrogen embrittlement of the materials in their installed condition,
- possible galvanic corrosion effects between different materials in direct electrical contact in a saline conducting environment,
- avoidance of detrimental intermetallics in superduplex stainless steel tubes,
- zinc sheathing thickness on carbon steel or lean duplex tubes to achieve the required design life,
- internal cleanliness of carbon steel tubes,
- the limits for titanium in methanol service,
- fatigue resistance for dynamic umbilicals, and
- effect of accumulated strain from reeling/spooling during manufacture and installation.

A matrix for CRA tube materials that are acceptable for use in subsea umbilicals is included in Annex H of ISO 13628-5. The matrix contains typical minimum requirements for each material type relating to tube manufacture, heat treatment, chemical analysis and mechanical testing, microstructure, dimensions, surface finish, corrosion testing, non-destructive testing, pressure testing, marking and certification.

12.3.3 Umbilical Construction

Armour wires, if used, are usually steel, either galvanised or sheathed in non-metallic material.

The inner and outer sheaths of an umbilical may be either of extruded thermoplastic material, typically polyethylene, polyamide 11 or polyether-based polyurethane, or a helically applied serving (roving of polypropylene or similar fibres).

For dynamic umbilicals where armour wire stability and fixing of attachments (e.g. buoys) are important features, an outer extrusion of high modulus material is preferable.

12.3.4 End Terminations

Hose and tube end termination components are usually specified in CRAs. As a minimum, grade 316 stainless steel is specified, but other more resistant materials, such as superduplex stainless steels are also used. The terminations should be coated externally to minimise anode consumption.

The provision of temporary CP needs to be considered for protection of end fittings during installation, especially for 316 stainless steel or other low PREN alloys. This can be achieved by the use of dummy stab plates attached to an umbilical installation basket (where this is used) that has its own CP. On longer umbilicals where an installation basket is not used, temporary CP anodes can be attached to the termination assembly.

The couplings in the end termination can suffer from galling during assembly prior to installation. The risk of galling can be reduced by using UNS S20910 for the end fitting coupling and UNS S21800 for the hose, but galling problems have been experienced with these materials if the couplings are not properly aligned (noting the recommendation to use these alloys in the solution treated and water quenched condition free from cold work). Use of appropriate anti-galling greases is important.

12.3.5 Bend Stiffeners

Umbilical bend stiffeners fulfil the same purposes as those used for flexible pipe and described in Section 10.5. A typical umbilical bend stiffener is shown in Figure 22.



Figure 22 Typical umbilical bend stiffener

12.4 Materials Problems

12.4.1 Service Experience

Although a variety of metallic and non-metallic materials has been used in service, details of operating experience with them can be limited. In particular, where operating problems have been experienced it is difficult to obtain information as to the exact causes of the problems because of the inaccessibility of the evidence. It is only possible to identify the cause of the problems if the umbilical is retrieved from service. This can be an expensive operation (and may not be feasible if the unit is still functioning to an acceptable level) and is consequently an infrequent activity. However, following a number of failures, retrieval of both non-metallic and metallic tube umbilicals has led to an increased understanding of service problems

12.4.2 Non-Metallic Hoses

For umbilicals containing fibre reinforced thermoplastic hoses, the materials-related problems have been associated principally with inadequate chemical or permeation resistance of the hose liner material to the fluids that they may be required to transport. The permeation problem is particularly associated with methanol, and the chemical resistance problem with very aggressive chemicals. There are well known chemical incompatibilities that need to be avoided, such as polyamide 11 with very low pH fluids and XLPE with aromatic hydrocarbons. There are also uncertain areas with some plastic-chemical couples, e.g. polyamide with aromatics.

The choice of thermoplastic polymer materials available does, however, mean that for most applications a suitable polymer will be available for the intended fluid service.

In addition to the above problems with the basic chemical resistance of polyamides to the various transported chemicals, different problems associated with methanol are also possible. Methanol permeating the wall of a hose may pass into an adjacent hose. The adjacent hoses would generally be carrying different fluids, which may react with the methanol to form a paste. There is circumstantial evidence that such problems with methanol have occurred in practice, and that in extreme circumstances paste has completely blocked chemical hoses. Other evidence suggests that such problems have resulted from the lines being used for conveying different fluids that have reacted with each other, or that reduction in temperature and/or lack of fluid motion has resulted in the formation of waxes and/or particulates. Operational procedures should ensure these potential problems are highlighted and avoided.

Two failures of thermoplastic umbilicals have been associated with methanol permeation through the hose liner material. The failure of the hoses was caused by a number of contributory factors, namely: de-pressuring in between periods of methanol injection, the difference in hydrostatic head of methanol (low) and seawater (high), the rate of methanol permeation, and the reliance of methanol permeation through the hose's outer sheath to equalise pressure in the micro-annulus. The combined effect of these factors produced a sufficiently high pressure differential across the wall of the methanol hose to result in the collapse of the core. Collapse can occur in two different manners, depending on the way in which the pressure differential appears:

- a pressure differential across the combined wall of the hose causes the whole hose to collapse; and
- a pressure differential between the bore of the hose and the micro-annulus of the reinforcing layer causes the collapse of the liner, but not the outer sheath.

The repeated collapse of the hose, following periods of methanol injection, ultimately results in a fatigue failure of the hose. To reduce the risk of collapse, all thermoplastic umbilical cores in methanol injection service should be maintained at a positive pressure and a control interlock should be included such that the methanol injection valves cannot be opened unless the supply line is above a nominal pressure.

Leaching of plasticiser was initially a problem with hoses containing plasticiser but

newer materials have overcome this problem. Permeation problems are also much reduced with low permeation polymer liners.

Fluoropolymer-lined polyamide hoses may perform poorly in service, because the inner fluoropolymer veneer can delaminate from the substrate material. This aspect needs to be considered in any design that uses such materials.

12.4.3 Metallic Tubes

There have been a number of high profile failures of metallic tube umbilicals. These occurred with the early applications of superduplex stainless steel tubes, and were attributed in part to a lack of understanding by the tube suppliers of the demanding quality requirements for subsea umbilical application.

The problems were associated with the quality control of superduplex stainless steel tubing that allowed lengths containing regions of defective material to be installed into long umbilicals. In one case the problem was detected and resolved before placement of the umbilicals on the seabed, but significant costs were incurred due to re-work and schedule delay. In another case tube failure occurred after two weeks service, and the umbilical had to be replaced. The cause of failure was attributed to the presence of localised areas of 20–40% sigma phase at the mid-length of a number of tubes. Cracking occurred at areas of corroded ferrite adjacent to the intermetallic phases and propagated as a result of the reduced ductility. The origin of the problem was traced to interruptions during heat treatment of the tubes that allowed some areas to cool too slowly. Refer to Figure 23.



Figure 23 Brittle failures of superduplex stainless steel umbilical tubing

Experience with subsequent projects has demonstrated that good quality superduplex stainless steel tubing can be manufactured. Since the failures, the main tube suppliers have recognised the need for better QA. Improved furnace assurance systems have been introduced, and eddy current equipment installed to detect sigma phase: levels as low as 2% can be reliably detected. The use of 100% eddy current inspection has been successful in detecting gross amounts of sigma phase due to furnace interruptions, and is an essential part of the overall tube QC.

Tube manufacture and inspection should be based on a comprehensive manufacturing procedure specification and an inspection and test plan agreed with the manufacturer as detailed in ISO 13628-5 para 7.5.6 and EEMUA 218 Section 8. The MPS should deal with the minimum requirements listed in Annex

H of ISO 13628-5, which may be supplemented by specific purchaser requirements. The MPS should be qualified by verification testing, ideally prior to the main production and once qualified no changes should be made to the procedure without agreement or further testing. A comprehensive tracking system is required to ensure that individual tubes can be traced. Surveillance inspection (preferably by inspectors with some metallurgical competence) should be maintained at the supplier for the duration of tube production.

Problems are not normally experienced with production of the hollows for tube manufacture but during tube production for two projects micro-segregation with some associated sigma phase was observed in the tubes. This was caused by a lack of control in the manufacture of the hollow.

Another failure occurred during an umbilical installation as a result of excessive loading from the hydrostatic pressure differential due to the umbilical being flooded too slowly during deployment. This resulted in crushing of the central core of tubes and was compounded by the low ductility caused by the high sigma phase content.

Even with highly corrosion resistant materials, care needs to be taken for elevated temperature duty.

There is one case of microbially induced crevice corrosion in 25% Cr superduplex stainless steel in shallow tropical waters, about 25°C. Although this has been reproduced in laboratory tests it has not been experienced elsewhere in similar environmental conditions. Where this is a concern, one option is to sheath or coat the tubes with a thermoplastic, e.g. PP.

12.4.4 Electric Cable Insulation

Electric cable insulation material should be qualified for all relevant fluids. The materials selected for electrical terminations should be of similar type in order to ensure good bonding between different layers. The material selection for metals and polymers in electrical cables in the outer protection (distribution harness) and in connectors in distribution systems should have qualified compatibility with respect to dielectric fluid/pressure compensation fluid and seawater. The functionality in seawater of the individual barriers relative to the service life should be documented.

13. Instruments

13.1 Introduction

Instruments are usually required somewhere on subsea wellheads, trees, manifolds and flowlines for the measurement of pressures and temperatures. Instruments may also be specified for other applications including single or multiphase flow measurements, for the detection of sand production, for the detection of hydrocarbon leakage, for the passage of a pig, for corrosion monitoring, and for valve position indication.

The reliability of instruments is important since the costs for their replacement after failure is always likely to be high, especially where double block and bleed valve isolation is not provided.[†] Failure of some instruments could lead to loss of containment.

13.2 Materials Selection

Some instruments such as those for pressure and flow measurements are intrusive, hence the same principles of materials selection will apply as for other equipment exposed to both the process environment and to seawater. Non-intrusive instruments include those for temperature measurement, sand detection and pig detection.

Temperature and pressure sensors are sometimes packaged into the same housing.

Pressure sensors normally incorporate a diaphragm assembly that is exposed to the process environment. Alloy 625 or materials of similarly high corrosion resistance are usually specified.

Instrument housings are typically in 316L, duplex stainless steel, Alloy 825 or titanium. As always, electrical continuity with the main structure needs to be assured. Dependent on their size and geometry, these housings may or may not be suitable for the application of an external protective coating.

Flow meters are major pressure containing equipment items, the bodies of which are usually forged or HIP duplex stainless steel as a minimum, subject to the corrosivity of the produced fluids. Reference should be made to Appendix III for guidance on the use of duplex stainless steels for major forged components. Most flow meter designs use stud connections to the piping, thereby avoiding welding. Internals are also CRAs, usually duplex stainless steels or nickel alloys. Cartridge designs permit recovery of the internals for maintenance/change out.

13.3 Materials Problems Encountered

Failures of subsea pressure transducers in duplex stainless steel have been reported. The sensor bodies comprised several sub-assemblies joined by small autogenous TIG welds that had very high ferrite contents. Weld cracking by

[†] See EEMUA Publication 182 (2nd Edition) for requirements for integral block and bleed valve manifolds for subsea use.

hydrogen embrittlement from the CP allowed seawater ingress and loss of functionality, though no loss of hydrocarbon containment.

Some material incompatibility between potting compounds, metallic elements and produced fluids has been mooted after the failure of several sand and corrosion probes. No definitive reason has yet been determined.

14. Protective Coatings and Insulation

14.1 General Comments

External corrosion protection is normally achieved by a combination of coating and cathodic protection.

Surface coatings can be designed for a variety or combination of duties including:

- corrosion protection,
- anti-fouling,
- mechanical protection,
- thermal insulation (see Section 14.3),
- seabed stability (e.g. pipeline concrete coating),
- identification and marking,

Each of the applicable duties needs to be taken into consideration when specifying a subsea coating system. There is no single answer, and each coating system needs to be considered on a case-by-case basis.

As one of the duties of the surface coating system will be to reduce the amount of sacrificial anodes required to protect the installation, it is also recommended to coat stainless steel and CRA surfaces.

14.2 Protective Coatings

14.2.1 Surface Preparation

Good quality surface preparation is crucial to the achievement of maximum coating performance for components continuously immersed in seawater to minimise the likelihood of poor coating adhesion, cathodic disbondment and osmotic blistering. Coating systems are only effective if they adhere properly to the surface to which they are applied therefore removal of surface imperfections and contaminants is necessary as well as achieving an appropriate anchor profile.

Surfaces will typically be prepared in accordance with ISO 8501-3 to deal with surface imperfections that may affect the ability to achieve the required surface cleanliness and profile – sharp edges in particular should be removed or ground to an acceptable radius as these features can significantly affect the performance of the applied coating system.

Prior to blast cleaning, surfaces will need to be cleaned to remove contaminants such as oil, grease, dust, soluble salts, etc. Thereafter, grit blast cleaning to achieve an ISO 8501-1 Sa 2½ quality of surface cleanliness is typically required to achieve optimum coating adhesion although certain coating systems require Sa 3 surface preparation

Achievement of an appropriate anchor profile is also crucial to coating adhesion and performance. The anchor profile is determined by the blasting medium and equipment used as well as the coating system, the underlying substrate and, in some cases, with the required coating function. For CRAs, high quality non-metallic abrasives are typically used to avoid contamination of the surface.

Reference should be made to the ISO 8501 and ISO 8503 series of standards for

required levels of cleanliness and typical surface profiles applicable to different coating systems.

14.2.2 Selection of Coatings

14.2.2.1 General Considerations

Considerations for the selection and design of subsea coating systems, including field joint coating systems, need to take account of a variety of factors, including:

- the level of cathodic protection on the coated structure,
- the expected operating temperature,
- the thermal gradient across the coating,
- the expected operating depth,
- seabed conditions,
- substrate material,
- periodic retrieval,
- intended duty of the coating,
- coating design life,
- installation technique, and
- in-service maintenance.

It is common that coating systems need to satisfy several of the above listed design considerations. This Section aims to guide the designer in the decision process for coating selection.

14.2.2.2 CP Compatibility

The cathodic protection designs for subsea structures and pipeline systems need to take into account the design and quality control of applied protective coating systems.

General cathodic protection requirements for subsea structures and pipeline systems are described in Chapter 4 of this document.

Given that subsea structures and pipelines will normally be cathodically protected, it is important to assess the resistance of the prospective coating system to cathodic disbondment. As such, each coating system should be tested for cathodic disbondment resistance in accordance with the requirements of the ISO 21809 for pipeline coatings and ISO 15711 for paints.

TSA coatings can provide both barrier coating properties and CP to small exposed areas. They also have good current attenuation properties. Any premature consumption of aluminium CP anodes can cause problems as the TSA coating becomes the anode and can be consumed quickly.

14.2.2.3 Operating Temperature

The maximum operating temperature of components will normally be used by designers to select the most appropriate types of coatings.

For pipelines, flowlines or jumpers that do not require wet subsea thermal insulation there are a range of coatings typically used depending on maximum expected operating temperature:

- 3-layer FBE/PP is typically accepted up to 110°C.
- Single or dual layer FBE (with or without concrete weight coat) is typically accepted up to 95°C.
- 3-layer FBE/PE is typically accepted up to 80°C.
- Elastomeric coatings up to 80°C.

For higher temperatures or for newer products without a demonstrable long term track record, laboratory and/or field qualification test programmes should be considered.

For uninsulated subsea equipment there are several choices of coatings that have successfully been used to provide corrosion protection in conjunction with cathodic protection, e.g. multi-component liquid coatings, such as epoxies, urethanes, etc., or TSA. Confirmation of the temperature limitations of the liquid coatings through laboratory qualifications can be considered.

When any equipment, pipelines, flowlines, jumpers or components are to be insulated, the coating system needs to be compatible with the insulation system and suitable for the maximum operating temperature and should be chosen in conjunction with the insulation supplier. Typically, FBE is used for insulated pipelines, flowlines or jumpers while multi-component liquid coatings are normally chosen beneath insulated components.

14.2.2.4 Operating Depth

The prospective coating supplier should be consulted regarding intended operating depth. The designer should require demonstrable proof that the coating system will not be adversely affected by depth to the detriment of either coating integrity or deterioration of required properties (e.g. thermal insulation). The first stage in coating deterioration is likely to be moisture uptake, and this will probably be influenced by the hydrostatic pressure.

Operating depth also becomes relevant if a coating with thermal insulating properties is under consideration, as hydrostatic pressure can result in compression of the insulation, leading to a reduction in the resistance to heat transfer.

14.2.2.5 Seabed Conditions

Seabed conditions and the nature of seabed sediments may influence coating selection. The compatibility of proposed coating systems with seabed mud or sediments should be considered.

14.2.2.6 Substrate Material

The coating characteristics of carbon steel and most commonly used CRAs are well understood and the majority of coatings can be reliably applied to either substrate.

Issues of surface preparation and assessment of coated surface characteristics (e.g. adhesion) need to form part of the coating selection process irrespective of what substrate surfaces are coated.

14.2.2.7 Periodic Retrieval

Typical coating systems for different duties are given in Table 5 below. The supplier of the specific coating should be consulted to help determine the temperature range and suitable service conditions for their system. However, general guidance is given in the table below:

Table 5 Typical subsea coating systems

Generic Coating Type	Typical Thickness of Full System (µm)	Max. Op. Temp (°C)	Comments
Typical equipment coating systems			
Immersion-grade epoxy	400	80 ¹	Multi-coat system
Phenolic or novalac modified epoxy	400	100 ¹	
Glassflake epoxy	500	70 ¹	Single coat enhanced damage resistance ²
Glassflake polyester	500	90	
Glassflake vinyl esters	500	150	
TSA plus sealer coat	200	-	Now commonly considered ³
Typical pipeline coating systems			
Fusion bonded epoxy	450	90 ¹	
TSA plus sealer coat	200	-	Now commonly considered ³
3-layer polypropylene	3000+	110 ¹	Multi-coat enhanced damage resistance ⁴
3-layer polyethylene	3000+	80	
Elastomeric	3000+	80	Typically used for steel/CRA risers
Others			
Amine adduct cured epoxy	400	80 (120 ¹)	Multi-coat system
Phenolic modified epoxy	400	100 (130 ¹)	
Elastomeric polyurethane	3000	70	Single coat enhanced damage resistance
Fusion bonded epoxy	450	80 (110 ¹)	
Glassflake epoxy	500	70 (120 ¹)	Single coat enhanced damage resistance ²
Glassflake polyester	500	90	
Glassflake vinyl esters	500	150	
Thermally sprayed aluminium plus sealer	200	200	Now commonly considered ³
3-layer polypropylene	3000+	130 ¹	Multi-coat enhanced damage resistance ⁴
3-layer polyethylene	3000+	75	

Notes:

1. New formulations may extend the specified temperature range.
2. Glass flake systems can delaminate when exposed to CP.
3. TSA coatings have good tolerance to mechanical damage. They are used under strakes and other clamp-on components to avoid possible shielding

and coating damage during installation. Other common uses are on risers, wellheads, stress joints, and keel joints at bottom of spars.

4. May also be considered where thermal insulation is required.

14.2.2.9 Coating Design Life

The required design life for the coating system should be stated in the design premise. For subsea developments, the coating system should be considered as a 'whole life' and essentially 'maintenance free' system, and selected on the basis of the installation design life.

14.2.2.10 Installation Technique

A well thought out and designed coating system could fail prematurely if the method of installation for the coated component and avoidance of excessive damage is not taken into consideration. There is no single answer to this problem. The solution may lie in coating system selection or in the development and implementation of suitable procedures aimed at minimising such damage. Limited mechanical damage is usually tolerable, as protective coatings are inevitably used in conjunction with cathodic protection.

14.2.2.11 In-service Maintenance

Once a coated structure or component has been placed on the seabed, it is usually there for the full design life of the installation. The coating system design needs to take this into account (see Section 14.2.2.9). However, if periodic retrieval of the subsea system is expected, then adoption of a similar maintenance philosophy to that adopted for topsides coating selection can be applied. Irrespective of this, the coating system selected needs to be suitable for subsea duty and sufficiently robust to withstand mechanical abuse during installation and retrieval (see Section 14.2.2.7).

14.2.3 Pipeline Field Joint Coatings

14.2.3.1 Introduction

To maintain integrity of the pipeline, the performance characteristics of both the field joint coating (FJC) and the mainline factory applied coating should be equivalent.

The selection of FJC systems should be assessed in a similar manner to the mainline factory applied coating system as described in Section 14.2.2, taking into account any other project specific design requirements, and need to be compatible with the factory applied coating system.

14.2.3.2 Current Field Joint Coating Systems

FJC systems are described in ISO 21809-3. In Table 6 below are some of the common FJC systems currently used.

14.2.3.3 Qualification Testing

Qualification testing of both mainline factory applied coating and FJC systems is essential to qualify the applicator's facilities, procedures, processes and materials

Table 6 Field joint coating systems

Mainline factory applied coating	FJC system
FBE	FBE layer only (min. 350 microns (µm)) - steel substrate blast cleaned to Sa 2½
3LPP	FBE layer (min. 150 microns (µm)), with 3mm PP applied by flame spraying, or extrusion (e.g. injection moulding) - steel substrate blast cleaned to Sa 2½
	FBE layer (min. 150 microns (µm)), an intermediate layer of PP adhesive with 2–3 mm PP wrapping tape applied on top - steel substrate blast cleaned to Sa 2½
3LPE	FBE layer (min. 150 microns (µm)), an intermediate layer of PE adhesive with 2–3mm PE heat shrink sleeve applied on top
Elastomeric	Elastomeric sleeve of same type as mainline coating, wrapped on top of primer, with vulcanised bonding to parent coating - steel substrate blast cleaned to Sa 2½

and to demonstrate that the proposed coating system should be suitable for the operating and installation conditions. This qualification process is addressed in ISO 21809-3.

For FJC systems, the procedure qualification tests should be carried out on representative welded joints to simulate actual coating installation/application conditions during pipeline fabrication and or installation. Compatibility and adhesion between the different materials on the field joint need to be assured.

14.2.3.4 Coating of Fasteners

Materials selection issues related to fasteners, including the coating of bolting components, are addressed in Section 9.2.2 above.

14.3 Thermal Insulation

14.3.1 Introduction

Thermal insulation on subsea production and pipeline systems is often required for flow assurance purposes, e.g. to avoid wax deposition or hydrate formation. The two key requirements of this insulation are to provide a sufficiently low heat transfer rate in flowing conditions and have sufficient heat capacity to maintain the fluids above a threshold temperature in shutdown conditions. Insulation also needs to be able to withstand all loads imposed upon it and maintain these properties throughout field life.

Operating temperature and water depth are important design considerations. Organic insulation materials currently have an upper temperature threshold of between 100°C and 150°C. For higher temperatures, consideration may need to be given to inorganic insulation materials as used in pipe-in-pipe designs where the insulation medium is located within the annulus.

At the time of writing, ISO/CD 12736 for subsea wet insulation is being drafted.

14.3.2 Selection of Thermal Insulation Systems

14.3.2.1 General Considerations

Considerations for the selection and design of subsea thermal insulation systems, including field joint coating systems, need to take account of a variety of factors, including:

- Thermal performance, including cool down time.
- Water absorption characteristics.
- Expected service and water temperatures.
- Expected operating depth.
- Seabed conditions.
- Design life.
- Installation technique.
- Resistance to impact, thermal shock and abrasion.
- Expected thermal expansion.
- Mechanical properties such as compressive, tensile and shear strengths.
- Anti-corrosion requirements.
- In-service maintenance.

14.3.2.2 Thermal performance

Key thermal performance characteristics to be considered include:

- **Thermal conductivity ('k-value').** This property is critical in the assessment of cool-down times during shutdowns and insulation system design. The lower the thermal conductivity the better the insulating medium.
- **Heat transfer coefficient ('U-value').** This is based on the pipe outside diameter and is the key parameter used to characterise the performance of a particular insulation system.
- **Water absorption.** Over time, ingress of water into any insulation will have a marked effect on its thermal performance (U-value degradation).
- **Density.** Thermal characteristics are inherently related to density. It is also an important parameter for pipeline/flowline stability and riser response.
- **Long-term performance at depth and temperature.** Performance parameters such as ageing resistance in 'hot-wet' or 'hot-dry' conditions, and compressive creep are important characteristics. Corrosive species that are leachable or generated by hydrolysis of the coating also need to be considered.
- **Anti-corrosion performance.** Adherence to the mainline and FJ systems as well as coating and compatibility with cathodic protection systems is crucial to long-term operation and integrity. Delamination and water ingress can be major problems if the insulation system shields the substrate from cathodic protection.

14.3.2.3 Available Systems

The selection of typical insulation systems and U-values over life of field are summarised in Table 7 below.

Table 7 Typical subsea insulation systems

Generic Material	Typical Thermal Conductivity (W/mK)	U-value for 12 in dia. pipeline (W/m ² K)	Typical Application & Comments
Bare steel (no insulation)	–	1300	Ambient water with free convection
Solid PE	0.25–0.4	10.2	Integral 'wet' systems
Solid PP	0.22	10	
Solid PU	0.19	5.1	
EPDM	0.26–0.30	10	
Polypropylene foam	0.14–0.18	4	
Syntactic PP	0.16–0.18	3	
Syntactic PU	0.11	2.7	
Syntactic Epoxy	0.09–0.13	2	Rigid half shells
High Density PUF	0.055	1.5	Encased/encapsulated
Fly ash/microspheres	0.10	0.75	Pipe-in-pipe (PiP) systems
Mineral wool	0.026	0.7	
PIR foam	–	0.8	
PUF	0.025	0.7	
Microporous silica	0.02	<0.7	
Vacuum	0	0	

Note: typical thermal properties for a 12 inch dia. pipeline system with 45 mm of applied insulation are included only as a comparison between systems and should not be used for design purposes).

Guidance on typical application ranges for these systems is set out in Table 8.

14.3.3 Manufacturing and Installation Considerations

An appreciation of manufacturing and installation methods is required in the design and selection of insulation systems for subsea pipelines, flowlines and equipment installed on the seabed.

Insulated pipelines and flowlines will require inclusion of field joints. Ideally, these should be of the same type and design as the primary insulation system. However a compromise is frequently required, the use of an inferior system often being necessitated. The design and qualification of field joints and associated insulation termination arrangements should be assessed in a similar manner to the primary insulation system (Sections 14.3.2.2 and 14.3.5).

If installation and/or field joint preparation is expected to be performed at low temperature, then this should be considered in the testing and qualification phase. Field joint systems should also be designed to provide a smooth transition for passing over rollers during reel laying operations.

Pipe-in-pipe insulation systems use forged bulkheads to connect the inner and outer pipes. These provide structural continuity, and can mitigate axial thermal

Table 8 Typical application ranges of subsea insulation systems

Generic Material	Max Depth Capability (m)	Temperature Tolerance (°C)	
		Dry	Hot-wet
Solid PE	Unlimited	120	120
Solid PP	Unlimited	100–140	100
Solid PU	Unlimited	100	70
EPDM	Unlimited	130	150
Polypropylene foam	600	100–115	100
Syntactic PP	1000–3000	100*	100
Syntactic PU	1000–3000	100	70
Syntactic Epoxy	1000–3000	100*	70
Fly ash/microspheres	Limited by PiP system	>200	Limited by PiP system
Mineral wool			
PIR foam		100	100
PUF		150	150
Microporous silica		>200	Limited by PiP system
Vacuum		Unlimited	

** Note: Syntactic foams employing glass spheres embedded in polypropylene and heat resistant epoxies have been shown to be effective up to around 150°C.*

expansion stresses. The consequences of penetration of the outer steel pipe should be considered in design. This may determine the frequency of bulkhead and/or water stop placement to minimise overall insulation system performance deterioration.

An alternative means of temperature control that can be used in conjunction with insulation for hydrate or wax control is Direct Electrical Heating (DEH). The DEH system utilizes heat generated by applying AC current to the pipe to be heated with the single core supply cable attached externally to the pipeline as a piggyback installation. The heating system is electrically connected to surrounding seawater through several sacrificial anodes to provide grounding. DEH systems have been installed in the Norwegian sector.

14.3.4 Thermal Insulation of Subsea Production and Process Equipment

The complex shape of manifold piping and trees precludes the use of 'production line' approaches used for pipeline insulation. The extent of insulation can be variable, with equipment such as piping flanges and flanged components (valves) remaining bare for reasons of accessibility, inspection and maintenance.

The selection of insulation systems is governed by the same criteria outlined above. The insulation may be applied as segments (e.g. half shells) or by casting.

Given these application challenges, it is important that the equipment be provided with adequate corrosion coating prior to insulation, to protect both intentionally exposed surfaces and those beneath the insulation against the seawater.

14.3.5 System Qualification and Performance Verification

System qualification and performance verification is typically achieved through a combination of materials and system tests.

System qualification tests, carried out on both pipe and field joint coating should include:

- Suppliers' statement of baseline U-value and k-value of pipe coating and field joint coating.
- Provision of suppliers'/installers' manufacturing and quality plan including test protocols.
- A verification scheme to ensure that required tests are conducted, and that the results are acceptable
- Simulated service test to confirm heat transfer characteristics of system.
- Simulated installation tests, e.g. survival test, static bend test for reeling, tensioner simulation, etc.
- Cyclic bend test for dynamic applications
- Ring shear test.
- Thermal shock tests.

Suppliers should document relevant materials properties under combinations of temperature and pressure relevant to the application. For wet insulation, this should include:

- **Primary properties:** thermal conductivity, specific heat, hydrostatic strength, ageing resistance, water absorptivity.
- **Secondary properties:** abrasion resistance, adhesiveness, bending resistance, bulk modulus, resistance to cathodic disbondment, resistance to compressive creep, impact resistance, density, fatigue resistance, friction coefficient; shear, tensile and compressive properties; thermal expansion coefficient, thermal shock resistance, glass transition temperature of resins, and resistance to biological effects and UV.

For dry insulation within a pipe-in-pipe annulus, materials properties should include:

- **Primary properties:** thermal conductivity, specific heat, ageing resistance.
- **Secondary properties:** bending resistance, resistance to compressive creep, density, dimensional stability; shear, tensile and compressive properties; thermal expansion, thermal shock resistance.

There should also be a description of bulkheads and internal seals intended to limit effect of flooding.

In all cases, the selection process and qualification acceptance criteria should consider residual insulation. Minimum acceptable properties should be stated where possible. The supplier should demonstrate heat transfer characteristics at end of field life, e.g. by demonstrating constant properties or a slow and predictable decline.

Appendix I Reference Documents

The documents listed below, in alphabetical order of the publishing organisation, are referred to in the main text of and appendices to this Publication. A glossary of abbreviations is given in Appendix VIII.

API

RP 2RD	Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)
Spec 5L	Line Pipe
Spec 5LC	CRA Line Pipe
Spec 5LCP	Coiled Line Pipe
Spec 5LD	CRA Clad or Lined Steel Pipe
Spec 6A	Wellhead and Christmas Tree Equipment
Spec 6A718	Specification of Nickel Base Alloy 718 (UNS N07718) for Oil and Gas Drilling and Production Equipment
Spec 14A	Subsurface Safety Valve Equipment
RP 14B	Design, Installation, Repair and Operation of Subsurface Safety Valve Systems
RP 14E	Design and Installation of Offshore Production Platform Piping Systems
RP 15S	Qualification of Spoolable Reinforced Plastic Line Pipe
RP 17A	Design and Operation of Subsea Production Systems (<i>co-branded ISO 13628-1</i>)
RP 17B	Flexible Pipe (<i>contains the full text of ISO 10420</i>)
RP 17C	TFL (Through Flowline) Systems (<i>co-branded ISO 13628-3</i>)
RP 1111	Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)
Spec 17D	Subsea Wellhead and Tree Equipment
Spec 17E	Specification for Subsea Umbilicals (<i>co-branded ISO 13628-5</i>)
Spec 17F	Specification for Subsea Production Control Systems (<i>co-branded ISO 13628-6</i>)
RP 17G	Design and Operation of Completion/Workover Riser Systems
RP 17H	Remotely Operated Vehicles (ROV) Interfaces on Subsea Production Systems
[RP 17I	Installation of Subsea Umbilicals (<i>withdrawn</i>)]
Spec 17J	Unbonded Flexible Pipe
Spec 17K	Specification for Bonded Flexible Pipe
Spec 17TR1	Evaluation Standard for Internal Pressure Sheath Polymers for High Temperature Flexible Pipes
TR 17TR2	The Ageing of PA-11 in Flexible Pipes
Std 1104	Welding of Pipelines and Related Facilities

ASME

B16.28	Wrought Steel Buttwelding Short Radius Elbows and Returns
B16.34	Valves: Flanged, Threaded, and Welding End
B16.5	Pipe Flanges and Flanged Fittings: NPS ½ through 24
B16.9	Factory-Made Wrought Buttwelding Fittings
B31.3	Process Piping
B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
B31.8	Gas Transmission and Distribution Piping Systems

ASME Boiler and Pressure Vessel Code

- Sec VIII Rules for Construction of Pressure Vessels (Div 1, and Div 2—Alternative Rules)
- Sec IX Welding and Brazing Qualifications

ASTM

- A182 Standard Specification for Forged or Rolled Alloy-Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service
- A193 Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service
- A194 Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both
- A240 Standard Specification for Chromium and Chromium-Nickel Stainless Steel Plate, Sheet, and Strip for Pressure Vessels and for General Applications
- A264 Specification for Stainless Chromium-Nickel Steel-Clad Plate
- A265 Standard Specification for Nickel and Nickel-Base Alloy-Clad Steel Plate
- A269 Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service
- A312 Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes
- A320 Standard Specification for Alloy-Steel Bolting Materials for Low-Temperature Service
- A350 Standard Specification for Carbon and Low-Alloy Steel Forgings, Requiring Notch Toughness Testing for Piping Components
- A352 Standard Specification for Steel Castings, Ferritic and Martensitic, for Pressure-Containing Parts, Suitable for Low-Temperature Service
- A358 Standard Specification for Electric-Fusion-Welded Austenitic Chromium-Nickel Stainless Steel Pipe for High-Temperature Service and General Applications
- A453 Standard Specification for High-Temperature Bolting Materials, with Expansion Coefficients Comparable to Austenitic Stainless Steels
- A606 Standard Specification for Steel, Sheet and Strip, High-Strength, Low-Alloy, Hot-Rolled and Cold-Rolled, with Improved Atmospheric Corrosion Resistance
- A694 Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service
- A789 Standard Specification for Seamless and Welded Ferritic / Austenitic Stainless Steel Tubing for General Service
- A790 Standard Specification for Seamless and Welded Ferritic/Austenitic Stainless Steel Pipe
- A860 Standard Specification for Wrought High-Strength Low-Alloy Steel Butt-Welding Fittings
- A928 Standard Specification for Ferritic/Austenitic (Duplex) Stainless Steel Pipe Electric Fusion Welded with Addition of Filler Metal
- B423 Standard Specification for Nickel-Iron-Chromium-Molybdenum-Copper Alloy (UNS N08825 and N08221) Seamless Pipe and Tube
- B424 Standard Specification for Ni-Fe-Cr-Mo-Cu Alloy (UNS N08825 and UNS N08221) Plate, Sheet, and Strip

B443	Standard Specification for Nickel-Chromium-Molybdenum-Columbium [niobium] Alloy (UNS N06625) and Nickel-Chromium-Molybdenum-Silicon Alloy (UNS N06219) Plate, Sheet, and Strip
B444	Standard Specification for Nickel-Chromium-Molybdenum-Columbium [niobium]Alloys (UNS N06625 and UNS N06852) and Nickel-Chromium-Molybdenum-Silicon Alloy (UNS N06219) Pipe and Tube
B673	Standard Specification for UNS N08904, UNS N08925, and UNS N08926 Welded Pipe
B705	Standard Specification for Nickel-Alloy (UNS N06625, N06219 and N08825) Welded Pipe
B725	Standard Specification for Welded Nickel (UNS N02200/UNS N02201) and Nickel Copper Alloy (UNS N04400) Pipe
D665	Standard Test Method for Rust-Preventing Characteristics of Inhibited Mineral Oil in the Presence of Water
E527	Standard Practice for Numbering Metals and Alloys (UNS)
E1961	Standard Practice for Mechanized Ultrasonic Examination of Girth Welds Using Zonal Discrimination with Focused Search Units
G42	Standard Test Method for Cathodic Disbonding of Pipeline Coatings Subjected to Elevated Temperatures
G95	Standard Test Method for Cathodic Disbondment Test of Pipeline Coatings (Attached Cell Method)

BSI

BS 4515	Specification for Welding of Steel Pipelines on Land and Offshore— Pt 1: Carbon and Carbon Manganese Steel Pipelines Pt 2: Duplex Stainless Steel Pipelines
BS 7910	Guide on Methods for Assessing the Acceptability of Flaws in Metallic Structures
BS EN 287-1	Qualification Test of Welders. Fusion Welding— Pt 1:Steels
BS EN 473	General Principles for Qualification and Certification of NDT Personnel
BS EN 719	Welding Co-ordination. Tasks and Responsibilities
BS EN 10088-2	Stainless Steels - Part 2. Technical Delivery Conditions for Sheet/Plate and Strip of Corrosion Resisting Steels for General Purposes
BS EN 13445	Unfired Pressure Vessels
BS EN 14161	Petroleum and Natural Gas Industries. Pipeline Transportation Systems
PD 5500	Specification for Unfired Fusion Welded Pressure Vessels
PD 8010-2	Code of Practice for Pipelines— Pt 2: Subsea Pipelines

CSA

Z662	Oil and Gas Pipeline Systems
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DNV

OS F101	Submarine Pipeline Systems
OS F201	Dynamic Risers
RP B401	Cathodic Protection Design
RP F112	Design of Duplex Stainless Steel Subsea Equipment Exposed to Cathodic Protection
RP F201	Design of Titanium Risers
RP O501	Erosive Wear in Piping Systems

EEMUA

- EEMUA 182 Specification for Integral Block and Bleed Valve Manifolds for Direct Connection to Pipework (*2nd edition, 2004*)
- EEMUA 218 Quality Requirements for the Manufacture and Supply of Duplex Stainless Steels

EFC

- EFC 16 Materials Requirements for Carbon and Low Alloy Steels for H₂S-Containing Environments in Oil and Gas Production
- EFC 17 Corrosion Resistant Alloys for Oil and Gas Production: Guidance on General Requirements and Test Methods for H₂S Service
- EFC 23 CO₂ Corrosion Control in Oil and Gas Production
- EFC 39 The Use of Corrosion Inhibitors in Oil & Gas Production (*published in 2004*)

Energy Institute

Guidelines for the Management of Integrity of Subsea Facilities

GB Health and Safety Executive

Research Report 129 Review of external stress corrosion cracking of 22%Cr duplex stainless steel.

Research Report 115 Erosion in elbows in hydrocarbon production systems: Review document.

ISO

- 3183 P&NGI — Steel Pipe for Pipelines — Technical Delivery Conditions — Part 2: Pipes of Requirements Class B
Part 3: Pipes of Requirement Class C (*also available as ISO 3183-3*)
- 3834 Quality Requirements for Fusion Welding of Metallic Materials
- 4042 Fasteners — Electroplated Coatings
- 4624 Paints and Varnishes — Pull-off Test for Adhesion (*also available as ISO 4624*)
- 8501-1 Preparation of Steel Substrates Before Application of Paints and Related Products — Visual Assessment of Surface Cleanliness — Pt 1: Rust Grades and Preparation Grades of Uncoated Steel Substrates and of Steel Substrates after Overall Removal of Previous Coatings (*also available as ISO 8501-1*)
- 8503 Preparation of steel substrates before application of paints and related products — Surface roughness characteristics of blast-cleaned steel substrates
- 10420 P&NGI — Flexible Pipe Systems for Subsea and Marine Riser Applications (*superseded by ISO 13628-11: 2007*)
- 10423 P&NGI — Drilling and Production Equipment—Wellhead and Christmas Tree Equipment (*also available as ISO 10423*)
- 13628 P&NGI — Design and Operation of Subsea Production Systems— (*also available as ISO 13628-1, etc*)
Pt 1: General Requirements and Recommendations
Pt 2: [Unbonded] Flexible Pipe Systems for Subsea and Marine Applications

- Pt 3: Through Flowline (TFL) Systems
- Pt 4: Subsea Wellhead and Tree Equipment
- Pt 5: Subsea Umbilicals
- Pt 6: Subsea Production Control Systems
- Pt 7: Completion/ Workover Riser Systems (*issued 2005*)
- Pt 8: Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems
- Pt 9: Remotely Operated Tool (ROT) Intervention Systems
- Pt 10: Specification for Bonded Flexible Pipe
- Pt 11: Flexible Pipe Systems for Subsea and Marine Applications
- Pt 15: Subsea Structures and Manifolds
- 13703 P&NGIs — Design and Installation of Piping Systems on Offshore Production Platforms (*also available as ISO 13703*)
- 13847 P&NGI — Pipeline transportation systems -- Welding of pipelines
- 14723 P&NGI — Pipeline Transportation Systems—Subsea Pipeline Valves (*also available as ISO 14723*)
- 14731 Welding coordination — Tasks and responsibilities
- 15156 P&NGI — Materials for Use in H₂S-Containing Environments in Oil and Gas Production (*also available as ISO 15156; see also NACE MR0175*)
 - Pt 2: Cracking-Resistant Carbon and Low Alloy Steels, and the Use of Cast Irons
 - Pt 3: Cracking-Resistant CRAs (Corrosion-Resistant Alloys) and Other Alloys
- 15589-2 P&NGI — Cathodic Protection of Pipeline Transportation Systems—Part 2: Offshore Pipelines
- 15590-1 P&NGI — Induction Bends, Fittings and Flanges for Pipeline Transportation Systems—Pt 1: Induction Bends
- 15614-1 Specification and Qualification of Welding Procedures for Metallic Materials — Welding Procedure Test—Part 1: Arc and Gas Welding of Steels and Arc Welding of Nickel and Nickel Alloys (*also available as ISO 15614-1*)
- 15663-1 P&NGI — Life Cycle Costing — Pt 1: Methodology (*also available as ISO 15663-1*)
- 15711 Paints and varnishes — Determination of resistance to cathodic disbonding of coatings exposed to sea water
- 21457 Materials Selection and Corrosion Control for Oil and Gas Production Systems
- 23936 P&NGIs — Non-metallic materials in contact with media related to oil and gas production

MSS

- SP-44 Steel Pipeline Flanges
- SP-75 Specification for High Test Wrought Butt Welding Fittings

NACE

- MR0175 P&NGI—Materials for Use in H₂S-Containing Environments in Oil and Gas Production (*co-branded ISO 15156; formerly titled Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment*)
- RP0176 Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production
- Report 1D199 Internal Corrosion Monitoring of Subsea Production and Injection Systems

Report 1F192	Use of Corrosion Resistant Alloys in Oilfield Environments
Report 6A194	Surface Preparation Overview for Electroless Nickel Coatings
Report 6A287	Electroless Nickel Coatings
Report 6A294	Quality Evaluation of Electroless Nickel Coatings
Report 7L192	Cathodic Protection Design Considerations for Deep Water Projects
TM0103	Laboratory Test Procedures for Evaluation of SOHIC Resistance of Plate Steels Used in Wet H ₂ S Service
TM0177	Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking and Stress Corrosion Cracking in H ₂ S Environments
TM0198	Slow Strain Rate Test Method for Screening Corrosion-Resistant Alloys (CRAs) for Stress Corrosion Cracking in Sour Oilfield Service
TM0284	Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking

NORSOK

M-001	Materials Selection
M-503	Cathodic Protection
M-506	CO ₂ Corrosion Rate Calculation Model
M-630	Material Data Sheets for Piping
M-710	Qualification of Non-metallic Sealing Materials and Manufacturers

Oil & Gas UK

State of the Art Report on Flexible Pipe Integrity and Guidance Note on Monitoring Methods and Integrity Assurance for Unbonded Flexible Pipes (2010)



EEMUA Publications for the Offshore Industry include:

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- Guide to the production testing of valves for the energy, process, oil and gas industries. EEMUA Publication No. 205, 2008, ISBN 0 85931 151 1
- Quality requirements for the manufacture and supply of duplex stainless steels. Publication No. 218, 2010, ISBN 978 0 85931 175 5

Appendix II Typical Sour Service (H₂S Partial Pressure) Limits for Duplex and Weldable Martensitic Stainless Steels

II.1 ISO 15156/NACE MR0175 Recommendations

ISO 15156/NACE MR0175 includes some recommended limits of H₂S partial pressures for the avoidance of sulphide stress cracking, as follows:

Duplex stainless steel (i.e. PREN/PREw 30 to 40 and Mo ≥ 2%): 0.10 bar (abs)
Superduplex stainless steel (i.e. PREN/PREw > 40 and < 45): 0.20 bar (abs).

II.2 Other Typical Limits

Typical H₂S partial pressure limits currently considered acceptable by some users for avoidance of sulphide stress cracking are as follows:

13% Cr steel (weldable): 0.008 bar (abs) at pH 3.5 and higher
Note: These values apply to the 13Cr/5.5Ni/2.5Mo variants of weldable 13Cr alloys. At higher levels of pH it is likely that significantly higher levels of H₂S could be tolerated.

22% Cr Duplex stainless steel: 0.10 bar (abs) at pH 3.5 and higher

25% Cr Superduplex stainless steel: 0.25 bar (abs) at pH 3.5 to 4.5
 0.50 bar (abs) at pH greater than 4.5.

Note: The limits for duplex stainless steel were largely developed for downhole tubing grades. For applications involving welding, further qualification for the field-specific conditions is recommended.

Appendix III Duplex Stainless Steels for Subsea Piping, Flowlines, and Associated Components (Excluding Fasteners)

III.1 Introduction

Duplex stainless steels (both 22% Cr and 25% Cr alloys) are often considered to be ideal materials for use subsea, and have been used for a variety of equipment types. Their favourable combination of strength, toughness, weldability, and corrosion and SCC resistance has been used to great advantage for many years in surface and topside facilities, especially for process and utility piping systems. Some of the proprietary grades of the 25% Cr alloys have been specifically formulated for optimum pitting and crevice corrosion resistance in seawater; these have become known as 'superduplex'. Although there have been a few recorded failures of duplex stainless steels in surface equipment, the general performance of these materials has been satisfactory, and they continue to be the first choice for many such applications.

Five areas of concern related to the use of duplex stainless steels, whether for surface or subsea application, require particular attention during design. These are:

- The limits of application in sour (H₂S) service.
- Low design temperatures associated with gas blowdown, typically limited to a minimum of –50°C.
- Welding design and qualification to ensure that a satisfactory ferrite–austenite phase balance is achieved in the weld zones, and that the precipitation of tertiary phases such as nitrides and intermetallics is avoided.
- Control of component heat treatment to achieve a satisfactory microstructure.
- Dimensional stability of heavy section components during machining due to 'cold creep' at locations of high residual stress.

The relative advantages of duplex stainless steels over other CRAs have already been exploited in many subsea projects. Perhaps the most frequent application has been manifold piping and flowline systems, sometimes including the valves and ancillary equipment. The excellent corrosion and erosion resistance in most process fluids has enabled compact subsea designs to be utilised. Piping layout and overall manifold dimensions have, as a consequence, been substantially reduced, facilitating deployment.

The main additional areas of concern for duplex stainless steels used subsea are:

- external corrosion by sea water; and
- external hydrogen embrittlement and cracking caused by CP systems.

While it is generally agreed that the 22% Cr grades require painting and CP in order to avoid localised corrosion, especially at crevices, the 25% Cr grades do not strictly require CP if the operating temperatures are low, typically less than 45°C. However, it is not usually practicable to electrically isolate individual items from the rest of the equipment/structure, hence 25% Cr duplex stainless steel components are also usually painted and cathodically protected.

The protective potential for duplex stainless steels to avoid weight-loss corrosion subsea is around -400 mV vs Ag/AgCl/sea water, whereas the carbon steel structural components require potentials more negative than -800 mV for full protection. In practice both carbon steel and multi-material assemblies can be polarised to potentials as negative as -1050 mV when protected by sacrificial aluminium or zinc anodes, particularly if the assemblies are painted.

III.2 Hydrogen Embrittlement and Cracking

III.2.1 Background

It has long been recognised that duplex stainless steels can suffer hydrogen cracking. The failure of a 25% Cr cold worked downhole tubing string in the North Sea in the 1980s was a notable early example of the problem. This tubing material suffered a brittle failure after the tubing had been pulled to the surface and allowed to cool. Failure was attributed to cathodic hydrogen charging of the hot tubing string by direct contact with the carbon steel casing, and the subsequent embrittlement of the material at ambient temperatures. There has also been a small number of weldment failures associated with hydrogen cracking due to the presence of relatively high hydrogen levels in regions of high ferrite, and failures of 25% Cr fasteners.

Within the last fifteen years or so, several more incidents of hydrogen cracking of duplex stainless steel subsea equipment occurred in the North Sea, in both the UK and Norwegian sectors. In two separate incidents, 25% Cr superduplex connector hub forgings cracked through-wall, refer to Figure 24. In other incidents, cracks at aluminium anode doubler plate fillet welds caused failures in 22% Cr duplex stainless steel pipelines.



Figure 24 Full bore fracture of superduplex stainless steel manifold hub connector

III.2.2 Mechanism

Hydrogen-assisted cracking is generally considered to occur as a result of the combined action of hydrogen and applied or residual stress on a material of susceptible microstructure. However, there are many interrelated factors and variables, and the detail of the cracking mechanism in duplex stainless steels is not completely understood at present. Current understanding of the mechanism and main variables related to hydrogen embrittlement is as follows:

- All duplex stainless steels are susceptible to cracking when polarised to potentials more negative than around -800 mV vs Ag/AgCl/sea water. The threshold stresses for crack initiation reduce as the potential becomes more negative, and at -1100 mV crack initiation occurs at around the 0.2% proof stress, equivalent to about 0.5% strain.
- There is no significant difference between 22% Cr duplex and 25% Cr superduplex stainless steels with respect to crack initiation or propagation.
- The grain size or ferrite unit size has a significant effect on the strain required to propagate cracks. As the grain size decreases the strain for propagation increases.
- Coarse microstructures which have ferrite and austenite aligned parallel to the through-thickness direction are particularly susceptible to cracking because of the continuous ferrite path which is available for propagation.
- Intermetallic phases in the microstructure are generally undesirable, and act to reduce the resistance to crack propagation.
- Duplex stainless steels exhibit 'cold creep' at stresses below the proof stress, and this appears to be significant with regards to hydrogen cracking. The creep leads to reducing stress at a fixed strain level and, for practical purposes, crack propagation will then not normally occur. Under constant load conditions however, creep gives rise to increasing continuous straining, and crack propagation can occur.
- Weld HAZs are critical areas due to the locally reduced resistance to crack propagation and local geometric stress and strain concentration.
- Tensile plastic pre-straining has a beneficial effect in terms of increasing the stress for crack initiation.

The more recent failures of subsea duplex stainless steel hub connectors (Ref: Figure 25) and flowlines have not necessarily been the result of global or full-section yielding of the components, but localised yielding of the material at stress concentrations has clearly been implicated. While existing design codes allow stress concentrations, they do not consider the magnitude of the residual stresses, and they rely on the material being ductile. DNV-RP-F112 was developed as a result of these failures and now embodies good practice for the assessment of stresses and strains in duplex stainless steel subsea components.

The effect of hydrogen is to embrittle the outer surface layers of the material so that there is a reduced tolerance to uncertainties in design stresses, stress concentrations, and residual, fabrication and installation stresses, which can lead to cracking.

The sources of high stresses that led to failures are believed to have included:

- inadequate dimensional control of manifold piping spools, leading to excessively high loads from flange tightening;
- excessive rock dumping of flowlines, resulting in subsidence into the seabed and high bending stresses on manifold connectors; and
- hydrostatic testing and cyclic operation (pressure and temperature) of rigid and flexible flowlines leading to high stresses on end connectors, not adequately assessed during design.

III.2.3 Cathodic Protection Potential

The use of aluminium or zinc anodes will usually produce areas on a subsea structure that are polarised to potentials of -1050 mV or even -1100 mV. This

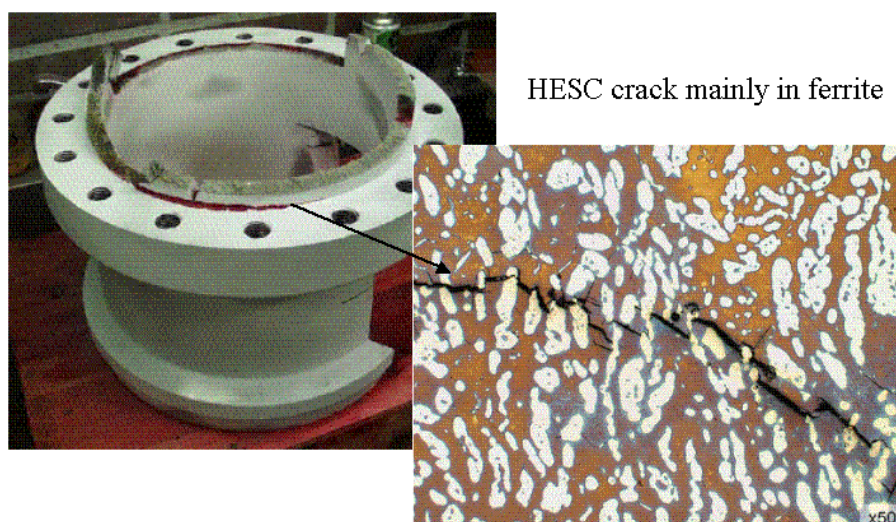


Figure 25 Fractured superduplex hub connector showing the nature of the hydrogen induced stress cracking, mainly in the ferrite matrix.

represents a substantial level of over-protection as far as duplex stainless steels are concerned, and it is clear that at these potentials hydrogen cracking can occur.

Duplex stainless steels can be safely cathodically protected by soft iron anodes or by the use of other low voltage systems (see Chapter 4), though the practicalities of this approach are far from straightforward because of the usual requirements to maintain electrical continuity between subsea components manufactured from dissimilar metals in order to achieve global protection.

III.2.4 Summary and Recommendations

There is a large number of duplex stainless steel systems installed subsea, apparently operating satisfactorily. The principal concern with the subsea application of duplex stainless steels is external hydrogen embrittlement and the associated increased risk of cracking. The following measures are currently believed to represent best practice and will minimise the risk of cracking in subsea service:

- Ensure that all components are supplied in the solution treated and water quenched condition, and have a balanced ferritic–austenitic microstructure free from detrimental tertiary phases such as nitrides and intermetallic compounds. Careful attention to the solution heat treatment temperature–time and to the rapidity of quenching is important. The guidelines in EEMUA 218 are recommended.
- Ensure that all forged components have a principal grain orientation parallel to the longitudinal axis and not in the through thickness direction.
- Use HIPped components where practical. This manufacturing route produces a fine microstructure with no directionality and has greater resistance to hydrogen induced stress cracking
- Apply DNV-RP-F112 for design.
- Ensure that fabrication stresses are minimised, and that pipes are not subjected to cold pull. If necessary, pipe spools should be cut and re-fabricated.

- Ensure that all welds are made to qualified procedures that result in a well-balanced ferritic–austenitic microstructure in the weld zone, typically containing 35–65% ferrite. Autogenous welds should be avoided. Low hydrogen processes are preferred, and shielding gas containing hydrogen should be avoided.
- Ensure that there are no load cases associated with subsea installation, testing, commissioning, operation (including thermal loads), future tie-ins etc., that will generate surface stresses exceeding those experienced during hydrotesting. This will ensure that any benefits from stress shakedown are maintained.
- Use high integrity full life coating systems, particularly at areas of high stress concentration, in order to shield the material from the CP system. Ensure that surfaces are prepared and coated fully in accordance with established industry standards.
- Consider the use of low voltage CP systems: e.g. where practicable, consider electrical isolation of the duplex stainless steel components, and cathodic protection with sacrificial iron anodes or diode controlled sacrificial aluminium or zinc anodes. Although this approach is technically feasible, it is not widely used and there would be concerns about integrity of subsea electrical isolation.
- Avoid fitting zinc or aluminium anodes directly onto duplex stainless steel components as far as possible. For short flowlines this may be achievable by fitting additional remote sacrificial anodes onto steel manifold and platform structures with which the flowline is electrically continuous.
- Use of anode attachment pup-pieces in internally clad carbon steel construction, such that the anode doubler plate is fillet welded onto carbon steel line pipe.

Appendix IV Weldable Martensitic Stainless Steels for Subsea Piping, Flowlines and Associated Components

IV.1 Introduction

Conventional 13% Cr steels have been widely accepted since the 1970s for downhole tubing because of their excellent resistance against CO₂ corrosion, but the high carbon content and the associated high hardenability of these alloys result in poor weldability, which generally precludes wider application. However, steel manufacturers have succeeded in improving the weldability of the 13% Cr steel by modifying the chemistry to reduce the carbon content, leading to the development of alloys generally known as 'weldable 13% Cr steels'.

These weldable martensitic chromium steels have gained increasing interest in the oil industry, and have been employed on a number of projects. This Appendix summarises the current status of the alloys, and identifies a number of issues related to their use in subsea applications.

IV.2 Background

The 13% Cr martensitic stainless steels were originally developed in the early 1900s. Since that time they have undergone two major shifts in terms of composition, in order to improve weldability, toughness and corrosion resistance.

In their original form with carbon levels in excess of 0.10%, i.e. the wrought AISI 410 alloy (0.15% C max) and the casting alloys CA 15 and CA 40 (0.15% and 0.40% C max, respectively), these alloys are air hardening and are considered difficult to weld. A moderately high preheat temperature is required together with PWHT in order to generate sound joints having acceptable mechanical properties. In the 'as welded' condition, these alloys possess very hard martensitic HAZ microstructures, often containing quantities of ferrite. Although the hardness may be reduced by post weld heat treatment, the presence of the ferrite results in inherently low impact toughness. The low-carbon variant of these alloys in centrifugally cast product form has seen limited use for flowlines in sweet, high CO₂ gas fields in Indonesia and Algeria. However, the principal use has been in the seamless hot worked (rolled or forged) and quenched and tempered condition for downhole tubulars and equipment (i.e. normally in the non-welded condition).

In the mid to late 60s, two casting alloys CA 6NM (13Cr/4Ni/0.5Mo) and CA 6N (13Cr/7Ni) with carbon levels of 0.06% max were developed to provide improved weldability and toughness. Whilst notable improvements in these properties were achieved, there is still a requirement for PWHT in order to generate optimum properties. Although the 6NM material has been widely used for applications such as valve and pump bodies, wellheads, and downhole equipment, it has not apparently been used for flowline applications.

Continued pressure for a cost effective, field weldable, CO₂ resistant steel of the 13% Cr type subsequently led to the development of a further generation of martensitic stainless alloys having an average strength level equivalent to X80, and containing 0.03% C max, 11.5–13.5% Cr, 1.0–6.5% Ni, 1.0–3.0% Mo, sometimes with minor Cu additions. These alloys were developed from the recently introduced downhole grades of alloyed 13% Cr steels that have found use in applications requiring higher strength or high temperature corrosion

resistance. They are generally termed 'weldable 13% Cr steels'. The low Ni, low Mo variants within the composition range are intended for sweet service, while those materials with high Ni and Mo have a degree of sour resistance.

IV.3 Availability

The alloy design of the weldable martensitic chromium steels is based around nominally 12% Cr for CO₂ corrosion resistance, with additions of Ni, Mo and in some grades Cu to give improved resistance to SSC. As the Mo content is increased, the Ni level is also increased to minimise the formation of ferrite. The C and N content are kept exceptionally low, providing good weldability and relatively low HAZ hardness in the as-welded condition. The need for PWHT will be dependent on the internal fluid conditions associated with each application. Essentially, three compositional ranges evolved, each capable of providing an X80 strength level:

- 11–13% Cr / 2–3% Ni / < 1% Mo for sweet service (lean alloy)
- 11–13% Cr / 3–5% Ni / 1–2% Mo for mild sour resistance
- 11–13% Cr / 5–7% Ni / > 2% Mo for moderately sour resistance.

Standardisation of these compositions has been slow, and steel makers have developed their own specific elemental ranges. However, it should be noted that the medium and high alloy compositions are now included in BS EN 10088-2 (grades 1.4422 and 1.4423 respectively), and one proprietary steel falling into the highest alloy category has been allotted the designation UNS S41426. Availability of fittings in matching grades is strictly limited.

IV.4 Corrosion Resistance

The proprietary nature of the 13% Cr alloys does mean that their corrosion resistance to production fluids cannot be easily generalised. Alloy suppliers may be able to advise suitability of individual grades, but qualification by corrosion and stress corrosion cracking testing in simulated production environments is strongly recommended. Alloys over the full composition range have been shown to be susceptible to intergranular SCC in sweet environments when tested in the as-welded condition, and a number of onshore field failures have occurred in as-welded girth joints in the leaner alloy compositions. The cracking mechanism is believed to be associated with sensitisation in the HAZ, but the factors controlling crack initiation are not clear. Due to the field failures the lean alloys are not recommended (and are currently no longer available).

The more highly alloyed grades of 13% Cr are generally recommended for subsea applications due to the increased integrity requirements, especially if there is any reasonable probability of reservoir souring in the future. PWHT is recommended as described below.

IV.5 Fabrication

Weldable martensitic stainless steels have been used for a moderate number of projects, and there is now significant practical fabrication experience (refer to Figure 26). Duplex stainless steel consumables are generally used. Porosity has sometimes been a problem when using the 25% Cr consumables, and so 22% Cr consumables have frequently been used in the root, with the higher strength 25% Cr being used for the fill passes.

Differences in absorption characteristics between the duplex stainless steel weld metals and parent materials can lead to some difficulties in radiographic interpretation. The application of ultrasonic techniques can be difficult with dissimilar metal combinations, particularly those involving duplex stainless steel welding consumables. However, AUT techniques have been successfully employed for girth weld examination.

While a variety of welding processes have been demonstrated to be applicable with these alloys, mechanised GMAW has been most widely used for girth welding. In common with other CRA materials, a high integrity, defect free, root pass is desirable, and the GMAW process is not always the optimum welding technique. Consequently, manual GTAW has been employed in a number of cases, particularly for the onshore fabrication of bundled or reeled flowlines.

While the carbon content of these alloys is relatively low, the martensitic HAZ microstructures may possess hardness levels of 350–360 Hv, particularly in the case of the more highly alloyed grades. In applications where this hardness is considered problematic, e.g. for SCC resistance, a PWHT of 650°C for 5 minutes by induction heating has been shown to reduce peak HAZ hardness levels to about 300 Hv. Some care is necessary with PWHT when using duplex stainless steel consumables, particularly 25% Cr superduplex, to ensure that the precipitation of intermetallic phases is minimised.

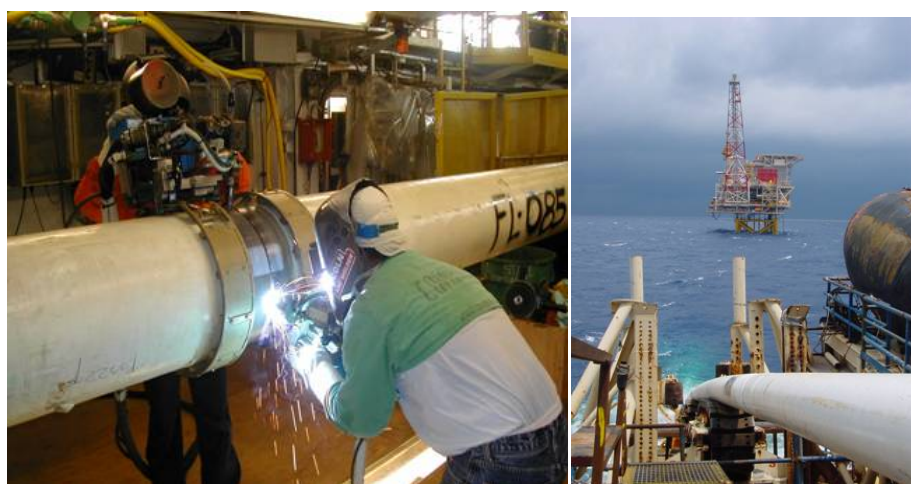


Figure 26 Offshore pipelay of 13% Cr (UNS S 41426) pipeline

IV.6 Interaction with Hydrogen

IV.6.1 Fabrication Hydrogen Cracking

All hardenable ferritic steels are potentially susceptible to weldment hydrogen cracking, and even though the carbon content is particularly low, the weldable 13% Cr alloys retain a level of susceptibility. Limited studies on these alloys have shown the materials to possess a moderate level of resistance to cracking, but nevertheless HAZ hydrogen cracking has been reported when using a combination of GTAW and superduplex consumables. In this case, the weldment was subjected to the relatively high levels of strain (2–3%) associated with pipe reeling operations soon after welding, and the consumables are understood to have contained levels of hydrogen which were possibly slightly higher than normal. Consequently, low hydrogen welding practice should always be followed

when welding these alloys, and this may need to include a degassing heat treatment of the filler wires to minimise hydrogen content. Some operators also recommend the online monitoring of shielding gas humidity.

IV.6.2 Hydrogen Cracking from Cathodic Protection

When used subsea, these alloys will be exposed to hydrogen generated by CP systems except in bundled or pipe-in-pipe designs. Absorption of hydrogen may lead to cracking of susceptible microstructures in the presence of critical stress levels in much the same way as discussed for duplex stainless steels in Appendix III. Several failures of weldable 13% Cr flowlines have occurred in which hydrogen generated by CP systems has been implicated. These failures have led to significant new efforts to understand the problems and modify CP designs. The failures involved external hydrogen cracking at the toe of the fillet welds attaching type 316 stainless steel doubler plates for aluminium alloy bracelet anodes. The fitting of the doubler plates entailed local removal of the factory-applied three-layer coating systems, fillet welding of the plate and attachment strap, and then re-instatement of the coating. PWHT of the fillet welds would not have been practicable. The flowlines were installed by reeling, and it is believed the associated strain cycle led to local disbondment of the doubler plate coating. This allowed seawater to contact the external pipe surface and hydrogen to be absorbed at the fillet weld HAZ. Hydrogen cracking was initiated and through-wall leaks occurred during hydrostatic testing. These flowlines had been held at seabed temperatures, around 4°C, for some time. See Figure 27.

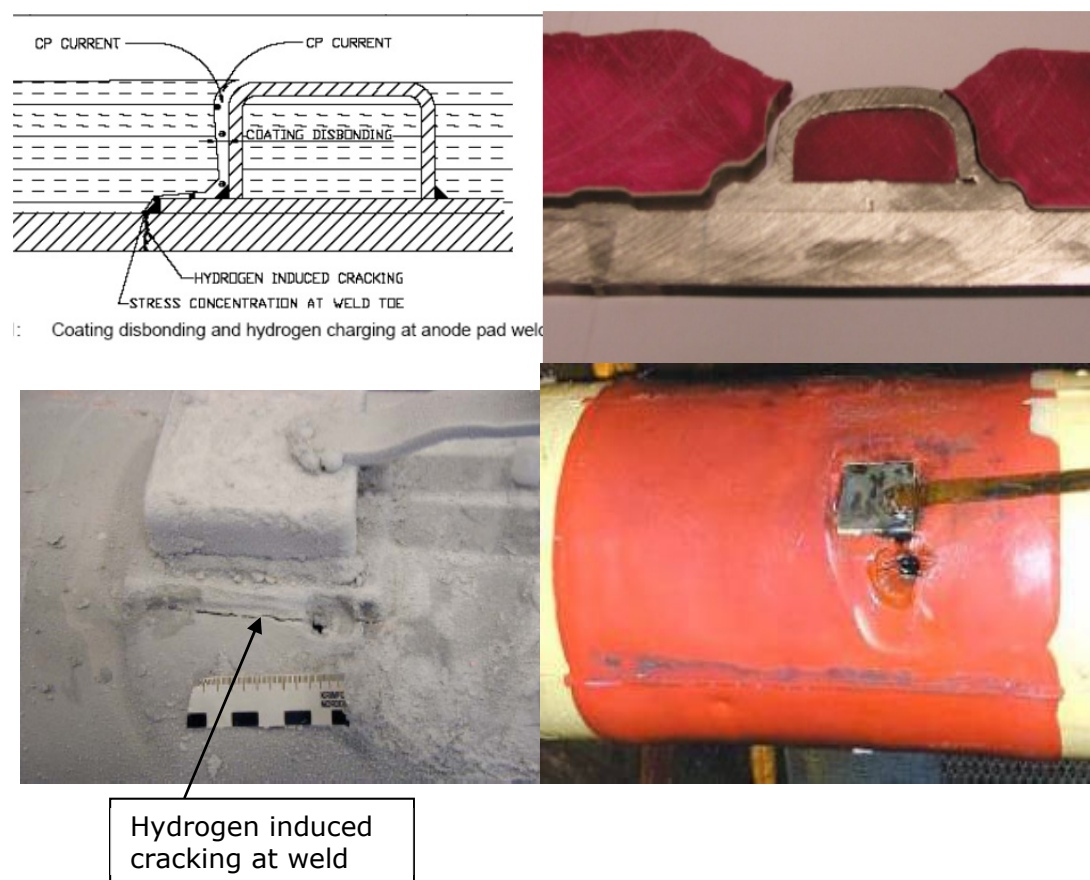


Figure 27 Cracking of 13% Cr pipeline at anode doubler plate attachment weld

Best practices to overcome the problem in design currently include:

- Avoidance of bracelet anodes and doubler plates altogether, relying on CP delivered to the flowlines from remote anodes (no external welding onto the 13% Cr pipe at all). This method is particularly suited to relatively short flowlines equipped with high integrity coating systems.
- Use of anode attachment pup-pieces in internally clad carbon steel construction, such that the anode doubler plate is fillet welded onto carbon steel line pipe.
- Use of low voltage protection systems as discussed in Appendix III for duplex stainless steels, but again, the practicalities of electrical insulation from conventional CP systems may be problematic. One project has used diodes to modify the CP potential to be in the range -600 to -800 mV versus Ag/AgCl reference electrode, and used a relatively thick forged 25% Cr superduplex spool for attaching the electrical continuity flat bar for the anode. This solution necessitated the use of isolating joints at each end of the flow line.

Other less reliable risk-reduction measures for 13% Cr designs incorporating aluminium bracelet anodes include:

- application of doubler plate coatings on the lay vessel after unreeling,
- installation by S-lay instead of reeling, and
- using CP designs to ISO 15589-2 in which anode spacing may be increased, typically from 50–100 m to 900–3000 m.

Risk reduction measures for 13% Cr flow lines already installed and now considered at theoretical risk of cracking at doubler plates include:

- minimisation of in-service stresses arising from free-spanning: inspect and reinstate flow line support as required,
- avoidance of dropped object damage,
- detailed ROV procedures and management of third party vessels to avoid accidental snagging on the flow line and/or anode straps leading to coating damage at the doubler plates, and
- minimisation of production shutdowns (moderately high operating temperatures would be expected to minimise the risk of embrittlement).

Appendix V CRA Clad and Lined Piping for Subsea Applications

V.1 General

The selection of a CRA clad or lined pipe for pipeline and flowlines should follow the general criteria detailed in Chapters 3 and 7. Clearly, the CRA clad layer or CRA liner should be suitable for the service corrosivity, and both the carbon steel and the CRA clad layer or liner should be suitable for the minimum design temperature including, where applicable, that resulting from emergency depressurisation.

For CRA clad or lined pipe it is not usual to take any benefit of the CRA clad layer or liner in determining the design thickness of the pipeline. Benefit of the CRA thickness can only be used if the design is proven by appropriate analysis.

CRA clad or lined pipes are suitable for installation by Controlled Depth Tow Method (bundles), and conventional lay-barge techniques (S-lay or J-lay). Only CRA clad materials have been used to date for reeling but qualification testing programs for lined pipe are currently in progress.

A photo macrograph of a typical butt weld in clad linepipe is shown in Figure 28.

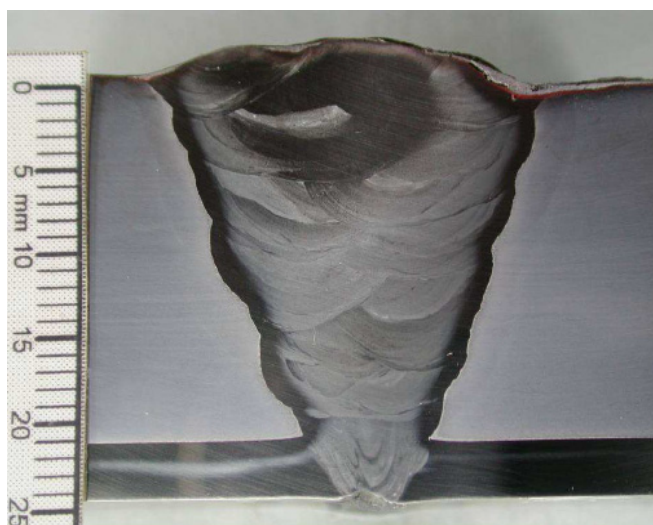


Figure 28 Cross-section of butt weld in 316L SS clad X-65 line pipe made with Alloy 625 consumables

V.2 Pipe

CRA clad or lined pipe is manufactured using either seamless or welded methods in accordance with API Spec. 5LD.

CRA clad pipe is usually manufactured from CRA clad plate in which the CRA is metallurgically bonded to the backing steel by explosive or roll bonding. The clad plate is then formed into pipe and longitudinally seam welded. The clad plate may be manufactured to standards such as ASTM, A264 or A265.

Seamless line pipe may be internally weld deposited overlaid with a CRA weld metal to generate seamless internally clad pipe. Automated GTAW is the most commonly used welding process for deposition of the CRA overlay and a minimum of 2 layers of weld metal (minimum thickness 3 mm) is usually specified. The procedures for weld deposited overlay should be qualified in accordance with ASME Boiler and Pressure Vessel Code Section IX, BS EN ISO 15614-7 or DNV OS F-101.

CRA lined pipe is manufactured by hydraulic or thermo-hydraulic expansion processes in closed dies, which guarantees that the whole of the pipe assembly length for both the carbon steel outer pipe and the CRA liner pipe is expanded simultaneously in a controlled single cycle.

It should be demonstrated through qualification and production testing that the manufacturing process for the CRA lined pipe gives a high integrity reproducible mechanical bond between the base carbon steel outer pipe and the CRA liner.

For CRA lined pipe, the substrate material should be manufactured in accordance with a recognised line pipe standard. API 5L X60 or X65 materials are commonly employed but higher strength grades such as API Spec 5L X80 and/or DNV OS-F101 SMYS 555 may potentially be used subject to satisfactory qualification.

Typical CRA thicknesses are:

- Lined pipe: 2.5–3 mm, dependent on corrosion resistance, possible exposure to raw seawater.
- Clad pipe: 1.5–3 mm, except at welding ends where the minimum recommended thickness is 2.5 mm. The use of thicknesses less than about 2 mm along the pipe lengths may require additional quality assurance.

Where erosion is anticipated refer to Section 3.6.5.4.

For CRA lined pipe, it is desirable to fully solution anneal the CRA liner pipe followed by pickling and passivation prior to the pipe assembly and expansion process to achieve optimum localised corrosion performance.

CRA liner pipes are individually produced and standards such as API 5LC, ASTM API Spec. 5LC, ASTM A312, A358, A790, A928, B673, B705 and B725 may be applicable.

For CRA lined pipe, the surface preparation of the bonding surfaces is important for bond integrity. The substrate should be shot- or grit blasted to an acceptable standard prior to the expansion process. Bonding surfaces should be heated to ensure that both the outside surface of the CRA liner and the inside surface of the carbon steel pipe are dry prior to their assembly, and a specification or drying procedure should exist to avoid subsequent ingress of moisture.

Suitable pipe end preparation by seal welding, by weld overlaying of the pipe ends, or by other equivalent qualified and approved methods, should be an integral part of the manufacturing process.

V.3 Manufacturing Procedure Specification (MPS)

For CRA clad or lined pipe, a detailed MPS should be prepared prior to manufacture, addressing all factors that influence the quality, reliability and integrity of the product.

As a minimum, the MPS should describe the proposed manufacturing processes, steel making processes and chemical composition, pipe and/or plate forming processes, welding procedures and qualifications, heat treatment, NDT, hydrostatic testing, mechanical and corrosion resistance testing, dimensional control, traceability, and marking, packing, shipping and handling, documentation and certification.

V.4 Manufacturing Procedure Qualification Test (MPQT)

For CRA clad or lined pipe, the MPS should be qualified for each pipe diameter and wall thickness, where applicable, by undertaking MPQ testing on pipes in the final manufactured condition. The purchaser, preferably from first day production pipes, should select an agreed number of test pipes.

As a minimum, the MPQ should include all the testing required by the specified reference standards for the manufacture of the CRA clad and lined pipe. The following additional testing should be considered:

i) Bond Strength of CRA Layer or Liner

For CRA clad pipe, the carbon steel-to-CRA-layer bond shear strength should be tested using recognised test methods such as ASTM A 264. The minimum acceptable bond strength, test method and frequency of testing should be by agreement between manufacturer and purchaser.

For CRA lined pipe, the gripping force should be measured to demonstrate the quality, reproducibility and integrity of the mechanical bond. The method of measurement (liner push-out testing or liner expansion testing), test frequency and acceptance criteria should be by agreement between manufacturer and purchaser.

ii) NDE of CRA Layer or Liner

For CRA clad pipe, all seam welds should be subjected to 100% radiography and 100% ultrasonic examination using a system capable of detecting both longitudinal and transverse defects. Ultrasonic examination should also be made at the pipe ends and at intervals along the length for cracks, laminations, inclusions and disbondment.

Weld deposited overlay should be subject to 100% visual and dye penetrant examination (in seamless pipes this should utilise a camera/video recording system to facilitate remote viewing) and the interface between the backing steel and the weld overlay should be examined (100%) for lack of fusion by UT.

For CRA lined pipe, the liner should be subjected, prior to assembly, to 100% eddy current testing of the seam weld and/or radioscopy where applicable. Seal welds and seam welds of the finished, lined MPQT pipes

may be tested using radiographic examination and dye penetrant techniques. Wall thickness evaluation of the CRA clad layer or CRA liner should be made along the length of the MPQT pipes to guarantee uniformity of the CRA clad layer or CRA liner, and ensure conformance with the specified wall thickness requirement.

iii) Corrosion Testing of the CRA Layer or Liner

Corrosion testing (for general and/or localised corrosion and/or SCC) of the CRA layer or liner may be specified. Samples should be taken from finished CRA clad or lined pipes in the final condition, and should include welds as appropriate.

iv) Installation and Operational Strain Simulation

Full-scale strain simulations should be considered to validate the proposed design and installation method for clad or lined pipe. Test programmes should include repeat bend cycles to simulate dynamic installation conditions. The CRA clad layer or liner of the tested pipes should be visually inspected and dye penetrant tested. Girth welds should be examined by radiography or ultrasonics.

v) Coating Simulation for Lined Pipe

A thermal-cycling trial should be considered to simulate the application of external anti-corrosion and insulation coatings where applicable, and demonstrate that the liner will resist thermal expansion buckling.

Clad pipe produced by other processes not listed in API Spec 5LD may have unique features, which would require specific consideration. The respective qualification procedures should however follow the general guidelines outlined above.

V.5 Components Other Than Pipe

Clad fittings, flanges, etc., may form part of the pipeline or flowline system. No international standards exists for these clad components, but the base material and CRA layer should match the respective properties of the CRA clad or lined pipe in the pipeline or flowline system.

Flanges should be forged. Fittings should be forged, wrought single piece or of welded construction. Standards that may apply are:

- Forged flanges—ASTM A 694 and ASME B16.5 or MSS SP-44.
- Forged fittings—ASTM A 694 and ASME B16.9 or B16.28 or MSS SP-75.
- Wrought fittings—ASTM A 860 and ASME B16.9 or B16.28 or MSS SP-75.

CRA clad bends are frequently produced by induction bending clad mother pipe. ISO 15590-1 covers this method of production. Clad mother pipe is usually made by forming and welding CRA clad plate or by weld overlay deposit of CRA on carbon steel base pipe. Standard practice is to supply clad pipes in the as-welded condition, however post-bending heat treatment may be required to obtain the desired mechanical properties in the carbon steel base material and to achieve the optimum corrosion performance of the CRA clad layer.

Consideration should also be given to dimensional changes that occur during bending and in particular to the wall thickness thinning that affects both the carbon steel base material and CRA clad layer.

The CRA weld overlay deposit should not be less than 3 mm thickness in the final supplied condition. The chemical composition of the weld overlay should include a specified maximum iron content which should be measured below the surface at a specified distance above the carbon steel–CRA fusion line.

The procedures for weld deposited overlay should be qualified in accordance with ASME Boiler and Pressure Vessel Code Section IX, BS EN ISO 15614-7 or DNV OS F-101.

Clad components should be qualified in accordance with the methodology detailed for line pipe described above.

For clad induction bends, it is recommended that in addition to the above, a manufacturing procedure qualification test bend is produced for each pipe size and tested at various intervals along the length, including the intrados and extrados, to demonstrate that the properties of the substrate and CRA cladding are maintained.

Appendix VI Recommended Practice for the Automated Welding of Small Diameter CRA Tubing for Control and Chemical Injection

Automated welding procedures for small diameter CRA tubing for hydraulic control and chemical injection duties should initially be qualified in accordance with a relevant standard, e.g. ISO 15614-1 or ASME IX, and the operator should be appropriately qualified. Reference to BS EN 287-1 and ASME IX is recommended for welder qualification. For the purposes of weld procedure qualification, the diameter and wall thickness of test samples to be qualified should ensure that there is sufficient coverage for all tube sizes to be welded. The number of weld samples to be produced should depend upon the number required to provide sufficient material for mechanical and corrosion testing where applicable. After 100% visual, 100% dye penetrant and 100% radiographic examination, the destructive tests should include, as a minimum, tensile, hardness and bend tests. Weld procedure tests on duplex stainless steels also require ferrite count and pitting corrosion testing.

It is also important that the welding parameters are established for each combination of tube diameter and wall thickness at the start of each fabrication contract, even though the essential variables of the weld procedure may be unchanged. This should involve oblique sectioning of each completed weld and performing visual examination, then modifying the welding parameters if necessary, and repeating the process until visually acceptable welds are achieved.

Variations in chemistry (particularly sulphur content) have a significant influence on the operability of the welding equipment. If two different batches of material are joined, the weld arc tends to wander to the low sulphur component resulting in lack of penetration and lack of fusion at the higher sulphur material. It is therefore also important that for each tube size and material grade every combination of material batch undergoes the process of establishing the weld parameters in the same way.

The established parameters should be saved and recorded as part of the qualified weld procedure specification.

In order to adequately demonstrate the reliability, reproducibility and associated skill, it is recommended that each operator should produce a minimum of five joints per tube size, per welding procedure with his allocated welding equipment. Each of these joints should be subjected to 100% visual, 100% dye penetrant and 100% radiographic examination, and should be assessed against the following criteria:

- The weld bead should fully penetrate the joint; no lack of penetration or lack of fusion is acceptable.
- The internal weld bead should exhibit an even bore protrusion. Maximum bore protrusion should be typically 15% of wall thickness.
- The external weld bead should be essentially flat, and exhibit a maximum height of typically 15% of wall thickness.
- Maximum root concavity should typically be 10% of wall thickness.
- Porosity is unacceptable.
- Cracking is unacceptable.

- The minimum weld thickness should be equal to the minimum tube wall thickness.
- The maximum weld thickness should be equal to wall thickness plus 2 mm.

Following the above examination, the welds should be subjected to oblique sectioning at 45–60° in order to expose the internal bead for visual examination, and to metallographic sectioning to confirm compliance with the above criteria. As a minimum, two sections from each weld should be prepared for examination by optical microscope. One of these sections should be taken through the stop/start location.

Fabrication should not be allowed to commence until the tests above have been successfully completed.

During fabrication, all production joints, including welds of pipe to fittings or materials of different lots, should be subjected to 100% visual, 100% dye penetrant and 100% radiographic examination. Joints exhibiting any defect indications should be cut out and re-welded, but only after a further five consecutive visually acceptable welds have been completed to validate the welding procedure.

For high-pressure applications, consideration may be given to performance of burst tests on a short length of manufactured tube containing at least one butt weld Figure 29. The minimum burst pressure achieved should exceed the value calculated using the specified minimum mechanical properties of the material.

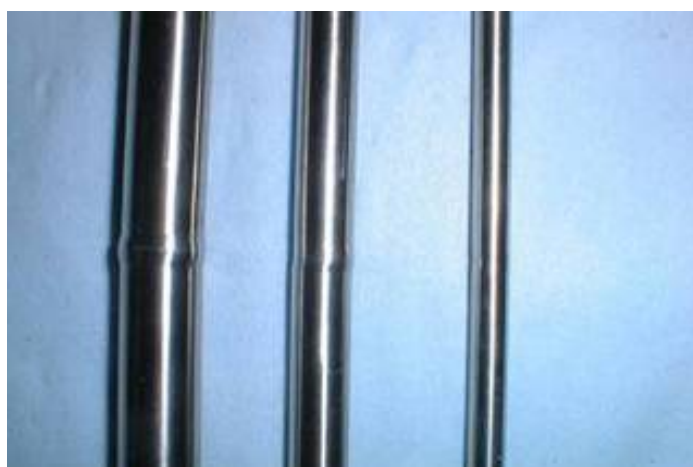


Figure 29 Typical butt welds in hydraulic control tubing made by the automated GTAW process

Appendix VII Automatic Ultrasonic Testing of Pipeline Girth Welds

As stated in Section 7.5.2.1, automatic ultrasonic testing is now the pre-eminent NDT method for pipelines. The advantages of AUT over radiography include:

- **Safety.** The radiation hazard is eliminated.
- **Environmental.** Processing chemicals and waste are eliminated.
- **Administration.** The management of safety systems, licensing and other paperwork is reduced.
- **Logistical.** The movement of radioactive isotopes, especially by air, has become increasingly difficult. No consumables such as film or chemicals are required. Handling of records is easier, and longer archival lives are achieved.
- **Internal Pipe Equipment.** All AUT equipment is external thus no crawlers or stop trolleys are required.
- **Time.** The cycle time is less than that required for radiography.
- **Technical.** AUT generally allows defect height to be sized, whereas radiography presents a two dimensional image. AUT is a more reliable method for detection of planar defects.

Whilst increases in computing power have provided the necessary technology, it is the ability to size defects that has given AUT the additional impetus to largely replace radiography. Engineering criticality assessments (ECAs) and fracture mechanics testing are well developed methodologies, and the ability to size defects allows their application to pipeline welds. The application of ECA based acceptance criteria generally leads to a substantial reduction in repair rate compared with radiography. Repair rates below 1% are common. It has been found that permissible defect sizes do not have to be massively larger than normal workmanship standard sizes to produce a large fall in repair rates. (ECA based weld acceptance criteria have been applied during construction of pipelines using radiography. This is not recommended.)

One area where AUT is particularly beneficial is the inspection of small diameter pipelines. These lines are too small for a conventional crawler to be used and have been inspected by double wall single image techniques often using gamma sources. Apart from the increased safety risk of using radiography outside of the pipe, the time for the multiple shots needed to cover the whole circumference is excessive compared with AUT. Similarly, AUT can be used for inspection of outer pipe welds in pipe-in-pipe systems that would be uninspectable with radiography.

The foremost disadvantage of AUT is the upfront preparation and engineering required. Radiography is an 'off the shelf' solution that is largely independent of the weld procedure, and has well recognised acceptance criteria. AUT is directly linked to the weld procedure since the calibration blocks are designed to mimic the qualified weld bevel and are manufactured from the actual pipe material. The probe arrays are also manufactured to match the weld bevels (but see the paragraph on phased arrays below). The development of the acceptance criteria requires completion prior to the start of inspection, and is dependent upon the weld procedure mechanical test results. Obtaining the consent of the owner and the certifying authorities may require some time. The lead times and costs for these activities can militate against the use of AUT for short lead time projects and small numbers of welds.

AUT is more difficult to apply to CRA welds than radiography. Radiography may be hampered by different absorptions in the dissimilar materials that are found in clad welds, but is otherwise straightforward. AUT is also hindered by changes of material through a weldment and by the large grains typical of CRA weld metals that cause attenuation and scatter of the UT signal. 25% Cr welds can be prone to fine porosity that is mechanically innocuous but causes many reflections that confuse the AUT display. Experience to date suggests that AUT can be applied to carbon steel with a high level of confidence, but that each specific CRA application requires being specifically trialled and qualified as early as possible in a project.

The need for trials of an AUT system prior to construction will depend on several factors including the AUT contractor's track record, previous application to the welding system, the material, the joint configuration and the prior knowledge of the pipeline owner and the certifying authorities. A full qualification programme is described in DNV OS-F101. A common method for gaining confidence in an AUT system (for a specific project) is to make extra welds during weld procedure qualification that contain realistic, deliberate defects for radiography and sectioning.

A distinction can be made between AUT contractors who manufacture their own equipment and those who purchase it. In both cases, AUT equipment has proved to be reliable even under arduous lay-barge conditions. AUT systems may be based on the use of combined pulse echo and time of flight diffraction (TOFD) techniques. TOFD is particularly useful for irregular defects not aligned with the weld bevel. Systems employing phased array probes are now becoming more common. The significant advantage of phased array probes is their flexibility, which not only reduces the size of the probe arrays but also allows pipe sources with different velocities, thicknesses and bevel preparations to be catered for without changing equipment.

When undertaking AUT scanning, the alignment of the probe array with the original weld bevel is important, especially with systems placing a high reliance on tightly focused beam sizes. Consideration should also be given to the temperature at which scanning actually occurs compared with the temperatures used for calibration or pre-construction trials. Calibrations are a necessary feature of ultrasonic testing and could be undertaken prior to each weld, but this has been found to be impractical and unnecessary during high productivity pipelay. For the inspection of SAW welded pipe, it is necessary to remove the long seam for a distance of around 75 mm to 150 mm depending upon thickness and the probe angles. Ideally this should be done in the pipe mill.

Appendix E of DNV OS-F101 provides criteria and guidance for AUT of girth welds. ASTM E 1961 also gives criteria for undertaking AUT. In addition to OS-F101, the pipeline welding standards BS 4515, API 1104 and CSA Z662 all permit the use of ECA-based acceptance criteria. The latter two standards contain appendices concerning the production of ECA criteria. BS 7910 is a standard concerned with general weld flaw acceptance criteria rather than specifically for pipelines, but is frequently used to develop pipeline acceptance criteria.

The term 'automatic' in the term AUT is slightly misleading since manual involvement is crucial to its operation, particularly in regard to interpretation. Whilst it is common for the pulse-echo channels to use colour to flag responses above the reference level, it is necessary to have qualified and experienced personnel to sentence the welds. The operator needs to assess all the

information available, which may include pulse-echo, TOFD and mapping channels. For instance, a response above the reference level may be due to high-low in the root rather than a defect. Personnel performing interpretation need to have a thorough knowledge of their AUT system and have an understanding of the welding process being used. It is recommended that the interpreter has a Level II ultrasonic qualification in accordance with BS EN 473, and ideally, CSWIP certification in Automated Ultrasonic Testing (AUT) Data Interpretation. Operators should have successfully completed the AUT contractor's in-house training course (typically two weeks) and have undergone a period of supervised interpretation in the field prior to assuming responsibility for weld interpretation. Operators and interpreters should demonstrate the satisfactory application of the relevant procedures prior to start up and it is recommended that interpreters should further demonstrate correct interpretation of say, ten previously collected AUT screen records.

It is common for AUT contractors to provide short courses (typically two days) for inspectors and engineers to increase understanding of the system and to enable review and discussion of results during inspection. Training providers are now seeking to introduce schemes for certification of AUT interpreters that will provide a basis for second- and third-party interpretation. These schemes tend to be equipment type specific.

Appendix VIII Abbreviations

AISI	American Iron & Steel Institute
AMS	Aerospace Material Specifications
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
AUT	Automatic ultrasonic testing
BS(I)	British Standard(s Institution)
CP	Cathodic protection
CRA	Corrosion resistant alloy
CSA	Canadian Standards Association
CTOD	Crack tip opening displacement
DN	Numerical designation of size of piping components which approximates to the nominal diameter, in mm, of the corresponding line pipe
DNV	Det Norske Veritas
ECA	Engineering criticality assessment
EEMUA	Engineering Equipment and Materials Users' Association
EFC	European Federation of Corrosion
ELI	Extra low interstitial
EN	(European Standard)
ENP	Electroless nickel plating
EPDM	Ethylene propylene diene monomer
ERW	Electric resistance welded
FBE	Fusion bonded epoxy
FCAW	Flux cored arc welding
FFPM	ASTM designation for perfluoroelastomers
FJC	Field joint coating
FPM	ASTM designation for fluoroelastomers
FPSO	Floating production, storage and offloading (vessel)
GMAW	Gas metal arc welding
GTAW	Gas tungsten arc welding
HAZ	Heat affected zone
HB	Brinell hardness
HDPE	High density polyethylene
HE	Hydrogen embrittlement
HIC	Hydrogen induced cracking
HIP	Hot isostatic pressing(s)/pressed
HNBR	Hydrogenated NBR
HRC	Rockwell hardness 'C'
Hv	Vickers hardness
HVOF	High velocity oxy-fuel
IIW	International Institute of Welding
ISO	International Organization for Standardization
LME	Liquid metal embrittlement
MDPE	Medium density polyethylene
MPQ(T)	Manufacturing procedure qualification (test)
MPS	Manufacturing procedure specification
MSS	Manufacturers' Standardization Society of the Valve & Fittings Industry
NACE	National Association of Corrosion Engineers
NACE MR	NACE Material Requirement

NACE TM	NACE Test Method
NBR	Nitrile-butadiene rubber
NDT	Non destructive testing
NORSOK	Norsk Søkkel Konkuranseposisjon ('the competitive standing of the Norwegian offshore sector')
NPS	Nominal pipe size
NPT	[US] National pipe thread
P&NGI	Petroleum and Natural Gas Industries [includes petrochemical]
PD	(BSI) published document
PE	Polyethylene
PEEK	Polyether ether ketone
PEX	ASTM designation for cross-linked polyethylene (see also XLPE)
PiP	Pipe-in-pipe
PIR	Polyisocyanurate
PLEM	Pipeline end manifold
PLET	Pipeline end termination
PP	Polypropylene
PPS	Polyphenylene sulphide
PR	Performance requirement (level)
PREN/PREw	Pitting resistance equivalent number
PSL	Product specification level
PTFE	Polytetrafluoroethylene
PU	Publication
PUF	Polyurethane foam
PVC	Polyvinyl chloride
PVDF	Polyvinylidene fluoride
PWC	Preferential weld corrosion
PWHT	Post-weld heat treatment
QA/QC	Quality assurance/control
ROT	Remotely operated tools
ROV	Remotely operated vehicle
RP	Recommended Practice
RTJ	Ring type joint
SAW	Submerged arc welding
SCC	Stress corrosion cracking
SCR	Steel catenary riser
SMAW	Shielded metal arc welding
SMYS	Specified minimum yield stress
SOHIC	Stress oriented HIC
Spec	Specification
SRB	Sulphate reducing bacteria
SS	Stainless steel
SSC	Sulphide stress cracking
Std	Standard
SUT	Society for Underwater Technology
SWC	Step-wise cracking
TFE/P	Tetrafluoro-ethylene/-propylene
TIG	Tungsten inert gas (welding)
TOFD	Time of flight diffraction
TS	Tensile strength
TSA	Thermally sprayed aluminium
UNS	Unified Numbering System (see <i>ASTM E527</i>)
UTS	Ultimate tensile strength
UV	Ultra-violet (radiation)

YS	Yield strength
XLPE	Cross-linked polyethylene (see also PEX)

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