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**November 2007**

**International Experiences with Cathodic  
Protection of Offshore Pipelines and Flowlines**

**For: Petroleum Safety Authority Norway**

# International Experiences with Cathodic Protection of Offshore Pipelines and Flowlines

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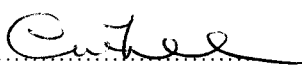
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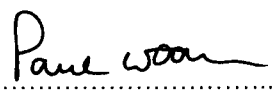
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This report has been reviewed in accordance with TWI policy.

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# 1 Introduction

The majority of materials currently used for the construction of subsea pipelines and flowlines will corrode if they are not protected from the corrosive seawater environment. The mitigation of corrosion in these systems almost always relies on a protective coating and an effective cathodic protection (CP) system. This is usually achieved by adhering to different approved international standards and internal company guidelines. This approach is therefore reliant on the quality of guidance of the approved international standards and the interpretation of this information in designing and implementation of the coating and cathodic protection systems.

Recently a number of changes have been made in cathodic protection standards which have been attributed to enhancements in the knowledge of degradation mechanisms (e.g. learning from failures of new pipeline and flowline materials), from advances in technology (e.g. high integrity insulated coatings and potential controlled CP systems) and oil and gas development in more severe (e.g. deeper water) environments. By implication, as standards and guidelines evolve and change with new knowledge, coating and cathodic protection systems can also change. This results in protection systems (both coating and cathodic protection) designed and installed a number of years ago which can differ from guidance offered in current standards and also new designs will be introduced in accordance to changes in the same standards.

This report is prepared to support PSA supervisory activity, highlighting the status, experiences and trends of ageing and new cathodic protection and coating systems for offshore transport pipelines and flowlines worldwide. In support of this work, a questionnaire was also sent to a number of oil and gas operators and engineering companies which have direct involvement in the design, and installation of cathodic protection systems. Data from this is also presented in this report.

## 2 International Guidelines

### 2.1 Chronology

There have been a number of guidelines and standards produced in respect of offshore cathodic protection (CP). The most important of these in the context of this study have been (in order of first origination):

**Table 1** CP standards

Source	Ref	Title	First issue	Revised
NACE	RP0169	Control of external corrosion on underground or submerged metallic piping systems	1969	1992, 1996, 2002 (replaced by ISO, 2004)
	RP0675	Control of external corrosion on offshore steel pipelines	1975	1988 (withdrawn 1998)
BS <sup>1</sup>	CP1021	Code of practice for cathodic protection	1973	Superseded by ENs
	EN12474	Cathodic protection of submarine pipelines	2001	
DNV <sup>2</sup>	TNA703	Cathodic protection evaluation	1981	Superseded
	RPB401	Cathodic protection design	1986	1993, 2005
	RPF103	Cathodic protection of submarine pipelines by galvanic anodes	2003	
NORSOK	M503	Cathodic protection	1994	1997, 2006 (draft)
EEMUA <sup>3</sup>	194	Guidelines for materials selection and corrosion control for subsea oil and gas production equipment	1999	2004
ISO <sup>4</sup>	15589-2	Cathodic protection of pipeline transportation systems – part 2: offshore pipelines	2004	

In addition, a number of operators have their own in-house, standards (e.g. Shell – DEP: BP – ETP). While largely based on one or other of the international documents, they often use alternative design parameters based on their own operating experience.

### 2.2 Development

The standards applicable to offshore lines have been subject to a process of evolution, largely due to:

- increasing availability of data from existing CP systems
- the need to move into more challenging environments (deeper waters)
- a requirement for more corrosion resistant materials to cope with more aggressive internal fluids.

The development of the standards listed in section 2.1 is described in the following sections.

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<sup>1</sup> British Standard  
<sup>2</sup> Det Norske Veritas  
<sup>3</sup> Engineering Equipment and Materials Users Association  
<sup>4</sup> International Standards Organisation

### 2.2.1 NACE

The NACE recommended practice RP0169 covered both onshore and offshore pipelines with a marked bias to the former. As a result, its usefulness in respect of offshore installations was severely circumscribed. RP0675 was introduced in 1975, but retained many of the shortcomings of its predecessor. In particular, with the exception of the protection potential, no advice was offered in respect of design parameters. Even the advice on potential was flawed, referencing potentials to the copper | copper sulphate reference used onshore, rather than the silver | silver chloride | seawater reference appropriate for use in seawater. RP0675 was withdrawn in 1998.

Following that withdrawal, a NACE task group<sup>5</sup> was set up to rewrite, in its entirety, the offshore pipeline standard. In 2003, that group recommended that, in light of the development of a new ISO standard (see below), which had international recognition, NACE should discontinue its own standard. The rationale behind this decision was published in a paper<sup>6</sup> presented at the 2004 NACE corrosion conference. This paper included some useful comparisons between the design parameters used in the various standards and is returned to later in this review.

The task group identified two perceived shortcomings in the ISO standard. These related to the use of electrical isolation, and to coatings. While acknowledging that an ISO standard for the latter was proposed, it recommended that NACE prepare state-of-the-art reports on both topics. As reported in a 2006 NACE paper<sup>7</sup>, this has resulted in the preparation of a technical report<sup>8</sup> covering both issues, and proposals for some modifications to the ISO standard to be recommended for incorporation in an anticipated revision of the latter, due in 2009.

### 2.2.2 British Standards

The earliest European advice on CP was provided in Code of Practice CP1021, published in 1973. This covered all conditions in which CP could be applied, and included onshore and offshore installations, ports and harbours, tanks and shipping. It provided a brief (one page) section on offshore pipelines, but was short on advice in respect of design parameters, again with the exception of protection potential.

From 2000 onwards, the preparation of a number of Euronorm standards (designated BS EN), each covering one of the specific areas covered by CP1021, superseded the original Code. These included general advice on CP in seawater<sup>9</sup>, and advice specific to offshore pipelines in EN 12474. Unlike CP1021, the latter provided a number of design parameters, notably protection current densities and the concept of coating breakdown. Following the lead set by DNV, current densities were proposed according to the pipeline location, but with no specific recommendations in respect of depth, other than the statement that '*The values .... should be adjusted, if necessary, to take into consideration the variation of the oxygen content in seawater with the depth.*' Values for buried lines were introduced. Recommendations for protection potential levels acknowledged the possibility of hydrogen embrittlement in some materials.

Despite being still current, BS EN 12474 has effectively been replaced by the ISO standard.

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<sup>5</sup> STG-30-TG169

<sup>6</sup> I J Rippon, 'New ISO cathodic protection standard for offshore pipelines', Paper 04101, Conf. Corrosion2004, NACE, Houston, USA

<sup>7</sup> I J Rippon, 'A new standard and state of the art report from TG169 cathodic protection in seawater', Paper 06101, Conf. Corrosion 2006, NACE, Houston, USA

<sup>8</sup> NACE TG169 Technical Committee Report, 'Electrical isolation/continuity and coating issues for offshore pipeline cathodic protection systems' publ. NACE, Houston, USA (2005)

<sup>9</sup> BS EN 12474:2000, 'General principles of cathodic protection in seawater'

### 2.2.3 Det Norske Veritas RP B401

Introduced in 1981 as a Technical Note intended as an aid to the evaluation of offshore CP designs, the recommended practice RP B401 became, in 1986, the first definitive guide to the design of CP systems for offshore structures and pipelines. The subsequent development of the standard has been the subject of a recent paper<sup>10</sup> which provided a detailed description of the key drivers for the changes introduced. A summary of these is provided here.

The 1986 revision, although not describing calculation procedures, did provide the following, previously not covered by the then existing standards:

- Design current densities for a (limited) number of geographical areas
- Typical anode performance parameters and recommendations in respect of quality
- Recommendations concerning the effects of coatings
- Minimum design current densities for coated pipelines sufficient for up to 30 years.

The RP was extensively revised in 1993 to provide detailed calculation procedures for sacrificial anode CP systems. It also laid down requirements for the proper documentation of CP designs. In respect of design parameters, the following changes were made:

- The geographical coverage of recommended design current densities was extended by reference to four different climatic regions (arctic, temperate, sub-tropical, tropical) identified by ambient temperatures.
- The definition of two depth zones for the allocation of current, with current densities for depths < 30 m 10% to 20% higher than those at greater depths.
- Proper definition of coating breakdown parameters, with a linear relation between breakdown and life.
- Assignment of different coating breakdowns to four categories of coating defined with respect to their formulation and overall film thickness.
- Specific reference was made to the possibility of hydrogen embrittlement of high strength steels and some corrosion resistant alloys, and the resultant need to control potentials.
- Specifically for pipelines, the RP referred, in addition the older asphalt/concrete, to newer coatings such as fusion bonded epoxy (FBE) in combination with polyethylene (PE) or polypropylene (PP), and to polychloroprene rubbers (e.g. neoprene). In the absence of in-service experience for the newer coatings, breakdowns identical to those recommended for asphalt/concrete were applied to all these coatings.

Crucially, the RP emphasised that the guidelines used were deliberately selected to be conservative, and were *'...likely to provide an actual life which exceeds the design life of the system in most cases.'* As a result *'Operators' own experience or other special considerations may justify the application of less, or, in certain case, more conservative design data.'* The NORSOK standard (see below) was produced to apply just such a set of criteria based on Norwegian experience

<sup>10</sup>

T Sydberger, K Lønvik, M J Doherty and J Skinner, 'New DNV recommended practices for galvanic anode marine cathodic protection', Paper 06102, Conf. Corrosion 2006, NACE, Houston, USA



- The latest revision (2005), as well as updating a number of design parameters, the most significant of which provided current densities for much greater water depths, and variation of coating breakdown with depth, made a number of deletions, notably:
- Guidelines related to impressed current systems
- Guidelines related to CP inspection and monitoring
- CP design, anode manufacture and anode installation guidelines for subsea pipelines.

As a result RP B401 no longer has direct relevance to the subject of this review. In this context, it has been replaced by RP F103.

### **RP F103**

The development of the new DNV pipeline standard was prompted by significant changes in the design of submarine lines from the early 1990s. Before that time, lines were generally large diameter trunk lines, with a coating of asphalt, or latterly, FBE, with a concrete weight coat for mechanical protection and/or anti-buoyancy. Damage, at least to the weight coat, was common, and this was reflected in the coating breakdowns used in RP B401 (up to 2005) and the early versions of the NORSOK standard. The relatively high currents required that bracelet anodes be fitted at regular intervals, usually not exceeding 200 m, along the lines.

More recently, offshore oil and gas fields have been commonly developed using subsea wellheads and manifolds linked to platforms or floating structures by smaller diameter flowlines and risers. These are often in much deeper waters and laid by reel barge. Much improved coatings have been developed to counter both the installation and in-service conditions. These coatings include 3-layer polypropylene and insulating coatings, which are of considerably higher integrity than the earlier coatings. Installation of bracelets, particularly on insulated lines, represents a weak point, due to the need to penetrate the coating for connection of the anode.

Further, a number of failures had been experienced at anode attachment doubler plates on 13%Cr martensitic stainless steel pipelines. This was diagnosed as hydrogen induced stress cracking (HISC) caused by excessively negative CP protection potentials combined with high stress. This was another reason for avoiding direct anode attachment to the line.

RP F103 was introduced to exploit the much better performance of modern coating systems thus enabling a reduction in the number and frequency of anode attachments on a pipeline. For short lines, the intention of F103 was that protection should be provided by (usually) stand-off anodes on adjacent structures, rather than conventional bracelets. Such anodes would be cheaper, more amenable to inspection and retrofit and, because they could be mounted well above the mudline, more predictable in operation. The new RP provided equations for the calculation of potential attenuation along the lines to ensure protection 'at-a-distance'.

In contrast to all the earlier recommendations, the intent of the new standard was to '*...remove any undefined conservatism from the CP design assumptions.*'. This inevitably puts a premium on the correct execution of other aspects of the corrosion control design. Unless

- CP designs on adjacent structures are correctly executed (thus avoiding adverse current drain on the line)

- mechanical damage to the line during installation and operation (unexpectedly increasing CP current demand) is avoided

and, importantly,

- coating specification and application, especially for field joints, are of the highest quality (preventing higher than expected coating deterioration),

the installed CP provision will not last for the required lifetime of the pipeline. Designs to earlier standards always had some leeway in this regard.

It may be noted that at the time F103 was being prepared, early drafts of the new ISO standard (see below) were being circulated to interested parties, and had considerable commonality of approach to that described above. As a result F103, rather than being fully self-contained, makes reference to ISO in a number of key areas, mostly in respect of general guidelines and anode specification.

#### **2.2.4 NORSOK**

In 1994, taking advantage of the DNV dispensation allowing the use of experience- based parameters, a group of Norwegian operators produced NORSOK standard M503. This largely adopted the DNV approach, but amended many of the CP design parameters, particularly those related to the Norwegian sector of the North Sea. It also differed in respect of the coating breakdowns used, for which it provided tabulated values, rather than those based on linear breakdown over life used by DNV. In respect of pipelines the first version of M503 suggested lower coating breakdowns than the then extant version of B401, but this mismatch was corrected in the 1997 revision.

Edition 3 of M503, represents a major revision of the standard. In respect of design procedures in general, and subsea structures in particular, it largely follows the latest revision of DNV RP B401. However, the section covering CP for pipelines generally accords with ISO 15589-2, which is referenced in respect of potential criteria, current demand and anode spacing. It does however, introduce additional conservatism by mandating a doubling of current demand close to subsea installations (to compensate for possible unintended current drains) and increasing the current demand by a factor of 1.5 for '*critical and strategic*' pipelines.

#### **2.2.5 EEMUA**

EEMUA Publication 194 does not provide any detailed advice on CP, but is a useful background information source covering all aspects of the engineering of subsea installations. Notably, it recommends the application of ISO 15589-2 to submarine pipelines and flowlines.

#### **2.2.6 International Standards Organisation**

As will be clear from the foregoing, ISO 15589-2 has found general acceptance and has superseded the NACE and BS pipeline documents. It is also referenced extensively in DNV RP F103 and the pipeline section of NORSOK M503 (Ed. 3). There are, however, some key differences between them, in respect of current density and coating breakdown, particularly in respect of field joints. Details of the historical development and current status of the design parameters recommended in the individual standards are discussed in section 3 of this review.

## **3 CP Design Parameters For Pipelines<sup>11</sup>**

### **3.1 Design life**

Although not strictly a parameter covered by the codes, it is worth noting that, for all codes up to 2003, in-built conservatism in the design assumptions led, if correctly applied, to CP systems which could be expected to comfortably exceed their design life unless major disruption to coatings occurred. Although still implicit in the ISO 15889-2 standard, and deliberately built-in to NORSOK M503, such conservatism has been explicitly removed from DNV RP F103. For systems designed to the recommendations of the latter, design lives will only be achieved if adjacent CP systems, and pipeline and field joint coatings, are designed and produced to the highest possible standards.

### **3.2 Environmental conditions**

It is a well known fact that one of the key factors in designing viable CP systems is the nature of the environment and in particular the oxygen content, which in turn is related to the temperature. Also of importance are the local flow rates and the water depth, the latter having a significant influence of the formation of calcareous deposits. A combination of these factors dictates the current densities required to ensure protection.

Unlike the equivalent covering offshore structures (RP0176), the NACE pipeline standard offers no advice on the environmental conditions in which it is to be applied. Similarly, BS CP1021 did not consider any variability in the environment, but this omission was corrected in BS EN 12474, which grouped the protection current densities required into four separate geographical categories, identified as specific locations (e.g. North Sea, Arabian Gulf etc.), but made no reference to the effect of depth.

DNV in the original RP B401, adopted a similar geographical area approach to BS but in the first revision reverted to defining four climatic regions, namely arctic, temperate, sub-tropical and tropical, each with its own temperature band. Depth was divided into (only) two zones, above and below 30 m, to allow for tidal and splash effects. The effect of depth was only introduced into the 2005 revision, when four depth ranges were incorporated while retaining the four climatic regions. By contrast the DNV pipeline RP F103 makes no specific reference to geographic area or water depth.

NORSOK standards are confined to the conditions found in the North and Norwegian Seas and, therefore, have limited applicability in a global context. In respect of depth considerations, they use the same four depth ranges as the most recent version of RP B401.

ISO 15589-2 makes no blanket reference to geographical areas, instead providing graphical data in respect of the effect of temperature on design current densities. It does, however, acknowledge that exceptions will occur in some areas with variations in oxygen content with depth, significant seabed currents or high water depths. In this regard it provides specific data for the US West Coast, Cook Inlet, Australia and the Norwegian Sea.

### **3.3 Protection potential**

The single criterion defining the successful application of CP is the protection potential achieved. From the earliest standards, the target potential<sup>12</sup> for carbon steel in seawater has been, and remains, –800 mV or more negative. This is the only value given by NACE, but all the other sources also mention the need for a more negative potential (-900 mV) in anaerobic conditions. DNV, in RP B401:1993, point out that systems correctly designed to these criteria rapidly stabilise at significantly more negative potentials (-900 to –1000 mV), which they describe as optimum.

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<sup>11</sup> In this section, if not stated, all standard refers to the latest edition.

<sup>12</sup> All potentials in this document are stated relative to the silver | silver chloride | seawater reference

Later versions of some standards (but not NACE RP0169 or NORSOK M503) acknowledge the effect of excessively negative potentials in promoting HISC in susceptible materials such as high strength, and duplex and martensitic stainless, steels. Appropriate testing of such steels is recommended before applying CP, and the importance of controlling both metallurgical condition and stress levels is emphasised. DNV RP B401:2005 refers to the need to consider potential control for these materials, using diodes or low driving potential anodes. Only ISO 15589-2 (and by reference, DNV RP F103) suggest that potentials more negative than a given value (-800 mV) should be avoided if HISC is a possibility. The subject of HISC is considered in detail in section 6 of this review.

Present recommendations for protection potentials for pipelines are, therefore, those contained in Table 1 of ISO 15589-2:2004, as referenced in DNV RP F103:2003 and the Revision 3 of NORSOK M503:

**Table 2** Recommended protection potentials from ISO 15589-2:2004 Standard

Pipeline material	Environment	Least -ve potential (mV)	Most -ve potential (mV)
Carbon steel:			
SMYS <sup>13</sup> < 550 MPa	Aerobic	-800	-1100
	Anaerobic	-900	-1100
SMYS > 550 MPa	All	Must be determined by HISC testing	
Stainless steels:			
Austenitic:			
N <sub>PRE</sub> ≥ 40	All	-300	-1100
N <sub>PRE</sub> < 40	All	-500	-1100
Duplex	All	-500	If HISC possible: -800
Martensitic (13Cr)	All	-500	If HISC possible: -800

None of the standards indicate any variability of protection potential with water depth, salinity or temperature.

### 3.4 Design current densities

A key factor in designing viable CP systems is the nature of the environment and in particular the oxygen content, which in turn is related to the temperature. Also of importance are the local flow rates and the water depth, the latter having a significant influence of the formation of calcareous deposits. A combination of these factors dictates the current densities required to ensure protection.

Until 2003, current densities required for protection of any exposed steel on pipelines were assumed to be identical to those required on structures. For each CP design, three current densities were invoked:

- Initial: a high value to allow for first polarisation
- Mean<sup>14</sup>: the average required through the life
- Final: a reserve of available current to ensure re-polarisation.

The values quoted varied with each revision, as operating experience accumulated, with, in general, recommended mean current densities falling with time and polarisation (and re-polarisation) values increasing. By 1993, values for each of the four geographical areas reflected the effect of increasing temperature in reducing the solubility of oxygen and hence reducing the current requirement. Prompted by the trend to developments in ever-deeper waters, the most recent revisions reflect the fact that below about 300 m the formation of calcareous deposits is hindered and, as a consequence, current demands are higher.

<sup>13</sup> Specified minimum yield stress

<sup>14</sup> Sometimes referred to as the maintenance current density

Thus, the latest revision (2005) of RP B401 gives the following current requirements for structural bare steel:

**Table 3** Recommended current densities for CP design as a function of depth and 'climate region' from DNV RP B401.

Area	Temp (°C)	Depth (m)	Current density (mA/m <sup>2</sup> )		
			Initial	Mean	Final
Tropical	> 20	0 - 30	150	70	100
		>30 - 100	120	60	80
		>100 - 300	140	70	90
		>300	180	90	130
Sub-tropical	12 - 20	0 - 30	170	80	110
		>30 - 100	140	70	90
		>100 - 300	160	80	110
		>300	200	100	150
Temperate	7 - 11	0 - 30	200	100	130
		>30 - 100	170	80	110
		>100 - 300	190	90	140
		>300	220	110	170
Arctic	< 7	0 - 30	250	120	170
		>30 - 100	200	100	130
		>100 - 300	220	110	170
		>300	220	110	170

The NORSOK M503 (Ed 3) standard, which confines itself to providing values for Norwegian waters, uses identical values to DNV RP B401, with the North Sea up to 62°N being considered 'temperate' and Norwegian waters above 62°N being 'Arctic'.

These current density values are those applicable to ambient temperature open seawater. For buried parts of structures, and pipelines, where oxygen access is restricted, a constant value of 20 mA/m<sup>2</sup> is assumed.

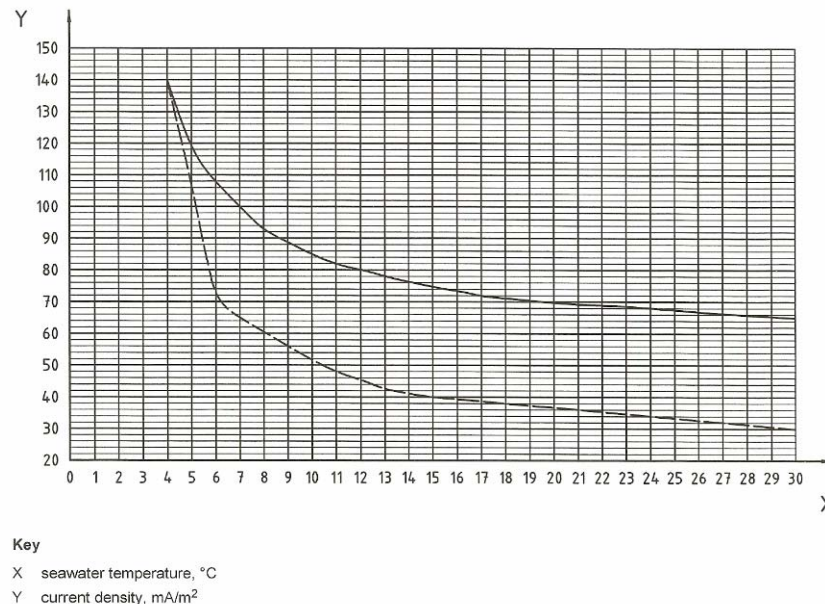
For pipelines, or other surfaces at elevated temperature, the ISO 15589-2 standards specify that the design current density be increased by 1 mA/m<sup>2</sup> for every degree centigrade that the "metal/environment" exceed 50°C. DNV F103 tabulate design current density values for pipelines operating in 4 temperature ranges: <50°C, >50-80°C, >80-120°C and >120°C, in non-buried and buried states.

In contrast to structures (manifolds wellhead etc), CP designs for pipelines, which are invariably coated, are not constrained by the requirement to set initial current densities sufficient to produce protective calcareous deposits. The initial current density becomes irrelevant. Further, for equipment at depth conditions are not believed to be such as to require a depolarisation provision since depolarisation requires tidal and storm effects to exist. Thus, the only current density required for pipeline CP design becomes the mean (maintenance) value.

This is the approach followed by both of the pipeline-specific standards (ISO and F103). However, in respect of current density recommendations, these two documents follow totally different approaches. Accordingly, these are discussed separately here.

### 3.4.1 ISO 15589-2: 2004

As discussed, ISO 15589-2 uses a single value for current density throughout life. Rather than values for specific geographic areas, it provides advice in the form of a graph, reproduced below, relating current density to ambient environment temperature, which



indicates a maximum current density around 140 mA/m<sup>2</sup> at 3-4°C.

**Figure 1** Recommended current densities for CP design from ISO 15589-2:2004.

Above this temperature, two graphs are provided, the upper being based on earlier EN and NACE data, and the lower on practical data from Shell<sup>15</sup>. ISO provide the following guidance in respect of the use of these curves:

- *The lower current density curve may be used where there are no significant changes in oxygen content from surface to seabed, no problems building up calcareous films, and low to moderate seabed currents (up to 2 knots).*
- *The upper curve represents the highest current density values reported, which are required where oxygen content, calcareous films and seabed currents have to be considered.*

They further state that 'If no other data are known, the upper curve (in the figure) should be used' but also that 'Current densities can alternatively be based on field measurements of data from facilities installed in the same geographical location'.

The above recommendations are stated to apply to depths down to 500 m. The standard is less than precise for greater depths, referring to the following specific conditions:

<sup>15</sup> I J Rippon, 'New ISO cathodic protection standard for offshore pipelines', Paper 04101, Conf. Corrosion2004, NACE, Houston, USA

**Table 4** Recommended current densities for CP design for extreme conditions from ISO 15589-2:2004

Location	Depth (m)	Temperature (°C)	Current density (mA/m <sup>2</sup> )	Comments
Cook Inlet	'all'	2	380	High seabed currents
Norwegian Sea	< 1500	-1 to 4	300	Cold deep conditions

All values are to be increased by 1 mA/m<sup>2</sup> for every degree centigrade above 50°C, this being referenced to the outside surface temperature of the pipe. ISO 15589-2 also make it clear that these current densities are applicable to stainless steel, as well as carbon steel lines.

Buried lines are stated to require a current density of 20 mA/m<sup>2</sup>.

### 3.4.2 DNV RP F103:2003

RP F103 adopts a completely different, and much less conservative, approach. It defines a single current density, applied for all stages in life, dependent only on pipeline internal temperature:

**Table 5** Recommended current densities for CP design from DNV RP F103:2003

Exposure	Current density (mA/m <sup>2</sup> )			
	<50°C	50-80°C	<80-120°C	>120°C
Non-buried	50	60	70	100
Buried	20	25	30	40

These values are to apply for all seawater temperatures and at all depths. Burial is defined as '*...sections to be subjected to trenching and back-filling*' or where '*... self burial (in soft silts) can be demonstrated*'. Sections which are only expected to be partly buried are to be considered as non-buried when calculating current demand.

Given that these recommendations for current density appear to run counter to the proposition, which forms the basis of all other standards<sup>16</sup>, that oxygen content (a function of temperature) and calcareous deposit formation (a function, inter alia, of temperature and depth) control the current required, it is worth quoting the DNV justification for this approach in full.

*'The current demand associated with cathodic protection of pipelines is related to 'leakage' of current at pores and narrow cracks or crevices in the coating, primarily in connection with field joints. Hence, there is no direct exposure of steel surfaces to seawater and the temperature at the metal / electrolyte interface is close to that of the internal fluid temperature. The cathodic current is then primarily related to hydrogen evolution, even for unburied pipeline sections, whilst reduction of dissolved oxygen has a minor contribution to the cathodic reaction. As a consequence, seawater parameters affecting oxygen supply (e.g. dissolved content of oxygen and seawater flow), hydrostatic pressure and seawater ambient temperature are less important. The cathodic current is primarily determined by diffusion and migration processes in the pores and crevices and the electrolyte resistivity. For pipelines operating above ambient seawater temperature, the temperature of the internal fluid, having a major effect on diffusion / migration processes and electrolytic conductivity, is the decisive factor for the current demand.'*

<sup>16</sup> Including DNV RP B401

Clearly it may be expected these considerations would only apply to very high integrity modern coatings such as 3-layer polypropylene, polychloroprene or thermal insulation. However, DNV RP F103 also allow their application to glass reinforced asphalt, and coal tar, enamel and to fusion bonded epoxy provided these are combined with a concrete weight coat.

### 3.4.3 Coating breakdown

The current demand on a coated structure or pipeline will increase with time as the coating deteriorates. It is, therefore, necessary to define levels of such deterioration for the types of coating under consideration. This is done by specifying two factors for coating breakdown which, taken together, define the amount of exposed bare steel at any point in the operating life. These factors are the initial breakdown factor on installation ( $f_i$ ) and the subsequent breakdown per annum ( $\Delta f$ ). For a design life of  $t$  years, the average breakdown ( $f_m$ ) is then given by:

$$f_m = f_i + (0.5 \cdot t \cdot \Delta f)$$

and that at the end-of life by:

$$f_m = f_i + (t \cdot \Delta f).$$

These factors are used in combination with the recommended current demands (section 3.4) to determine the total current required for protection.

The breakdown factors proposed by the standards were initially very conservative, predicting, for some coatings, complete coating loss in as little as 30 years. With the development of superior coatings, and the accumulation of service experience, values have become more realistic. However, as with current densities, the approaches to coating breakdown are different for the two extant standards for pipelines. Again they are described separately in what follows.

### 3.4.4 ISO 15589-2: 2004

Factors suggested in the ISO 15589-2 standard are reproduced below:

**Table 6** Recommended coating breakdown factors for CP design from ISO 15589-2:2004

Coating type	Breakdown factors	
	Initial	per annum
Asphalt/coal tar enamel + concrete	0.010	0.0005
Fusion-bonded epoxy (FBE) + concrete	0.010	0.0005
Fusion bonded epoxy	0.020	0/0010
Elastomeric materials (polychloroprene or equivalent)	0.005	0.0002
Multilayer (incl. FBE primer) polyethylene (PE) and polypropylene anti-corrosion	0.005	0.0002
Multilayer (incl. FBE primer) PE/PP anti-corrosion + concrete	0.002	0.0001
Thermal insulation systems (fully bonded) <sup>17</sup>	0.002	0.0001

The standard further states that the coating breakdown factors are ‘...based on coating quality being in accordance with commonly applied industry standards’, and that they ‘.... do not include any allowance for excessive damage ... during fabrication or installation, or for field joints intentionally left uncoated, or third party damage in service ...’.

<sup>17</sup> defined by ISO as ‘... those coating systems that include, in addition to a corrosion protective coating, a layer whose specific purpose is to provide thermal insulation .....whose overall system thickness is greater than 3 mm....’



Importantly, and in contrast to DNV, the factors used are '**based on field joints having a quality equivalent to the factory applied coatings**'.

### 3.4.5 DNV RP F103:2003

DNV RP F103 provide separate breakdown factors for the individual sections of line-pipe (Table 7) and for field joints (Table 8); the latter are an order of magnitude or more higher.

**Table 7** Recommended coating breakdown factors of line-pipe for CP design from DNV RP F103: 2003

Coating type	Breakdown factors	
	Initial	per annum
Asphalt/coal tar enamel + concrete	0.003	0.0001
Fusion-bonded epoxy (FBE) + concrete	0.001	0.0005
Fusion bonded epoxy (min DFT 150 µm)	0.001	0.0003
Elastomeric materials (polychloroprene or equivalent)	0.001	0.0001
3-layer (incl. FBE primer) polyethylene (PE) and polypropylene anti-corrosion	0.001	0.0001
Multilayer (incl. FBE primer) PE/PP anti-corrosion	0.0003	0.00001
Thermal insulation systems (fully bonded)	Not mentioned	

**Table 8** Recommended coating breakdown factors of field joints for CP design from DNV RP F103: 2003

Field joint type <sup>18</sup>	Infill*	Used with	Breakdown factors	
			initial	per annum
None	PU, C or PP	All concrete clad or multilayer PE/PP	0.30	0.03
Tape or heat shrink with mastic adhesive	M, PU or C	Asphalt or coal tar with concrete	0.10	0.01
Heat shrink with PE adhesive	PU or C	Asphalt with concrete	0.030	0.003
Heat shrink with PP adhesive	None	3-layer PP	0.030	0.003
FBE	PU or C	Asphalt with concrete	0.030	0.001
FBE with PE heat shrink	PU or C	Coal tar with concrete	0.010	0.0003
FBE with PP heat shrink	None or PU	3-layer PP	0.010	0.0003
FBE with PP adhesive bonded coating	None or PU	3-layer or multilayer PP	0.010	0.0003
Polychloroprene	None	Elastomeric	0.010	0.0003

\* = mastic

PU = polyurethane

C = concrete

PP = polypropylene

<sup>18</sup>

For complete field joint descriptions, refer to DNV RP F103 and DNV RP F102

It will be noted that the line pipe factors are some 30 times lower than those used by ISO 15589-2, which implicitly allow for the effects of possibly less effective coatings on field joints. It is instructive to compare the ISO15889-2 and DNV RP F103 requirements after combining the pipe and field joint data for the latter. The following table shows overall factors for FBE and insulating coatings on a pipeline with a 25 year design life and where the field joint length represents 5% of the overall line length.

**Table 9** Example highlighting differences between recommended coating breakdown factors from ISO 15589-2: 2004 and DNV RP F103 for a typical CP design.

Source	Coating type	Coating Breakdown Factor		
		Initial	Average	Final
ISO 15589-2	3LPP	0.0050	0.0075	0.0100
	Insulated	0.0020	0.0033	0.0045
DNV RP F103	3LPP (line)	0.0010	0.0014	0.0018
	3LPP (joints)	0.03	0.07	0.11
	Combined*	0.0025	0.0049	0.0073
	Insulated (line)	0.0003	0.00041	0.00053
	Insulated (joints)	0.01	0.014	0.018
	Combined*	0.0008	0.0011	0.0015

\* Assumes field joint length is 5% of overall length

Since the effective field joint length on most lines will be significantly less than 5%, it is clear that coating breakdown factors in the DNV RP F103 approach are substantially less conservative than those of ISO 15589-2. This is consistent with DNV's stated objective to '*...remove any undefined conservatism from the CP design assumptions.*'.

The combined effect of this with the alternative approach to setting current densities results in designs to the DNV RP F103 procedures having as little as 25% of the total CP provision of ISO 15589-2: 2004 designs. Such an approach can only be viable if, as stated earlier,

- CP designs on adjacent structures are correctly executed (thus avoiding adverse current drain on the line),
- mechanical damage to the line during installation and operation (unexpectedly increasing CP current demand) is avoided

and, importantly,

- coating specification and application, especially for field joints, are of the highest quality (preventing higher than expected coating deterioration).

### 3.5 Sacrificial anodes

Both DNV RP F103 and ISO 15589-2 provide manufacturing, quality assurance and installation requirements for sacrificial anodes. In respect of sacrificial anode properties, DNV RP F103 defer to ISO 15589-2; design values provided are:

**Table 10** Design values for galvanic anode properties from ISO 15589-2:2004

Alloy	Temp. (°C)	Capacity (Ah/kg)		Potential (mV)	
		Seawater	Buried	Seawater	Buried
Al-Zn-In	<30	2500	2000	-1050	-1000
	60	2000	850	-1050	-1000
	80	900	400	-1000	-1000
Zinc	<30	780	750	-1030	-980
	30 to 50 <sup>19</sup>	780	580	-1030	-980

Neither standard refers to magnesium anode alloy. Although not usually recommended for seawater use, magnesium has been used successfully for retrofit anode installations.

### 3.6 CP design procedures

Both DNV RP F103 and ISO 15589-2 provide procedures for the satisfactory design of CP for offshore pipelines, the former providing also a comprehensive listing of the content required in a documented design. ISO 15589-2 also, in an annex to the standard, addresses facets of the overall pipeline design which impact on CP.

### 3.7 Anode distribution

Until the latest standards were issued, restrictions were recommended on the maximum distance allowable between bracelet anodes fitted to the pipe. The maximum allowable was either 200 m or 300 m.

The latest DNV RP F103 and ISO 15589-2 standards allow the use of widely spaced anodes for flowlines with high integrity coatings. For any design which results in a spacing between anodes of greater than 300 m, the design must be supported by the use of appropriate potential attenuation calculations, to ensure the maintenance of protection over the full distance between anode installations. Attenuation equations are provided in both standards, but those in the DNV document are the more detailed and complex. All require some knowledge of coating conductance, a parameter which is notoriously difficult to define.

As an alternative to bracelet anodes, this approach allows the use of anodes on structures at the ends of the pipeline, or installed, by ROV, as anode sled assemblies at intermediate points, to provide protection over substantial lengths of line. This can be of particular importance on thermally insulated production lines, where penetration of the coating at anode attachments is not recommended.

Attenuation calculation can also be used in support of anode sled designs for retrofitting lines with under-performing CP systems, thereby reducing what are usually substantial installation costs.

### 3.8 Monitoring and surveying

ISO 15589-2 provides an annex describing the requirements for monitoring of CP systems on pipelines in order to establish their effective operation. NORSOK M503 refers to the ISO 15589-2 and DNV RP B401 for inspection and anode installation.

## 4 Literature Survey

### 4.1 Approach

A review has been carried out, of the published literature, in respect of the theoretical and practical application of CP to pipelines. Only a very limited amount of information has been

<sup>19</sup> Zinc anodes cannot be used above 50°C

found specifically related to pipelines, the majority being related to uncoated steel structures. In as much as the latter is relevant to pipelines once coating deterioration has occurred, it is also discussed here.

## 4.2 Potential

The literature search has not revealed any publication that suggests that design protection potentials should be modified to account for depth.

## 4.3 Current density

### 4.3.1 Site data – uncoated carbon steel structures

The earliest systematic study of actual current densities on offshore structures appears to be that of Strømme<sup>20</sup>. This used a combination of direct current measurement and mathematical modelling, based on field gradient data, to assess protection current requirements on 'a considerable number' of North Sea structures. The data were used to inform the later recommendations incorporated in DNV standards.

Much more recently, Baptista and da Costa have reported<sup>21</sup> the results of site testing at 102 m, 290 m and 975 m in the Campos Basin offshore Brazil. In presenting their results, they reported the minimum initial current density that was found to be sufficient to achieve cathode polarisation to  $<-0.8$  V in 20 days or less. The results are summarised below.

**Table 11** Cathodic current densities - Campos Basin<sup>30</sup>

Field	Depth (m)	Temp (°C)	Current Density (mA/m <sup>2</sup> )	
			Initial	mean
Linguade	102	18	208	55
Albacora	290	12	291	120
Marlim	975	4	363	130

These data confirm the DNV and ISO recommendations that greater initial and mean current densities are required to achieve protection at lower temperatures and, perhaps, as depth increases, although the effects of these two parameters cannot be separated in these data.

Hartt et al report<sup>22</sup> on data from instrumented steel plates exposed at a depth of 899 m in the Gulf of Mexico for a little over a year. Steady state current densities of ca. 100 mA/m<sup>2</sup> were recorded on pre-rusted samples, with higher values on polished surfaces. The results were compared with the results of laboratory simulations<sup>23</sup> of the operating conditions, in which lower current densities than actually occurred were observed. This serves to illustrate the difficulties of reproducing service conditions in the laboratory.

Fischer and co-workers have reported<sup>24</sup> on a substantial body of site testing in the Barents Sea ( $>73^{\circ}$ N). In contrast to the Brazilian study, the results indicate that cathodic current density requirements decrease with depth.

<sup>20</sup> R Strømme, 'Review of offshore CP design criteria based on in-situ current density measurements', proc. Conf 'UK Corrosion '85, publ. Institute of Corrosion, Leighton Buzzard, UK

<sup>21</sup> W. Baptista and J.C.M. da Costa, 'In Situ Acquisition of Cathodic Protection Parameters, Materials Performance **36** (1) 9, 1997

<sup>22</sup> W H Hartt, S Chen and S Wolfson, 'Deep water cathodic protection – field deployment results', paper 02020, proc. conf. Corrosion 2002, NACE, Houston, USA

<sup>23</sup> W H Hartt and S, 'Deep water cathodic protection – laboratory simulation experiments', paper 01501, proc. conf. Corrosion 2001, NACE, Houston, USA

<sup>24</sup> K.P. Fischer, W.H. Thomason and S. Eliassen, *CP in Deep Water : The Importance of Calcareous Deposits and the Environmental Conditions*, Paper no. 548 CORROSION/96 NACE, Houston (1996)

**Table 12** Polarization data from 0.9 years exposure in the Barents Sea<sup>24</sup>

Depth (m)	Current Density (mA/m <sup>2</sup> )			Potential (mV)	
	initial <sup>25</sup>	final	mean	final	mean
50	300	138	222	-906	-803
100	300	127	193	-910	-844
471	180	113	154	-800	-815
471	300	85	131	-925	-958

The table shows that, for a given design value of cathodic current the subsequent protective quality of the calcareous deposit increases with depths down to ~470 m. Although this is in agreement with their earlier work<sup>26</sup> for the Northern North Sea and Northern Norwegian Sea, it runs counter to the experience noted above for the warmer waters of the Gulf of Mexico or the Campos Basin. Nevertheless, the target initial design current densities implied by the work in the Barents Sea (~300 mA/m<sup>2</sup> at 471 m) compare reasonably with the minimum adequate initial current densities in the Campos Basin (>291 mA/m<sup>2</sup> at 290 m, and >363 mA/m<sup>2</sup> at 975 m).

Fischer has also reported<sup>27</sup> on CP current requirements on the Norwegian continental shelf which are important for future developments. Again, in accordance with his own earlier data, but counter to those for the warmer water studies, polarisation was easier to achieve in deeper waters. At depths of 100 and 200 m, design values of 220 mA/m<sup>2</sup> initial current could not produce polarisation to protected levels, apparently due to relatively high flow rates at the test locations. At 600 and 1300 m protection was achieved in most cases, with current densities after a few days exposure stabilising in the range 95 to 177 mA/m<sup>2</sup>.

#### 4.3.2 Site data – coated pipelines

Only one paper has been located detailing test results on a subsea pipeline. This is presumably because the initial polarisation current, on a very limited amount of bare steel, rapidly produces polarisation, and overall currents are, therefore, very small and difficult to measure in practice. This is confirmed by the study being carried out on the Northstar pipeline in the Barents sea<sup>28</sup>, where measured current outputs were less than 100 µA. The coating in this case was dual-layer FBE.

#### 4.3.3 High strength and corrosion resistant alloys

There is an increasing interest in employing alloys other than carbon steel in the exploitation of hydrocarbons offshore, particularly where it is necessary to operate in deeper waters or to handle aggressive reservoir fluids. Examples of such alloys include high strength low alloy (HSLA), austenitic or duplex stainless steels. Aluminium is also encountered in the form of a flame sprayed coating on steel. Some of these materials will require CP to prevent general corrosion (e.g. aluminium and HSLA steels). Depending upon their compositions, the stainless steels or nickel based alloys may require CP to prevent pitting or crevice corrosion.

However, irrespective of whether or not these alloys require protection in their own right, they will usually be metallurgically continuous with protected components. They will, therefore, draw current from the CP system.

<sup>25</sup> Initial values are those used in the design calculations: mean and final values are as-measured.

<sup>26</sup> K.P. Fischer, T. Sydberger and R. Lye, *Field Testing of Deep Water Cathodic Protection on the Norwegian Continental Shelf*, Materials Performance **27** (1) 49, 1988

<sup>27</sup> K P Fischer, 'Field testing of CP current requirements at depths down to 1300 m on the Norwegian continental shelf from 63 to 67°N', paper 361, proc. conf. 'Corrosion 99, NACE, Houston, USA

<sup>28</sup> J P La Fontaine, T G Cowin and J O Ennis, 'Cathodic protection monitoring of subsea pipelines in the Arctic Ocean', Materials Performance, **40** (4), 20, 2001

In an extensive programme, Foster and Moores of the Canadian Navy studied<sup>29</sup> the cathodic current requirements of a variety of materials, including: aluminium bronze, naval brass, cupro-nickel, austenitic stainless steel and titanium. They concluded that:

*'In designing a cathodic protection system for a structure containing several alloys, the current requirement for practical purposes is independent of the alloy composition'.* This is perhaps not surprising given that the dominant cathodic reaction at the protection potential is the oxygen reduction reaction. Lye reports<sup>30</sup> no practical difference between different types of stainless steel and carbon steel, and concludes that the same current densities may be used in all cases.

In the testing programme, referred above<sup>20</sup>, Baptista and da Costa also polarized some panels of type AISI 316 stainless steel. Again the data indicate that similar mean current density to carbon steel was required in the case of stainless steel. In the Barent's Sea trials<sup>25</sup>, Fischer et al included two super-austenitic stainless steel samples. At 100 m depth, the mean and final currents on the stainless steel specimen were lower than on the carbon steel.

#### 4.4 Calcareous deposits

The formation of calcareous deposits is crucial to the operation of CP, particularly on uncoated structures. Without these deposits it would be impractical to supply the protection currents that would then be required. As a result, there has been a large body of work carried out on the mechanism of formation of these deposits, both in-situ, and in the laboratory.

Following a review<sup>31</sup> carried out by Thomason and Fischer, NACE produced a comprehensive state-of-the-art report<sup>32</sup> on CP design considerations for deep water structures in 1992. That report comprised a survey of 97 references published prior to 1991. In their review NACE pay particular attention to the issue of calcareous deposit formation, reiterating the point that *"the optimum CP design is achieved by inducing a high current density on unpolarized steel immediately upon immersion in order to promote rapid cathodic polarization and formation of high-quality calcareous deposits"*. It confirms that the quality of the calcareous deposit depends on a number of factors, in particular:

- dissolved oxygen content,
- temperature,
- salinity,
- pH,
- currents
- and microbial films.

These factors inter-relate with each other, and with the water depth, in a complex manner. In particular, deeper waters tend to be colder, of lower pH and depleted in dissolved oxygen compared to the near surface strata. As Dexter and Culberson explain<sup>33</sup>, the lowering of the dissolved oxygen is due to the biochemical oxidation of organic matter. This in turn produces CO<sub>2</sub>, which lowers the pH. The extent to which these parameters alter with depth

<sup>29</sup> T. Foster and J.G. Moores, *Cathodic Protection Current Demand of Various Alloys in Seawater*, paper 295 CORROSION/86 NACE, Houston (1986)

<sup>30</sup> R.E. Lye, *Current Drain to Cathodically Protected Stainless Steels in Seawater*, Materials Performance **27** (10) 24 1988

<sup>31</sup> W.H. Thomason and K.P. Fischer, *Cathodic Protection of Steel Structures in Deep Water : A Review*, Paper no. 6588 Proc. 23rd Offshore Technology Conference (1991)

<sup>32</sup> Publication 7L192, *Cathodic Protection Design Considerations for Deep Water Structures*, NACE, Houston (1992)

<sup>33</sup> S.C. Dexter and C. Culberson, *Global Variability of Natural Sea Water*, Materials Performance **19** (9) 16, 1980

is dependent on the geographical location and the seasons. In the North Atlantic the dissolved oxygen content reduces from ~5 mg/l to ~3.5 mg/l over the first 1000 m of depth, while for a North Pacific location, of comparable latitude, the reduction is from ~6.5 mg/l to ~1 mg/l over the same depth. At both sites the oxygen levels then increase at depths beyond ~1000 m. pH values fall in the same way, and at the Pacific location the pH value fell from ~8.25 at the surface to 7.60 at 1000 m while at the North Atlantic test location it fell to ~7.96.

The implications of these changes are quite profound for calcareous scale formation, and hence for CP design. The trend towards lower dissolved oxygen contents suggests both lower natural corrosion rates and lower cathodic current requirements. By contrast, the lowering of pH and temperature, each of which increase the solubility of the calcareous compounds, reducing their protective capability and increasing current demand. As a result, CP systems for deep water structures need to be sized for greater mean-life current densities than their shallower counterparts.

The varied effects of the environment parameters on calcareous deposit formation, as deduced from the literature, can be summarised as follows:

**Table 13** Summary of the effects of environmental factors on calcareous deposit formation

Parameter	Effect on calcareous deposit	Effect on other parameters
Temperature	Decrease impairs formation	Lower temperature increases resistivity and O <sub>2</sub> and CaCO <sub>3</sub> solubility
Salinity	Probably negligible	Increased salinity decreases resistivity and O <sub>2</sub> solubility
Dissolved O <sub>2</sub>	Decrease impairs formation	-
pH	Decrease impairs formation	Lower pH temperature increases CaCO <sub>3</sub> solubility
Flow	Uncertain. Very high flow may remove deposit.	Reduces O <sub>2</sub> flux at surface
Pressure	Inconclusive	Complex
Biofouling	Complex	Reduces O <sub>2</sub> flux at surface Can lower pH

Attempts have been made<sup>34+35+36</sup> to develop algorithms to predict CP requirements from the environmental conditions at a given location. Setting the current density design parameters for bare steel structures in deep locations is, therefore, problematical. Although Blackburne and Griffin state categorically that:

*‘The user need only select a specific geographical co-ordinate of interest from the list provided, and the program will calculate current density requirements and amount of surface coverage of calcareous deposits for the whole range of depths at the specified location. The data from this program can then be input into a cathodic protection model*

<sup>34</sup> J-F. Yan, T.V. Ngugen, R.E. White and R.B. Griffin, Mathematical Modeling of the Formation of Calcareous Deposits on Cathodically Protected Steel in Seawater, J. Electrochem Soc. **140** (3), 733 (1993)

<sup>35</sup> J-F. Yan, R.B. Griffin and R.E. White, Parametric Studies of the Formation of Calcareous Deposits on Cathodically Protected Steel in Seawater, J. Electrochem Soc. **140** (5), 1275 (1993)

<sup>36</sup> P.N. Blackburne and R.B. Griffin, *Mathematical Model for Predicting Calcareous Film Formation*, paper no. 562 CORROSION/96 NACE, Houston (1996)

which will determine the amount and size of sacrificial anode required to protect the offshore structure',

Fischer et al's view<sup>23</sup> that 'There is today no model which can accurately enough predict CP current requirements for a given location in the oceans ....' is much more realistic. The uncertainties involved are also highlighted<sup>37</sup> by Hernández, Hartt and Videla who conclude that .... *biofilms and calcareous deposits, formed simultaneously at the time of initial metal immersion, can either enhance or decrease the effectiveness of cathodic protection.*

#### 4.5 Deep water installations

Reference is made, in most of the publications referred to in sections 4.3 and 4.4, to the effects of deep water on both calcareous deposits and consequent current density requirements. The parameters affecting calcareous deposits vary as follows with increasing water depth:

Temperature:	Decreases (but not uniformly)
Salinity:	Generally increases
Dissolved oxygen:	Initially decreases, but may reach a minimum and then increase
pH:	Initially decreases, but may reach a minimum and then increase
Flow:	Generally decreases, but bottom currents may be present in some locations
Pressure:	Increases proportionally
Biofouling:	Can be found at any depth.

In general, as acknowledged by the recent revisions of DNV and ISO, design current densities must be increased with depth to allow for the increased difficulty of forming and maintaining calcareous deposits at depth.

#### 4.6 Sacrificial anodes

The operating characteristics of both zinc and aluminium sacrificial anodes have been well established for over 30 years. There is no reference in the literature to any adverse effects of depth, dissolved oxygen, normal seawater pH variations or flow. They are, however, affected by elevated temperatures, albeit outside the normal range for ambient seawater, especially when buried<sup>38</sup>. A useful summary<sup>39</sup> has been provided by Schrieber and Murray. Magnesium does not find general use in offshore cathodic, protection, although one offshore pipeline retrofit project<sup>40</sup> has taken advantage of its more negative operating potential.

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<sup>37</sup> G. Hernández, W.H. Hartt and H.A. Videla, *Marine Biofilms and Their Influence on Cathodic Protection : A Literature Survey*, Corrosion Reviews **12** (1-2) 29 (1994)

<sup>38</sup> C.J. Houghton and V. Ashworth, *The Performance of Commercial Zinc and Aluminium Anodes in Hot Seabed Mud*, Mat. Perf., **21**(7), 20 (1982)

<sup>39</sup> C.F. Schrieber and R.W. Murray, *Effect of Hostile Marine Environments on the Al-Zn-In-Si Sacrificial Anode*, Corrosion/88, paper no. 32, NACE (1988)

<sup>40</sup> W R Jacob, 'High current output cathodic protection retrofit on a 6" submarine flowline', Proc. conf 'Pipeline protection', BHR Group, London, (1997)



A recent development has been that of an aluminium gallium alloy<sup>41</sup> with an open circuit potential around –830 mV, which, once (and if) proven, could find application for the protection of materials otherwise susceptible to HISC. A recent assessment<sup>42</sup> by the Naval Research Laboratory (USA) appears to cast some doubt on the viability of this material for large scale use.

#### 4.7 Anode distribution – attenuation calculation

As described in section 3.8, the latest design codes allow widely spaced anodes to be used on pipelines with sufficiently robust coatings, provided that their use is supported by appropriate attenuation calculations. As a result there have been a number of recent papers<sup>43:44:45:46:47</sup> published in this regard. The subject is complex, and no attempt has been made in this review to evaluate the various equations proposed. It is, however, clear that this is an area where properly validated calculation approaches are essential if protection is to be maintained over long lengths of line throughout their operating life.

#### 4.8 Pipeline CP performance and retrofits

It is common experience that most pipeline CP designs, if performed to the codes, have been conservative and show every sign of providing protection up to, and, indeed, well beyond their design life. This is acknowledged<sup>48</sup> by Britton, who, however, then goes on to say that *'Problems have been found on pipelines that become electrically shorted to platforms, pipelines without weight coatings that have anodes detached during the pipelay process and pipelines fitted with aluminium anodes of poor quality that have failed to activate.'* To which could be added, from the review author's own experience, failure of, or installation damage to, field joint coatings, loss of adhesion of coating, inadequate CP provision and use of inappropriate coatings. Virtually all of these can be tracked back to failures of quality control, and commercial sensitivities usually ensure that no information on them reaches the public domain. Only two cases have been identified in this review. The first describes<sup>49</sup> installation damage that was mitigated using anodes retrofitted using underwater friction welding. The second, and more unusual, case was that of a flowline with an EPDM rubber thermal insulation coating<sup>39</sup>, which proved, due to having an excess of carbon-black filler, to be both electrically conductive and cathodic to the steel pipe. The need for a high current to prevent corrosion led to the use of retrofitted magnesium anode sleds.

The extension of life of pipelines beyond original design life in fields where improved extraction techniques (like gas re-injection etc.) can be used, the connection of new developments to existing pipelines, and, indeed the inappropriate use of attenuation equations on pipelines now being built with CP designed to the latest codes, could all require the fitting of retrofit CP systems. These could be in the form of piggy-back anodes, or, most likely, anode sleds, and innovative installation solutions will be needed, especially in deeper waters. Some work<sup>50:51</sup> has been reported in this area.

<sup>41</sup> J-P. Pautasso, H. le Guyader and V. Debout, 'Low voltage cathodic protection for high strength steels: part 1 definition of a new aluminium galvanic anode material', Paper 725, conf. 'Corrosion 98', NACE, Houston (1998)

<sup>42</sup> E Lemieux, K E Lucas, E A Hogan and A M Grolleau, 'Performance evaluation of low voltage anodes for cathodic protection', Paper 02016, Conf. Corrosion 2002, NACE Houston USA, 2002

<sup>43</sup> P Pierson, W H Hartt and K P Bethune, 'Potential attenuation and anode current output determination alternatives for marine pipelines and risers', paper 628, conf. Corrosion99, NACE, Houston, USA, 1999

<sup>44</sup> D K Lysogorski, W H Hartt and P Ananthakrishnan, 'A modified potential attenuation equation for cathodically polarised marine pipelines and risers', paper 03077, conf. Corrosion2003, NACE, Houston, USA, 2003

<sup>45</sup> D K Lysogorski, and W H Hartt, 'A potential attenuation equation for design and analysis of pipeline cathodic protection systems with displaced anodes', paper 03197, conf. Corrosion2003, NACE, Houston, USA, 2003

<sup>46</sup> J P La Fontaine and G Gibson, 'Cathodic protection design of pipelines using an improved attenuation model', paper 04091, conf. Corrosion2004, NACE, Houston, USA, 2004

<sup>47</sup> S N Smith and P Sloan, 'Attenuation analysis of survey data on a subsea pipeline with retrofit anodes', paper 05082, conf. Corrosion2005, NACE, Houston, USA, 2005

<sup>48</sup> J Britton, 'Offshore pipeline CP retrofit strategies' paper 02018, conf. Corrosion2002, NACE, Houston, USA, 2002

<sup>49</sup> R H Winters and A C Holk, 'Cathodic protection retrofit of an offshore pipeline', paper 479, conf. Corrosion97, NACE, Houston, USA, 1997

<sup>50</sup> J A Brandt, 'Sacrificial anode retrofits: innovative solutions for the challenge of deepwater and other complex marine environments', paper 479, proc. Corrosion97, NAVCE Houston, USA, 1997

## **5 Pipeline and Flowline Coatings**

### **5.1 International guidelines**

There have been a number of guidelines and standards produced relating to the various different coating systems used on offshore pipelines and flowlines. These relate variously to the following coating systems.

- Coal Tar or Asphalt (bitumen) enamel coatings
- Coal tar epoxy coatings
- Conventional epoxy coatings
- Fusion bonded epoxy coatings – single and dual coat
- 3 layer FBE/polyethylene or polypropylene coatings
- Thermal metal spray
- Foam coatings
- Polychloroprene (Neoprene) coatings
- These are discussed in more depth in Section 5.3

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<sup>51</sup> S N Smith, 'A new approach to the design of retrofit sacrificial anodes', paper 01504, conf. Corrosion2001, NACE, Houston, USA, 2001

## 5.2 Coating and related standards

**Table 14** Commonly referenced standards related to pipeline coatings

Source	Ref	Title	Ref issue date
AWWA	C203	Coal tar enamels	2002
BS	EN 12474 : 2001	Cathodic Protection of Submarine Pipelines.	2001
BS	4164 (up to 1987)	Coal tar enamels	2002 Rev.
BS	EN 14161 : 2003	Petroleum and natural gas industries. Pipeline transportation systems. <sup>52</sup>	2003
CSA	Z245.21-98	External polyethylene coating for pipe.	1998
CSA	Z245.20-02	External fusion bonded epoxy coatings for steel pipe.	2002
DNV	RP B401	Cathodic Protection Design	2006 Rev.
DNV	OS F101	Submarine Pipeline Systems	2005 Rev.
DNV	RP F102	Pipeline Field Joint Coating and Field Repair of Linepipe Coating.	April 2006
DNV	RP F103	Cathodic Protection of. Submarine Pipelines by Galvanic Anodes	April 2006
DNV	RP F106	Factory Applied External Pipeline Coatings for Corrosion Control	April 2006
ISO	13628	Petroleum and natural gas industries – Design and operation of sub-sea production systems (Parts 1 through 9).	1999-2006
ISO	20340	Guidance for coating selection for offshore structures. <sup>53</sup>	2003
ISO draft	DIS 21809-1	3-layer PE and 3-layer PP	2007
ISO draft	DIS 21809-3	Field joint coatings	2007
NACE	RP0394-2002	Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating.	2002
NACE	TM 0204	Exterior Protective Coatings for Seawater Immersion Service. <sup>53</sup>	2004
NORSOK	U-001	Sub-sea production systems. This supplements ISO 13628.	2002 Rev. 3
NORSOK	M-501	Surface preparation and protective coating (for offshore installations).	2004 Rev. 5
NORSOK	M-503	Cathodic Protection	2007 Rev. 3
Transco	CW-6	The external protection of steel line pipe and fittings using fusion bonded powder and associated coating systems.	1993

There are also numerous in-house standards.

<sup>52</sup>

This standard supersedes BS 8010-1 : 1989, BS 8010-2 : 1992, BS 8010-3 : 1993

<sup>53</sup>

ISO 20340 and TM 0204 are evaluated and compared in Corrosion NACEpo 2006, Paper No. 06033

## **5.3 Coating systems**

### **5.3.1 Summary**

These are discussed under separate coating types below.

In general terms, bitumen and coal tar type coatings were the first to be used for coating pipelines and have been used very successfully for over 100 years for buried pipelines and also for fully immersed pipelines. Some 40 to 50 years ago coal tar epoxy resin coating systems started to be used and again have proved to be generally very successful. However, in more recent times, these coating systems have been replaced by Fusion Bonded Epoxy (FBE) and 3-layer polyolefin coatings (3LPO). In some cases, but not necessarily for sub-sea pipelines, pure epoxy and polyurethane coating systems have been / are being used.

These more modern coatings – FBE and 3LPE (3-layer polyethylene) – are much more expensive but in spite of that are still widely used. They have the disadvantage of having a far smoother finish, which can cause problems with lack of friction with concrete weight coatings.

In the USA and UK, FBE is the preferred coating system but European companies prefer 3-layer polyethylene or 3-layer polypropylene.

According to a NACE conference paper in 2006 <sup>54)</sup> in most areas of the world, three layer polyolefin coatings (3LPO) account for between 65% and 90% of all new coatings for pipelines. The exceptions are Africa and the Middle East where use is between 45% and 50% and USA and Canada where 3LPO only accounts for some 15% of new coatings. Fusion bonded epoxy powder makes up most of the remainder, with a few regions still using bitumen or coal tar enamel at a rate of 5% to 20%.

Some pipelines require insulation against heat loss to keep the contents flowing. Here polyurethane, epoxy and polypropylene foams may be used.

### **5.3.2 Coal tar or asphalt (bitumen) enamel coatings**

Coal tar enamel coatings have been used successfully for the protection of steel pipelines for over 100 years. The early products were mixtures of crude pitch and solvents and were brittle at low temperatures and soft and sticky at warmer temperatures, which made them difficult to handle. Later developments included the addition of inert fillers to improve their properties and make them more easily handled. The introduction of fibreglass wraps improved the mechanical strength of these coatings and reduced impact damage during handling and installation. The major use is for buried pipelines.

Whilst coal tar enamels can contain carcinogenic materials, asphalt tends to be more environmentally friendly.

With the advent of offshore oil and gas pipelines, particularly in the North Sea, where concrete weight coatings were introduced, coal tar enamel proved to be an excellent choice of coating since concrete would adhere to it. The initial primers used were slow drying pitch solutions but these were replaced in the 1960's with synthetic resin primers based on chlorinated rubber. More recently these have been replaced with epoxy primers which increase adhesion and improve the temperature resistance of the coating system.

Today, surface preparation is by grit blasting followed by application of the epoxy primer ( to a pre-warmed pipe) and then the enamel coat is hot applied with inner and outer wraps of glass fibre mats. These materials generally give good results.

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<sup>54)</sup> Three layer Polyolefin coatings: Fulfilling their potential? Argent, C and Norman, D, NACE Corrosion Conference 2006

With the correct choice of materials, in-service temperatures within the range  $-30^{\circ}\text{C}$  to  $+95^{\circ}\text{C}$  are possible, with a maximum temperature of  $115^{\circ}\text{C}$  under a concrete weight coat.<sup>55</sup> Thickness range for the coal tar enamel is generally in the range 3 – 5 mm.

According to a paper written in October 2001<sup>56</sup>, “Offshore pipelines operating at ambient temperatures (ref. in 2001) have traditionally been coated with hot applied coal tar or asphalt (bitumen) enamel coatings and they are probably the cheapest of the available coatings. They are applied over chlorinated rubber primers<sup>57</sup>, reinforced with non-woven glass fibre wraps and applied in a thickness of at least 6-7 mm. The rough surface of these coatings normally eliminates the risk of slippage between coating and concrete due to tensioning. The experience with asphalt and coal tar based thick film coatings is mainly good on offshore submerged pipelines, where a high quality concrete weight coating offers an effective shield against mechanical damage. The majority of oil and gas pipelines in the North Sea are coated with bitumen enamel and the rest mainly with coal tar enamel.”

Coal tar enamel coatings have limited flexibility at very low temperatures but are still adequate if applied to a properly blast-cleaned surface and handled with care during pipe laying.

Bituminous coatings are being replaced all over the world because of environmental laws and the gradual deterioration of these coatings with time. Life expectancy is considered by many experts in the field to be lower with current systems than those applied some 30 or more years ago due to the lowering of the quality of the coal tar/asphalt/bitumen now available.

### **5.3.3 Coal tar epoxy coatings**

These coatings consist of an epoxy resin with the addition of selected grades of coal tar, cross-linked with an amine, amine adduct, polyamide or isocyanate curing agent. The epoxy resin used may be a liquid resin or more often a solid resin in solution. They have been around for very many years and have been used very successfully for pipeline coatings. Because of changes in the production of coal tars the need to reformulate products became necessary. However, such coatings still provide excellent corrosion protection. Systems have been developed which are 100% solids and suitable for application using hot 2-component spray equipment. These systems have a pot-life of about 30 minutes.

Coal tar epoxies have been used for some 30 to 40 years with no major problems, in particular in the Morecambe Bay area and elsewhere. However, with gradual changes in the properties of the coal tars used, coating properties have gradually declined such that modern coal tar epoxies do not perform as well as older systems, with a commensurate reduction of life expectancy. No figures are available to compare life expectancy of old and new systems but industry experts have formed this opinion.

### **5.3.4 Conventional 2-pack epoxy coatings**

These comprise an epoxy resin cross-linked with an amine curing agent. They are generally spray applied and can be solvent based or solventless or solvent free. These latter are usually hot applied using heated 2-component spray equipment. They give good performance and long service life when correctly applied to a grit blast cleaned surface. They are less well used externally on pipelines than some of the other systems.

These coatings are often used for field joints and the repair of other damaged coatings, particularly since some can be applied by brush or roller to a suitably prepared surface.

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<sup>55</sup> Coal Tar Enamel, Stott, B, 31 May 2001, PCI

<sup>56</sup> BalticPipe Offshore Pipeline – Environmental Impact Assessment, October 2001 – Appendix J

<sup>57</sup> No longer used – not VOC (volatile organic compounds) compliant, superseded by 2-pack epoxies.

### 5.3.5 Fusion bonded epoxy coatings (FBE)

These comprise the application of specially formulated epoxy powders to the surface of a pre-heated pipe where the powder rapidly melts, fuses and cures to give a pinhole-free coating. They can be used alone or as the first layer of a 3-layer polyolefin coating system – see below. FBE is generally applied as a single coat system but can be applied in 2 coats. Where 2 coats are applied the second coat is applied immediately after the first coat and while the pipe is still hot.

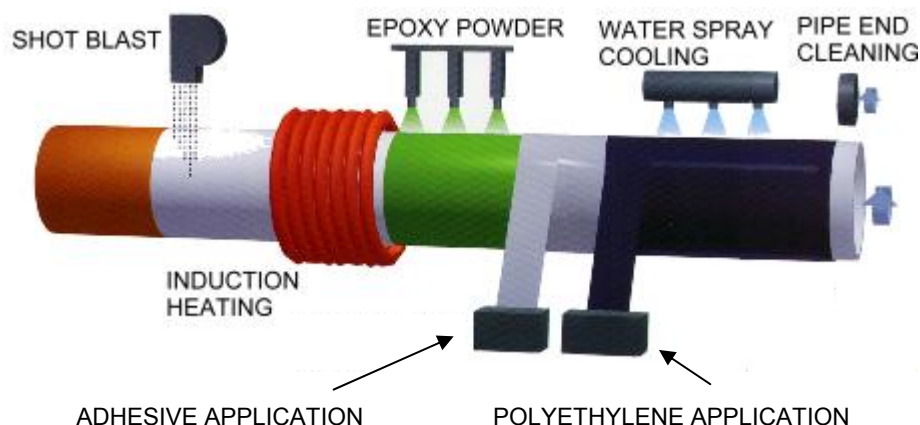
The single coat process is shown as the first stage of the 3LPE process in the diagram below. Most pipelines are coated externally as illustrated in the diagram but it is also possible to coat pipes by dipping the pre-heated pipe in a fluidised bed of epoxy powder. With dip coating both the external and internal surfaces are coated. Dip coating is also useful for coating bends and other components less suited to production line coating.

The use of FBE alone has proved to be very successful, with no reported disbonding failures. Single coat FBE has proved to be very successful on flow lines.

### 5.3.6 3-Layer Polyolefin coatings (3LPO, 3LPE)

3-layer polyolefin coatings comprise the application of a single coat of fusion bonded epoxy followed immediately by an extruded layer of a copolymer adhesive immediately covered by an extruded layer of polyethylene or polypropylene. The process is illustrated in the diagram below.

**Figure 2** Schematic of the 3-layer polyolefin coating process



Polyethylene has been the dominant outer layer for 3LPO systems but polypropylene is increasingly being used with more demanding applications, particularly where higher operating temperatures are encountered and at greater depth.

One disadvantage of 3LPO (3LPE) coatings which has become apparent over the last 5 years or so is the tendency of the coating to disbond at the steel FBE interface. This can lead to moisture and oxygen penetration and hence surface corrosion of the steel pipe. Another disadvantage is the cathodic shielding effect caused by the coating, which prevents effective steel protection.

The maximum recommended operating temperature for polyethylene coated pipes is 85°C whereas polypropylene coated pipes can withstand an operating temperature up to 110°C.

A 2 mile long high temperature subsea pipeline coated with a high temperature FBE plus a chemically modified polypropylene is reported to have performed well.<sup>58</sup>

Other pipelines coated with FBE and a concrete weight coat include an X65 pipeline where the FBE is 0.4 mm thick and 0.7 mm thick under the concrete weight coat and the Hangzhou Bay project where the FBE is covered with a concrete weight coat and an outer wrap of polyethylene.

#### **5.3.7 Thermal metal spray**

Thermal metal spraying comprises the spraying of either molten aluminium or zinc to a thoroughly blast cleaned steel surface. Thermal sprayed aluminium is used to protect pipes under syntactic foam insulation.

#### **5.3.8 Foamed coatings**

These can be epoxy and polyurethane syntactic foams, syntactic polypropylene foam and closed cell polypropylene foam. In the case of syntactic foams these incorporate generally hollow glass spheres but silica or ceramic microspheres can also be used. The foam generally is moulded in 2 halves to fit around the pipe. Because of their low density these foams give buoyancy to the pipeline.

The importance of such foam systems is to insulate the pipeline against heat loss and thus allow waxy crude oil to be transported over long distances without the wax solidifying and blocking the pipe. The thermal insulation value can be varied, as can the density, by the volume of microspheres, their wall thickness and particle size used when manufacturing the syntactic foam. The thickness of foam used for insulation is also a factor which needs to be taken into account.

With polypropylene foam, this only contains small discrete closed air bubbles rather than glass microspheres. Because polypropylene is a thermoplastic material it is subject to creep. Creep depends both on temperature (gradient) and hydrostatic pressure and needs to be taken into account when designing a pipeline to use this material for thermal insulation. By careful selection of material, closed cell polypropylene foam can be used down to a depth of 2000 meters.<sup>59</sup>

With all foam systems, one of the most important factors to be considered in the selection process is the ability of the foam to withstand the hydrostatic pressure exerted by the depth of water where the pipeline is to be laid. Syntactic foams are available in a range of densities suitable for most needs.

Once the foam sections have been applied these are held in place with an extruded PE or PP wrap.

#### **5.3.9 Polychloroprene (Neoprene) coatings**

A continuous strip of polychloroprene is wound around a pipe and then heat cured in an autoclave. The complete system consists of a primer, a bonding agent and an outer layer of polychloroprene. The autoclave process hot bonds the polychloroprene to the pipe surface. It can be used on pipelines operating up to a temperature of 95°C. Coating thickness can range from 3 mm up to 25 mm.

With any of these coating systems it is essential that the appropriate standards / specifications are closely followed. When failures do occur, these can often be attributed to poor surface preparation, surface contamination and excessive dust or blast cleaning debris on the surface of the pipe prior to application of the FBE.

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<sup>58</sup> Corrosion protection program for high temperature subsea pipeline, Surkein, M et al, NACE Corrosion 2001, Paper No. 01500.

<sup>59</sup> High performance polypropylene thermal insulation for high temperature and deep water applications. Hansen, A B and Jackson, A, Bredø Shaw Norway AS, div Thermotite

## 5.4 Field joints

Field joints are the weakest part of any pipeline coating system, since if these are improperly applied or unsuitable, or incompatible materials selected, the field joint can fail and lead to pipeline corrosion. The authors have been advised in a private communication that this has already happened in the North Sea.

Whichever field joint coating is selected it must be fully compatible with the pipeline coating system, and have similar or superior performance characteristics. This means that the pipe surface must be thoroughly prepared before application of any joint coating. Pipeline operating temperature needs to be considered because this can markedly affect the performance of the field joint material.

One of the earliest field joint coating materials to be used was mastic asphalt and it is still used today, particularly on mastic asphalt coated pipes. Various companies have developed a range of different processes and materials for field joints with the various different corrosion protection coating material used <sup>60</sup>. These include, in no order of importance, the following:

- Coal tar enamel
- Tape wraps including polypropylene tape (can be automated)
- Heat shrink sleeves
- Fusion bonded epoxy
- 2-pack liquid epoxy coating systems
- Flame sprayer polypropylene
- Injection moulded polyurethane
- Injection moulded polypropylene

Draft ISO 21809-3 – Field joint coatings, in Table 1 lists 23 different systems, not all of which are either suitable for or used on subsea pipelines.

To prevent delay in installation of the pipeline, fast setting / curing systems must be used. However, not all of these materials can be considered to be suitable for the long term immersion required for sub-sea pipelines.

Polypropylene tape wrap is applied using automated equipment to spirally wrap the tape over the prepared (and FBE coated) surface using heat to fusion bond the polypropylene to the surface. It has been used successfully off-shore.

Tapes can be cold applied over an adhesive or hot applied to bond them to the surface.

Heat shrink sleeves are used over an epoxy primer. Heating the cross-linked polyethylene sleeve causes it to shrink and the adhesive on the back of the sleeve to bond to the epoxy primer.

FBE can be applied as a field joint material to ensure compatibility with the existing FBE coating. This can be carried out using automated equipment. Many thousands of field joints have been coated with FBE both for subsea and buried pipelines.

Liquid multi-component systems can be applied to a suitably prepared surface. These provide an excellent adhesive bond to the pipe and factory applied coating at the overlap areas. These are based on fast curing epoxy or polyurethane systems. Preheating of the pipe and components may be necessary at low ambient temperature. Also, a heated post-cure may be necessary to develop full cure. Problems were experienced with this type of system by BP on the AGT pipeline project when low and sub-zero temperatures were encountered.

<sup>60</sup>

The “other class” of pipeline coatings – G de Vries, The Southern African Institute of Mining and Metallurgy 8<sup>th</sup> International Corrosion Conference.



Flame sprayed polypropylene provides full compatibility with 3-layer PE and 3-layer PP. The complete system relies on abrasive blast cleaning the pipe, applying a layer of FBE plus chemically modified polypropylene. The flame sprayed polypropylene is then applied to build the whole field joint up to the required thickness.

Injection moulded polyurethane can be used offshore for coating on-line prior to spooling. It is incompressible and therefore suitable for deep water applications according to one company who developed the process. It can be used with thin film and multi-layer polyethylene or polypropylene coating systems.

## **5.5 Lifetime of coating systems**

Sub-sea pipelines are generally protected both with coating systems and sacrificial anodes. These, coupled with regular inspection of the installed pipelines, have resulted in very few external corrosion problems. Where such problems have arisen these have generally been restricted to the failure of field jointing materials. Discussions with the head of corrosion for a major oil and gas operator have confirmed this.

When flowlines and pipelines are regularly inspected by divers and/or ROV's (remote operated vehicles) any anode depletion or other defects are noted and rectified. This preserves the life of the pipeline.

Protection of sub-sea pipelines is further enhanced by the presence of marine fouling and where the coating is damaged to expose the steel, by calcareous deposits from polarisation of the pipe.

Since coated pipes are normally 100% holiday detected during manufacture and coating to check for any pinholes or other defects in the coating, this minimises any future corrosion problems.

It has been reported that an FBE coated buried pipeline was still performing well 30 years after installation.<sup>61</sup> It should be noted however, that this is a buried pipeline and not a fully immersed sub-sea pipeline.

Some data for coating breakdown criteria for 30 year lifetime are given in Table A.3 of BS EN 12474 : 2001<sup>62</sup> and summarised below.

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<sup>61</sup> NACExpo 2006 Paper 06045 – First generation of fusion bonded epoxy coatings performance after 30 years in service – A case study, T. Fore.

<sup>62</sup> BS EN 12474 : 2001 – Cathodic protection of submarine pipelines.

**Table 15** BS EN 12474 : 2001 – Table A.3

Coating system	Coating breakdown, %	
	Average	Repolarization
Three layer system polyethylene or Three layer system polypropylene One layer system fusion bonded epoxy combined with barrier coating  All with concrete weight coating	2 to 5	5 to 10
Asphalt or coal tar enamel coating plus concrete weight coat	4 to 6	6 to 12
Polyethylene or polypropylene, three layer system, without concrete weight coating	4 to 6	6 to 12
Fusion bonded epoxy, liquid epoxy or polyurethane without concrete weight coating	5 to 20	20 to 40

*These values refer both to seawater exposed and buried in the sea bed. They are strongly influenced by the quality of the coating system as applied, coating field joint and method of pipeline installation. For design lives greater than 30 years the average coating breakdown should be increased annual by 0.2% and 0.4% for final breakdown.*

Other breakdown factors are suggested in ISO 15589-2 : 2004,<sup>63)</sup> for various different types of coating. Initial breakdown factors are given as well as breakdown factors per annum for 7 different systems. With all such factors coating breakdown is based on the assumption that coating quality is in accordance with commonly applied industry standards and that no excessive coating damage is present or field joints are left uncoated. The factors given also assume that field joint coating quality is **equivalent to the factory applied coating**.

DNV RP F103:2003<sup>64</sup> gives separate coating breakdown factors for individual sections of line-pipe and field joints. RP F103 replaces RP B401, which was first issued in 1993, with the latest revision issued in 2005.

It should be noted that line pipe factors in RP F103 are some 30 times lower than those used by ISO 15589-2 : 2004 but the ISO includes field joints in these factors whereas RP F103 treats field joints separately. This implies that field joint coatings are less effective in providing corrosion protection than pipeline coatings – a situation borne out by experience. These various data are included in the sections discussing these standards under cathodic protection. For full descriptions the various standards should be directly referred to.

## 5.6 Future coating systems

The general trend is towards the use of high performance coating systems such as fusion bonded epoxy, three layer polyolefin and insulating coatings. Present indications are that these will all perform well, provided surface preparation and application is of the highest quality and application standards are rigorously followed. As yet, little or no long term performance data are available since some of these systems have not been installed subsea for a sufficiently long period of time for such data to have been accumulated. However, expectations are good for a long service life.

As with all coating systems, the weakest part of any coating is, and will continue to be, the field joint. Here, reliance will continue to be placed on the effectiveness of the CP system.

<sup>63</sup> ISO 15589-2 : 2004 – Cathodic protection of pipeline transportation systems – part 2: offshore pipelines.  
<sup>64</sup> DNV RP F103:2003 – Cathodic protection for submarine pipelines by galvanic anodes.

No cost effective systems have been developed for retro-application of protective coatings and this situation is unlikely to change in the foreseeable future.

Coating disbondment will continue to present a potential (even if minor) problem for most, if not all, coating systems, particularly with some of the thicker high performance systems where CP shielding occurs. Although some disbonding has been found with three layer polyethylene coatings on buried pipelines after destructive investigation, no reports have been found of a similar situation occurring with a subsea pipeline. No significant corrosion, as far as the authors are aware, has been found as a result of such disbonding on buried pipelines. No technology is available at present to determine coating disbondment. This is an area where developments are necessary.

## **6 Cathodic Protection and Hydrogen Induced Stress Cracking (HISC)**

### **6.1 Recent documented failures of subsea equipment**

#### **6.1.1 Overview**

In recent years there have been a number of failures of subsea equipment which have been attributed to hydrogen induced stress cracking (HISC), sometimes also referred to as hydrogen embrittlement (HE)<sup>65,66</sup>. Failures have also occurred in some pipelines and flowlines under cathodic protection<sup>65,67,68</sup>.

These failures have occurred in a range of corrosion resistant alloys (CRA) or combinations of carbon steel and CRA. The drive to use new materials and designs has been introduced to overcome challenges imposed by deepwater developments. The recent failures involving CRA have highlighted HISC as a degradation mechanism which can have a significant impact in new offshore developments.

#### **6.1.2 13%Cr supermartensitic stainless steel (SMSS)**

Two multiple failures of flowlines involving 13%Cr Supermartensitic Stainless Steel have been reported recently<sup>67,68</sup>. The first being failures of a flowline in a field operated by Statoil in 2001 and 2002 and the second being failures of two 12" diameter flowlines in the Tune development operated by Norsk Hydro at about the same time. The flowlines were all reelayed, protected using a three layer type coating system in conjunction with cathodic protection using Al-Zn-In anodes designed according to Norsok M-503, with an anode spacing of every 200m, giving a potential of about -1100mV(vs Ag/AgCl/seawater). The failures were detected during hydrotesting at ambient seawater temperatures.

Both reported failures involved cracking in the HAZ of the fillet welds which attached type 316L austenitic stainless steel doubler plates to the flowlines. A carbon steel bracket was in turn welded to the doubler plate for attaching the anode (direct welding of anodes onto 13%Cr SMSS pipe was not recommended). The fillet welds in the Statoil flowlines were made using a 25%Cr superduplex stainless steel (SDSS) filler material and in the Tune flowlines these were made using a Ni-based filler material. In addition to the failure at the anode doubler plate attachments, a second failure on the Tune flowlines was discovered at the HAZ on both sides of a girth weld under a damaged field joint coating, and further failures occurred in matching weld metal in the girth weld.

After extensive failure analyses, all of the failures were attributed to HISC of a susceptible material (HAZ or weld metal) underneath a damaged or disbonded coating. The coating faults had allowed the flowlines to become directly exposed to seawater under cathodic

<sup>65</sup> Smith L Celant M; Pourbaix A, 'A Guideline to the successful use of duplex stainless steels for flowlines', Duplex America 2000 Conference, Duplex Stainless Steels. Houston, TX, USA, 29 Feb.-1 Mar.2000

<sup>66</sup> Huizinga S, McLoughlin B, Hannah I, Paterson S, Snedden BNW, 'Failure of a Subsea Superduplex Manifold Hub by HISC and Implications for Design', Paper no. 06145, NACE Corrosion 2006 Conference, NACE international.

<sup>67</sup> Hesjevik, SM, Olsen, S and Rørvik G, 'Hydrogen Embrittlement from Cathodic Protection on Supermartensitic Stainless Steels - Case History', Paper no. 04545, NACE Corrosion 2004 Conference, NACE international.

<sup>68</sup> Mollan, R, 'Experience with 13Cr Supermartensitic Stainless Steel in the Tune Submarine Flowlines, Paper no. 05092, NACE Corrosion 2005 Conference, NACE international.

protection, and with time hydrogen was allowed to build up in a susceptible region of the flowlines (i.e the HAZ or weld metal of welds).

In the case of the fillet joint failures, the coating failure was attributed to difficulties in controlling the quality of the coating at the difficult geometry, which allowed local disbondment of the coating. Under the disbonded coating, current was thought to have flowed to the failure location even though there was only a tight crevice. In the case of one of the girth weld failures, a longitudinal crack in the field joint coating was discovered coinciding with the failure location. This damaged coating was thought to have resulted from pre-existing flaws formed during the application process. The weld metal failures occurred at uncoated or field joint coated locations.

Also significant to the failures was the presence of stress raisers coupled with the general overall stresses during hydrotesting. Acting together, the local stress levels were thought to be sufficient to exceed the yield stress of the material.

### 6.1.3 Duplex stainless steels (DSS) and superduplex stainless steel (SDSS)

Recent reported failures attributed to HISC in DSS and SDSS have consisted mainly of subsea equipment with one exception where the failure occurred in the fillet weld of an anode doubler plate in a flowline similar to that reported for the failed 13%Cr SMSS pipeline<sup>65</sup>.

Of the failures in subsea equipment, most have occurred in subsea manifolds involving heavy forgings. In 1996, HISC was identified in two forged superduplex stainless steel hubs on the BP Foinaven field development, during final commissioning of a subsea manifold, in a water depth of approximately 400m<sup>69</sup>. Cracking occurred in the machined nib regions adjacent to the weld to the 6" pipe. The manifold was uncoated and subjected to cathodic protection by aluminium anodes, giving potentials around -1050mV(SCE). The hubs were solution annealed and quenched, had approximately 50-50 ferrite to austenite phase balance and service stresses had not been applied, although pressure testing had been performed and locked-in/residual stresses had inevitably been introduced during fabrication and installation.

The failure analysis and subsequent laboratory testing<sup>70</sup> showed the cracking initiated and propagated in a coarse, aligned grain structure, produced by the forging process. Although the microstructure had good phase balance it was shown to be particularly susceptible to HISC. The presence of nitride and carbonitrides may also have been a contributing factor to the material's susceptibility to HISC. The cracking had also occurred away from the weld and HAZ, but was shown to be in the region with highest stress concentration.

More recently, in a Shell operated development, failure of a superduplex stainless steel subsea hub connection occurred during a start-up after a planned shut-down<sup>66</sup>. The failure was caused by a full circumferential crack close to the welds joining the hub to a pipe. The manifold was uncoated and protected by sacrificial anodes at a potential of -1050mV(SCE). The failure analysis attributed HISC as the cause of the failure, with the cracking originating at external stress raisers near the weld. Testing and stress analysis studies showed that local stress, due to the applied load (plus stress concentration resulting from the geometry of the hub) plus residual stresses was likely to have exceeded 80% of yield stress, a value below which no failure occurred in laboratory tests.

The reported flowline failure occurred in a 6", 22%Cr duplex stainless steel tie-in spool which had been in service for four years. The pipe had been operating at a temperature of 100°C under cathodic protection in the range of -900mV to -950mV(SCE). Cracking had occurred at the toe of a fillet weld attaching a doubler plate to the pipe on initial start-up

<sup>69</sup> Taylor TS, Pendlington T, Bird R, 'Foinaven superduplex material cracking investigation', Offshore Technology Conference, 1999, p467.

<sup>70</sup> Woollin P, Murphy W, 'Hydrogen Embrittlement Stress Corrosion Cracking of Superduplex Stainless Steel', Paper no. 01018, NACE Corrosion 2001 Conference, NACE international.

after a shut-down, with the pipe still at close to ambient seawater temperature. It was reported that the epoxy phenolic coating had been damaged, possibly by high operating temperatures during service, and when the sample of pipe was received no coating remained. Hydrogen measurement made close to the surface of the samples showed high levels of hydrogen (29ml per 100g metal compared to 4ml per 100g in the bulk and 2ml per 100g at other parts of the pipe underneath an intact coating). The pipe had also experienced a number of thermal cycles during operation causing displacement along the seabed, resulting in bending stresses. These, together with residual stresses from welding and stresses generated during start-up at the weld toe, were considered to locally exceed the threshold stress for cracking to initiate.

#### **6.1.4 Dissimilar joints**

There are few published details of failures of dissimilar joints (ie carbon steel welded to corrosion resistant alloys (CRA)), but such components have failed due to HISC and subsequent failure of the interface between alloy steel and nickel alloy weld metal buttering.

#### **6.1.5 Carbon steel**

There have been no reported failures of carbon steel pipe in subsea service for SMYS of <450MPa, but due to weight savings, higher strength pipes are becoming more attractive for use as riser material in deep water developments. Studies have shown that susceptibility to HISC increases as the strength of carbon steel pipes is increased<sup>71</sup>.

### **6.2 Summary of HISC failures**

All of the reported failures in both 13%Cr SMSS and DSS have a number of common features:

- All failures have occurred either under damaged/disbonded coating or have been uncoated.
- All have been close to sacrificial anodes.
- All have protection potentials of above (more negative than) -800mV (Ag/AgCl/seawater)
- All have occurred in regions where the materials have a microstructure susceptible to HISC.
- Most have been in regions experienced high local stress, resulting from stress concentrations and possibly residual stresses from welding.
- Many have occurred in developments which during the commission phase, although one example was where the line had been in operation for four years.
- All have occurred during periods of variable loading, some during hydrotesting and some during start-up after shut-down.
- All have occurred in ambient or near ambient seawater temperatures.

From these common factors, test data published by TWI<sup>72</sup> and ongoing work at DNV and Sintef a number of recommendations to avoid future occurrences of failures have been established. Some of these recommendations have been formalised into standards documents, most notably the recent draft DNV-RP-F112.

<sup>71</sup> Bosch C, Schroeder J, Kulgemeyer A, 'Performance of Grade X65 to X100 large-diameter pipes under various hydrogen charging conditions', Paper no. 05118, NACE Corrosion 2005 Conference, NACE international.

<sup>72</sup> Woollin P, Gregori A, "Avoiding Hydrogen Embrittlement Stress Cracking of ferritic austenitic stainless steels under cathodic protection", Proceedings of 23rd International Conference on Offshore Mechanics and Arctic Engineering, Vancouver, Canada, 20-25 June 2004, paper OMAE 2004-51203

## 6.3 CP Standards and HISC

### 6.3.1 Protection potential

It is noted that the failures in 13%Cr SMSS and DSS have all occurred in protection potentials ranging from -900mV to -1100mV(Ag/AgCl/seawater). A reduced risk to HISC has been confirmed by a number of studies at potentials less negative than -800mV(Ag/AgCl/seawater)<sup>70,73</sup>. As a result of the highlighted failures and based on test data, the recommended protection potentials have been modified to take into account the possible risks of HISC in the recent ISO 15589-2:2004 standard for 13%Cr SMSS and DSS. Protection potential ranges of -500 to -800mV(Ag/Ag/seawater) are recommended for 13%Cr martensitic and duplex stainless steels if HISC is considered to be possible (see Section 3.3).

In at least one case of a 13%Cr SMSS flowline failure it was reported that the cathodic protection system was designed according to Norsok M503 (1997 version). This highlights an area of weakness in this version of the standard and this has now been accounted for in the latest version (Revision 3 draft of NORSOK M503) which refers to ISO 15589-2:2004 for recommended protection potentials. Newer designs<sup>74,75</sup> have been proposed recently to take account of these new guidelines (see also Sections 8.3.5).

### 6.3.2 Design and material parameters

Draft Recommended Practice DNV-RP-F112<sup>76</sup> has been prepared to address the specific issue of designing subsea equipment manufactured in duplex stainless steels to avoid HISC. This essentially summarises the lessons learnt from the recent failures in DSS and test data from a number of recent joint industry projects<sup>72,77</sup> and provides guidance on allowable stress levels and materials properties with some general comments on coatings. Although not explicitly stated, many of the guidelines may also be also applicable to pipelines and flowlines.

## 7 INDUSTRY SURVEY

### 7.1 Overview

The literature review revealed little information on operating experience with offshore pipelines, almost certainly due to commercial sensitivity to putting problems into the public domain. In an attempt more accurately to assess both operating experience, and the present approach to CP design, a questionnaire was circulated to a total of 60 named individuals in operating and engineering companies.

A total of 11 replies were received, three from operators and eight from engineering design companies. The responses are summarised in the following sections:

### 7.2 Geographical areas

The geographical areas, and maximum water depths, for which respondents claim experience are tabulated below:

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<sup>73</sup> Francis R, Byrne G, Warburton GR, 'Effects of cathodic protection on Duplex Stainless Steels in Seawater', *Corrosion*, Vol 53, No.3, p234, 1997.

<sup>74</sup> Eliassen S, Børvik L, Hesjevik, SM, Axelsen B, 'Design and installation aspect of cathodic protection for high temperature insulated pipeline - A case study based on the new draft ISO standard for cathodic protection of submarine pipelines', Paper no. 04090, NACE Corrosion 2004 Conference, NACE international.

<sup>75</sup> Sjaastad A, Harald O, Hauge OJ, Lye, RE, Bårs, 'CP Design of a super 13%Cr flowline', Paper no. 04092, NACE Corrosion 2004 Conference, NACE international.

<sup>76</sup> [http://www.dnv.com/binaries/RP\\_F112\\_tcm4-184069.pdf](http://www.dnv.com/binaries/RP_F112_tcm4-184069.pdf)

<sup>77</sup> <http://www.sintef.no/units/matek/Stalmat/dokumenter/HISC2005/15%20B%E5rd%20Nyhus.pdf>

**Table 16** Survey results on geographic location

Location	Operators		Designers	
	No. responding	Depth (m)	No. responding	Depth (m)
North Sea	1	100	5	1000
Norwegian Sea	1	100	5	1000
Gulf of Mexico	1	2000	3	2750
Arabian Gulf	2	100	3	100
West Africa	1	100	8	1500
Brazil	-	-	2	1500
Irish Sea	1	100	-	-
South China Sea	-	-	1	500
Gulf of Suez	-	-	1	150
Caspian	-	-	1	300
Mediterranean	-	-	1	2150
Indian Ocean	-	-	1	25
Baltic	-	-	1	60
Australia	-	-	1	300
Indonesia	-	-	1	60
SE Asia	-	-	1	100

Thus the majority of the operating experience represented in the responses is with respect to shallow waters. Design experience covers a greater range of both depths and geographical areas.

### 7.3 Pipeline details

The following pipeline parameters were represented in the responses:

**Table 17** Survey results on pipeline details

Parameter		Operators	Designers
Exposure:	Seabed	3	-
	Trenched	3	-
	Buried	3	-
Materials	Carbon steel	2	4
	High strength steel	-	2
	Duplex stainless steels	1	6
	Flexibles	1	-
	High nickel alloy	-	3
	Titanium	-	1
Diameters	36" – 8"	2	-
	36" – 16"	1	-
Coatings	Asphalt/bitumen	2	-
	Epoxy	2	-
	3 layer polyolefin	2	-
	Concrete weight coat	3	-
	Thermal insulation	2	-
	Thermal spray aluminium	1	-
CP	Aluminium anodes	3	-
	Zinc anodes	1	-
	Impressed current	1	-
	Schottky barrier rectifiers	1	-
	'Low potential' anodes	1	-
	Bracelet anodes	3	-
	Anode sleds	2	-
	Anodes on associated structures	2	-

It is clear that the three responding operators operate a wide range of pipeline types, coatings and cathodic protection systems, including (in one case) potential control by Schottky barrier rectifiers. The reference to 'low potential' anodes may, however, be misleading: the same operator's response also indicated that potential control was 'not required'.

Two operators each had in excess of 300 km of pipeline with ages up to > 30 years. The third reported 84 km of lines, 5 – 10 years in service.

## 7.4 Design parameters

### 7.4.1 Design codes

The following design codes have been used by respondents:



**Table 18** Survey results on design codes used

Design code	Operators	Designers
DNV RP B401 (pre 1993)	1	-
DNV RP B401 (1993)	-	2
DNV RP B401 (2005)	-	6
NACE (pre 1993)	1	5
DNV RP F103	-	7
NORSOK M503	-	4
In house (own)	2	1
In house (client specified)	-	2

Only one operator reported doing CP designs in-house, another required an external designer to use the operator's in-house codes. All three operators used external design houses for CP systems. Where responses indicate deviations from the codes, three derive the values used from experience and/or field testing, one from laboratory data and two 'add safety margins'.

#### 7.4.2 Protection potentials

Only three respondents stated the range of protection potentials used for design, the three ranges being:

-800 to -1100 mV  
-825 to -1100 mV  
-900 to -3000 mV

It may be noted that the last of these can only be achieved by an impressed current system, and is more appropriate to onshore lines.

#### 7.4.3 Protection current densities

Three respondents indicated that they use design current densities differing from those in the design codes. Values used were:

Respondent 1: Greater than the values in DNV RP F103 at all depths

Respondent 2: 50 mA/m<sup>2</sup> (bare steel): 10 mA/m<sup>2</sup> (coated steel)

Respondent 3: See following Table

**Table 18** Survey results of protection current densities used for CP design from one respondent

	Water Depth (m)					Seabed
	0 - 20	21 - 100	101 - 300	301 - 1000	> 1000	
Initial	100	110	144	193	197	20
Average	44	54	66	82	83	20
Final	58	72	84	84	84	20

One respondent reported using 100 mA/m<sup>2</sup> for thermal sprayed metal coatings, an order of magnitude higher than the code recommendations. Another stated that:

‘Although it’s a good coating TSA is not figured into our calculations, in fact we assume that TSA will sacrificially give itself up and dissolve away leaving bear (sic) metal behind that either must be reapplied or have additional anodes electrically connected somewhere to deal with the eventual bear (sic) metal.’

#### 7.4.4 Coating breakdown

Again three respondents indicated deviations from the design codes. One reported using breakdown values ‘greater than F103’, while two provided the following tabulated data:

**Table 19** Survey results on coating breakdown factors used by two respondents

Coating system	Coating breakdown (%)	
	Initial	Annual rate
Organic (epoxy)	0.02	0.002
Organic + concrete	-	-
Glass flake	0.04	0.008
Glass flake + concrete	-	-
Polyethylene	0.01	0.001
Polypropylene	0.01	0.001
Thermal insulation	0.01	0.001

#### 7.4.5 Anode parameters

Only one respondent indicated a variation to the anode parameters proposed in the design codes. They state:

*‘We reduce anode efficiency by 50% for anodes working in water above 65 C. Ideally, for hot subsea hardware, we keep anodes mounted on exterior framing and insulate hot equipment where ever possible to minimize this problem.’*

It is worth noting that this response is of more relevance to pipework on well-heads and manifolds than to pipelines per se. The same respondent also answered, in some detail, the questions on design criteria, interaction and metallurgical constraints in the context of manifold and well-head design. His responses are not, therefore, reported further here.

#### 7.4.6 HISC susceptible materials

Two responses mentioned actions taken in respect of materials susceptible to HISC under the influence of CP. These were:

*‘We tend to specify thicker coatings and more strict criteria for holiday detection for HISC susceptible materials. Anodes are kept as far away as practicable to prevent over protection’*

*‘For duplex (stainless steels) – avoid using in highly stressed duty where possible; do not attach anodes directly.’*

*‘For high-tensile steel – provide only limited continuity where possible; we also specify maximum hardness to bolts to be 305 HV.’*

*'For SDSS (super duplex stainless steel), the newly published guidance in (DNV) RP F112 would be followed, but at the time of writing, no CP designs have been carried under these new guidelines.'*

*'Boundary element modelling may be performed depending on the deemed risk. CP calculations shall take into account the interactive effects of multiple CP systems.'*

## **7.5 System failures**

Given the limited number of operators responding, and the lack of reported failures in the literature, the range of causes of CP failure experienced is surprising. One case each is reported of:

- Poor CP design
- Failure on installation
- Anode passivity
- Failure of field joints
- Third party damage.

However, no failure attributed to the pipeline coating per se is reported. With the exception of third party damage, all the reported failure modes can be regarded as failures of QA/QC procedures.

Presumably as a result of these failures, two operators report the need for retrofitting of anode sleds by divers. One sled retrofit system has been installed using an ROV.

## **7.6 Additional responses**

The final question in the survey asked 'Do you have any other comments to make regarding your experience of design and/or operation of pipeline and flowline CP systems that are not covered elsewhere....'. Three comments were received:

*'Standardisation of CP design parameters further would be beneficial for the industry in order to regulate the many different designs that Companies produce. In particular, coating breakdown figures should be standardised.'*

*'A realistic design requirement for anodes is not always the driving force in CP design as anodes are very cheap compared to mobilisation of a vessel. This is fine for carbon steel but in regard to CRA materials designs are difficult to optimise in regard to potentials applied. Some thought regarding best practice would be highly beneficial as current guidelines still seem to lack certainty.'*

*'There are ongoing differences of opinion between operators on the requirement for isolation between pipeline, topsides and jacket CP systems. Some operators insist if there is an impressed current interface.'*

# **8 Summary of Risks to the Integrity of Subsea Pipelines and Flowlines Related to Coatings and Cathodic Protection**

## **8.1 General**

The external integrity of subsea pipeline and flowline systems related to coatings and cathodic protection consists broadly of two areas; aging of existing systems and new designs in future developments. In existing systems, breakdown of the coating and depletion of the anodes with time are the main concerns. Degradation of both systems may eventually lead to external corrosion of the pipeline or flowline.

In new systems, changes in CP design, often in conjunction with the use of high integrity multilayer coatings and the use of new materials or combinations of material, could pose

potential risks, in particular if either the design and/or installation were not carried out correctly. As highlighted in Section 6, even designs made according to existing standards could result in unforeseen failures by a combination of factors, in which, the coating and CP could be partly responsible.

## **8.2 Aging of coatings and cathodic protection systems**

Published data on the long term performance of subsea pipeline and flowline coatings under cathodic protection are sparse (see Section 5.5). This lack of data makes the assessment of the risk of external corrosion on the integrity of the pipeline and flowline in service difficult.

If the concern is with the degradation of just the coating system, included in various CP standards (DNV RP B401, DNV RP BF103 and ISO 15589-2) are tables which provide coating breakdown factors for various coating and field joint systems. Although the coating breakdown factors are primarily intended for use in CP design calculations; nevertheless, they must reflect some measure of the physical degradation of the various coating systems. If this information is used to calculate the current demand through the life of the new pipeline they may also be use, in a limited way, to highlight the relative degradation behaviour of pipelines already in service. Indeed these values have been suggested to be: *“rough estimated based on practical experience and engineering judgement”* (DNV RP F103). Based on this Tables 6, 7 and 8 can be used to provide a relative index of the rate of coating degradation in the type of coatings listed.

However, before this approach can be recommended there are a number of issues about the proposed values that may need to be clarified. Firstly, the differences between the coating breakdown factors presented in different standards have already been discussed in detail (See section 3.4.3-3.4.5 and 5.5). Also little is known of the data which the tabulated coating degradation factors are based on and degree of conservatism and hence their accuracy.

Pipeline corrosion protection is also reliant on the CP system; monitoring the potential and, where possible, the current output of the anode system ensures adequate protection of the pipeline. In a well-designed CP system any degradation of coating should be accounted and allowed for in the capacity of the CP system. The CP system design may also allow extra conservatism by including features to facilitate a retrofit of anode when necessary.

In most cases the assessment of the pipeline and flowline are carried out indirectly or, where possible, visually. Visually examination is often not possible or feasible as many pipes are buried and may not provide information on the degree of loss in protection provided by the coating.

Indirectly, it is based on surveys conducted on the CP system, where it is assumed if the pipeline potentials are operating within designed parameters, the coating has not degraded significantly and/or the anodes are adequately protecting any coating defects. Since recoating a subsea pipeline or flowline is not an easy process, when the pipeline potentials are found to be below the design protection potentials for whatever reason, a retrofit of the CP system is often the only option (see Section 4.8). Up to date, there is no evidence to suggest that this approach is not adequate in ensuring the integrity of carbon steel subsea pipelines. Where failures have occurred these have involved 13C%Cr and duplex stainless steel flowlines where the issues have been related to HISC and not general corrosion (see Section 6).

## **8.3 New designs and future trends**

### **8.3.1 Introduction**

In recent years the trend is for new offshore development to move to deeper water environments. This has led to the use of new materials and/or combinations of materials. This has sometimes resulted in unforeseen failures of CRA flowlines (see Section 6) when

use in conjunction with high integrity coatings and CP systems designed primarily to protect carbon steel. Although lessons learnt from the failures have resulted in the modification of CP design standards, a number of issues have been highlighted throughout the text related to trends in coating and CP design which may have an impact on the integrity of new developments involving subsea pipelines and flowlines.

### **8.3.2 Codes and standards**

Until recently, an accepted feature of international CP codes and standards has been their conservatism, largely prompted by a lack of reliable data on protection current densities and, particularly, coating breakdown rates. This has led to the provision of very robust CP systems capable of outlasting the operating lives of the pipelines themselves. Since CP costs are usually a very small fraction of the overall project costs this has been an acceptable compromise.

The robustness of most currently installed CP systems is reflected in their performance, with very few reported problems. Where problems have occurred, for example with field joints, the CP system usually has sufficient capacity to provide the additional current demand while still achieving the required life.

With the release of the latest revisions to the DNV, ISO and NORSOK standards, this situation has now fundamentally changed. A large measure of the conservatism, particularly in respect of coating breakdown, has been removed, and significant reliance is placed on achieving high standards of coating application. In ISO this even extends to field joints, where the assumption is made that they will have '*...a quality equivalent to the factory applied coatings*'. Given the historic problems associated with producing consistent field joint coatings offshore, this seems an unduly optimistic approach. Until systems designed to the new criteria have been in service, it is not clear whether this approach is practical. At least one of the respondents in the survey intends to continue to use parameters more conservative than the new codes.

Although there is no automatic schedule for revision and updating of the DNV and NORSOK standards, the next revision to the ISO standard is due in 2009.

### **8.3.3 Coatings**

The trend toward high performance coating systems can be expected to continue, with more use of 3-layer systems, particularly in deep water. A greater emphasis will need to be placed on ensuring that field joint coatings are applied to a similar standard to the coating on the majority of the pipeline.

### **8.3.4 Anode distribution**

The move to high integrity coatings, and the removal of conservatism from the design codes, now allows the use of pipeline anodes at much wider spacing than hitherto. The use of anodes directly attached to lines with thermal insulation can be avoided, instead using anodes mounted on structures at the ends of lines, for very long lines, installed as anode spools or cable attached anode sleds<sup>74,75</sup>.

This approach is likely to find favour as more 'hot' product streams are exploited and as a means of cost reduction. However, it must be realised that the attenuation equations used to calculate, and sometimes to justify, wide anode spacing rely on knowing the conductance of the coatings used. While estimates of conductance for new coatings could be obtained (although no data appear to be presently available in the public domain), values for coatings after some years in service can only be guessed.

Until service experience of such wide spaced anodes becomes available, there must be some doubt as to the accuracy of this approach. Research focussed on determining conductance on new and aged coatings, together with actual measurement of attenuation on in-situ pipelines would be invaluable.

### **8.3.5 Pipeline materials**

The protection of carbon and low alloy steel pipelines is well established and requires no special precautions in respect of the use of sacrificial anode cathodic protection. The situation is different with CRAs, often now required to handle corrosive product streams, which may be susceptible to HISC. Where stress levels are uncertain it may be necessary to control potentials produced by the CP system to values less negative than those in a conventional system. This is relatively straightforward for pipelines considered as stand alone components, but becomes more complex when they are associated with structures constructed all, or in part, from carbon steels.

Three methods have found, limited, use for such potential control. The use of 'remote' anode sleds or spools is subject to the same caveats as those discussed in section 7.3 above. Low driving potential aluminium gallium alloy anodes are relatively unproven and would require close spacing along the pipe for successful protection when carbon steel is present. Schottky barrier rectifiers have been used on a number of pipelines; they require careful attention to design.

As with coating conductance, the question of effective potential control would benefit from a detailed research programme.

### **8.3.6 Deep waters**

Moves to production in ever deeper waters require a better knowledge of the effects of depth on calcareous scale formation, and the consequent current densities needed for protection. While a number of studies, both in-service and laboratory, have addressed this problem, further work is required.

### **8.3.7 Surveying and monitoring**

All the developments described above mandate an accurate knowledge of the CP protection potentials actually achieved once the pipeline is installed. Unless used on relatively shallow (<200 m) unburied pipelines, presently available survey methods have severe limitations. Further development is needed in this area.