

DEP SPECIFICATION

CARBON STEEL CORROSION ENGINEERING MANUAL FOR UPSTREAM FACILITIES

DEP 30.10.02.14-Gen.

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(DEP Circular 28/11 has been incorporated)

(DEP Circular 02/12 has been incorporated)

DESIGN AND ENGINEERING PRACTICE

DEM1



PREFACE

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1. INTRODUCTION

1.1 SCOPE

This new DEP specifies the requirements for corrosion control of carbon steel in Upstream facilities, including downhole, surface, plant, and pipelines, as detailed in Appendix C.

The scope of this document is limited to:

- **Process oil and gas streams**, i.e., streams combining gas, oil, condensate, water, and/or treatment chemicals. Single phase water, methanol, and/or glycol systems are outside of the scope of the current document; these types of systems require different corrosion control models and can utilise different corrosion control options;
- **Non incipient failure mechanisms**. Incipient failure mechanisms (e.g. sulphide stress corrosion cracking, brittle fracture) should be addressed by materials selection or in some cases by process control;
- **Internal corrosion of carbon steel**. External corrosion is generally not an issue in corrosion management of carbon steel piping or tubulars, because the external issues can all be mitigated by applying the proper coating and adequate cathodic protection (though there are special considerations in the design and operation of high temperature lines).

Equipment items to be included and excluded from the scope are summarised in Appendix C.

This DEP is closely linked to 5 other DEPs:

DEP 39.01.10.11-Gen.	Selection of materials for life cycle performance (Upstream Facilities) - Materials selection process
DEP 39.01.10 12-Gen.	Selection of materials for life cycle performance (Upstream Facilities) - Equipment
DEP 30.10.02.15-Gen.	Materials for use in H ₂ S environments (amendments/supplements to ISO 15156:2009)
DEP 31.01.10.10-Gen.	Chemical Injection Systems

but does not duplicate their content.

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

1.1.1 Scope Background

The purpose of this document is to ensure that all relevant corrosion management issues associated with the use of carbon steel in a corrosive service in Upstream facilities are adequately addressed at each stage of the business cycle. The majority of Upstream projects select carbon steel with some form of corrosion control as it is the most cost effective AND technically accepted design option; hence making carbon steel the common base case for many developments. The purpose of this DEP is therefore to facilitate the selection and use of carbon steel in a consistent manner throughout the Shell Group of Upstream Operating Companies.

Given that carbon steel is the base case reference material; all approaches must be exhausted to ensure that this option is properly and safely assessed. The assessment of the feasibility of carbon steel should establish the corrosion management requirements within the overall integrity management of the facilities, in order to prevent unacceptable risk of failure or loss of operability from corrosion. Once selected, the system has to be correctly designed, installed, commissioned and managed during the whole operation life time.

It is important that the constraints applied by the materials and corrosion engineer at the design stage are fully appreciated by staff involved in operating an installation. The use of corrosion monitoring and inspection data in the day-to-day operation of equipment should be maximized in indicating where future designs could be improved.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

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

This DEP is intended for use in facilities related to oil and gas production and gas handling.

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

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

1.3 DEFINITIONS

1.3.1 General definitions

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

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

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

The word **shall** indicates a requirement.

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

The word **should** indicates a recommendation.

1.3.2 Specific definitions

Term	Definition
Corrosion Allowance	The additional wall thickness that is provided to compensate for the expected loss of wall thickness due to corrosion under the intended operating conditions. This is used for both the total estimated wall thickness reduction of carbon steel in service (also called the Service Life Corrosion) and the design (installed) corrosion allowance, which may be higher than the estimated wall thickness in service for a variety of reasons.
Corrosion System or sub-System	Grouping of tubulars, piping, pipelines, vessels, tanks and equipment that have the same corrosion risks and hence the same generic inspection requirements. Corrosion systems are also called corrosion circuits or corrosion loops .

Term	Definition
General Corrosion	The loss of wall thickness progressing at approximately the same rate over much of the surface of the metal component in question. It affects more than 10 % of the surface area and the variation in loss in wall thickness is less than 1.3 mm (50 mils).
Localised Corrosion	The loss of wall thickness at discrete sites. It affects less than 10 % of the surface area or the loss of wall thickness shows variations of more than 1.3 mm (50 mils). It should be noted that localised corrosion is not principally different from general corrosion. Localised corrosion is the result of locally different degradation conditions, e.g., pH, liquid velocity, etc.
Pitting	Extremely localised wall thinning. There is little consensus in the industry as to a strict quantitative definition of pitting. Most definitions imply that the depth of attack exceeds the width.
Pipeline	A system of pipes and other components used for the transportation of fluids, between (but excluding) facilities. A pipeline extends from pig trap to pig trap (including the pig traps), or, if no pig trap is fitted, to the first isolation valve within the plant boundaries or a more inward valve if so nominated. The terms flowlines, trunklines, in-field lines, gathering lines, delivery lines may be used for the pipeline.

1.3.3 Abbreviations

CA	Corrosion Allowance (also called Service Life Corrosion), (mm)
CI	(Continuous Injected) Corrosion Inhibitor (as opposed to Batch injected corrosion inhibitor)
CR	Overall Corrosion Rate per Year, (mm/y)
CMF	Corrosion Management Framework
CMM	Corrosion Management Manual
CR _i	Inhibited Corrosion Rate, (mm/y)
CR _u	Uninhibited Corrosion Rate, (mm/y)
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
ER	Electrical Resistance probe
f	Inhibitor System Availability, expressed as the Fraction of the time that the inhibitor system is available
FFS	Fitness for Service
FMEA	Failure Modes and Effect Analysis of the Corrosion Control System
KPI	Key Performance Indicator
MIC	Microbiologically Induced Corrosion

NDE	Non Destructive Examination
NPV	Net Present Value
RBA	Risk Based Assessment, includes RBI, corrosion assessment, integrity assessment, remaining life prediction and improvement recommendations
RBI	Risk Based Inspection
S-RBI	Shell Risk Based Inspection:
SRB	Sulphate Reducing Bacteria
THPS	Tetrakis Hydroxymethyl Phosphonium Sulphate – a biocide

1.4 CROSS-REFERENCES

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

The materials, corrosion and inspection deliverables required at each stage of the project cycle are identified in each section of the document.

1.5 COMMENTS ON THIS DEP

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

1.6 DUAL UNITS

**Amended per
Circular 02/12**

Dual units have been incorporated throughout this DEP.

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

2. CORROSION CONTROL SYSTEM SELECTION PROCESS

2.1 ASSESS DOMINANT CORROSION MECHANISM: BASIS OF THE H₂S AND CO₂ RATIO

The modelling approaches covered in this document are applicable to all types of corrosion environments. If the system is subject to CO₂ corrosion, mixed corrosion, or sour corrosion (see classification below), this DEP covers the corrosion control requirements.

The first step in the assessment is to determine:

1. if the system is sweet or sour
2. the dominant corrosion mechanism.

This assessment shall be made in the Corrosion Control Option Selection Report, which is produced as part of the Feasibility Report in the assess phase of the project.

The operating window and the associated alarm point(s) SHALL [PS] be established and documented to trigger reassessment of the corrosion mechanism if changes in the operating conditions occur outside the defined operating window.

This initial assessment SHALL [PS] also determine the alarm point for re-assessment and whether this is likely to occur, e.g., initial data of poor quality, reservoir souring potential, new facilities being tied in.

CO₂/H₂S corrosion shall be categorised into one of three regimes:

- When $p\text{CO}_2/p\text{H}_2\text{S} > 5000$: CO₂ corrosion alone. The corrosion rates shall be predicted using the HYDROCOR corrosion model, if the conditions are within the operating window of the model (2.2.2).
- When $p\text{CO}_2/p\text{H}_2\text{S}$ is between 20 and 5000: Mixed corrosion regime, i.e. corrosion in slightly sour environments. There will be localised corrosion, but this has an upper limit of the predicted CO₂ corrosion rate. It is most likely that the localised corrosion rate will be considerably lower than the predicted corrosion rate, due to protection by scales. However, any mitigation shall be the subject of project-specific corrosion testing if benefits from H₂S are to be adopted.
- $p\text{CO}_2/p\text{H}_2\text{S} < 20$: H₂S corrosion dominates. Corrosion rate is governed by the protectivity of the corrosion scales. There are possibly localised corrosion risks in the event of breakdown of the protective sulphide scales.

The alarm point for re-assessment will be the lowest of the " $p\text{CO}_2/p\text{H}_2\text{S} < 20$ " limit and the DEP 30.10.02.15 limit for sour service. This data shall be copied into the Corrosion Management Framework and will be carried through to operations as a live document.

During the select phase, define phase and during operations, any increased levels of H₂S (relative to CO₂ levels) SHALL [PS] be re-assessed against the alarm points initially determined. The alarm point also becomes one of the Key Performance Indicators for the system (3.2.1).

If the H₂S level does go above the alarm point, a full project materials and corrosion re-assessment SHALL [PS] be carried out.

2.2 DETERMINE UNINHIBITED CORROSION UNDER FLOWING CONDITIONS

2.2.1 Corrosivity Assessment Approaches

Uninhibited corrosion under flowing conditions, CR_u, SHALL [PS] be determined from a choice of:

1. Simplified corrosion modelling using CORRAT (which is part of the overall HYDROCOR model). This is the most appropriate tool during the assess and select phase, because of the lack of input data available, which required for more detailed corrosion models.
2. Detailed corrosion modelling, using HYDROCOR. This route would be taken if CORRAT gave results that resulted in a high corrosion allowance and adequate

data is available to run HYDROCOR. For pipelines HYDROCOR shall be used when adequate data becomes available, in order to optimise the corrosion allowance requirements (i.e. from the select phase onwards). In most cases for piping, CORRAT is adequate and there is less incentive to optimise the corrosion allowance, as piping corrosion allowances (in the piping classes) are standard 0 mm (0 mils), 1 mm (40 mils), or 3 mm (120 mils).

3. Corrosion modelling based on laboratory test data (2.6). Laboratory test data are needed to assess uninhibited corrosion rates where conditions are outside of the application limits of the models above.

Note that field experience data cannot directly give an uninhibited corrosion rate (2.7), but can be used in the overall analysis to assess sensitivities.

2.2.2 Operating Envelope for the Corrosion Models

Two different corrosion models can be used in determining the corrosion rates, depending on the level of data that is available. When to use each model is discussed in section (2.2.1). Both models use the same core equations and have the same proven range of application. In the event a case falls outside the indicated application limits, baseline corrosion rates shall be approved by the Principal.

Table 1: HYDROCOR and CORRAT applications and limits.

Parameter	HYDROCOR and CORRAT
pCO ₂ , bar (psi)	0.05 – 20 (0.73 – 300)
Temperature, °C (°F)	4 –150 (40 – 300)
Pressure, bar (psi)	1 – 200 (15 – 2900)
Production fluids/volumes	gas, NGL, oil
pCO ₂ /pH ₂ S ratio	Whole range
Corrosion mechanisms considered	• CO₂ corrosion in flowing conditions • CO₂ corrosion in stagnant/low flow conditions • CO₂/H₂S corrosion • organic acid corrosion • wet oxygen corrosion (operations specific) • microbiologically induced corrosion (operations specific)

2.3 SELECTION OF POSSIBLE CORROSION CONTROL OPTIONS

2.3.1 Types of Service and Potential Failure Modes

Production systems shall be initially grouped into (internal) high level corrosion systems by the prevailing type of service.

Table 2: Corrosion Systems for Production Systems

System Description		
Preferred name	Common/alternative name	Main Phases present
Wet Multiphase Gas	Gas flowline	Gas, Water, Condensate
Wet Gas	Wet Separated Gas	Gas, Water
Dry Gas	-	Gas
Dry Gas/Condensate	-	Gas, Condensate
Wet Multiphase Oil	Oil flowline	Gas, Water, Oil
Wet Oil	Stabilised Oil/Water	Oil, Water, possible low levels of gas
Wet Condensate	Stabilised Condensate/Water	Condensate, Water, possible low levels of gas
Dry Oil	Dry Stabilised Oil	Oil
Dry Condensate	Dry Stabilised Condensate	Condensate

For new systems this classification shall initially be carried out in the assess phase; for any existing systems (already in operations) this should be one of the first steps in the assessment process.

It is used to identify the type of corrosion monitoring and for pipelines the pigging regime (if any) required for corrosion control. These systems are later used in Risk Based Assessment analysis (3.3).

For each of the defined corrosion systems, failure modes have been assigned based on a review of the corrosion risks of that environment and discussions with the operations personnel (Appendix A).

In summary, the internal corrosion or erosion failure modes that routinely need to be considered in looking at a potential loss of containment are:

- general corrosion
- localised corrosion
- erosion due to fluid flow
- erosion due to sand

The erosion issues shall be as covered in DEP 39.01.10.11-Gen.

There are other non-corrosion or erosion failure modes that could result in a loss of containment, e.g., leaking seals and manufacturing defects. These are not considered further in this document as these can be avoided by good design and QC during the fabrication and installation stages.

Once the internal failure modes have been assessed, the corrosion control options may be selected.

2.3.2 Corrosion Control Options

2.3.2.1 Timing for Selection of Options

The corrosion control option shall be selected during the assess or the select phase of the project (there may be a short list of 2 or 3 options under consideration at the end of the assess phase). For the inhibited wet hydrocarbon design, the option selection is linked to the selection of the required corrosion allowance (2.5.3), the design of the inhibition system (2.11), and other sustainability factors such as consequences of failure and requirements to adequately process inhibited fluids.

2.3.2.2 Options

There are likely to be a number of technically acceptable corrosion control options for a given development. All technically acceptable cases shall be taken forward for economic evaluation (e.g. 3 options - carbon steel plus corrosion allowance plus inhibitor versus carbon steel with minimal corrosion allowance with TEG dehydration units versus CRA).

A case utilizing carbon steel should be presented as the base case. This may require a certain corrosion allowance and the use of inhibitor to control corrosion.

For pipelines, the cases presented shall include one or more of the first four options in Table 3.

For piping, the cases presented shall include one or more of the first six options in Table 4.

In Table 3 the maximum corrosion allowance considered for a carbon steel pipeline is 8 mm. This should be viewed as a trigger for further review, not a point at which carbon steel lines should be rejected; higher corrosion allowance may be feasible, depending on the corrosion morphology and the ability to demonstrate protection of the corroded pipe.

In Table 4 the maximum corrosion allowance considered for carbon steel piping and vessels is 3 mm (120 mils). With topside piping and onshore piping there is also the option to change the piping out during the project lifetime. If this is selected as a design option it shall be agreed with operations.

The main options are:

Table 3: Pipeline Corrosion Control Options

Required CA	Corrosion Control Option	Comments
0 mm (0 mils) with no corrosion control (non-corrosive systems)	CS with no or minimal CA Note: With no CA any internal or external corrosion upset may end further useful life cycle or entail performance restrictions or require a burdensome inspection approach.	To determine the required corrosion allowance (if any) an assessment shall be made of; - if the fluids could become corrosive - the risk of this occurring In oil or multiphase lines if corrosion control relies upon the velocities being high enough to keep all water entrained, the design shall also address the velocities required to re-entrain the water that will drop out during any interruptions to production. For dry gas lines consideration shall be given to liquid carry-over from the dehydration facility.
< 8 mm (320 mils) with no corrosion control	CS with required CA	Any internal corrosion that occurs has to be absorbed by the CA. Also consider the option of corrosion control and a reduced CA.
< 8 mm (320 mils) with corrosion control by inhibition, dehydration or pH stabilisation	CS with required CA plus inhibition system, dehydration or pH stabilisation.	For the systems requiring a high CA it may be necessary to optimise the required availability of the corrosion control system to reach an economically viable corrosion allowance (next option).
> 8 mm (320 mils) with corrosion control by inhibition, dehydration or pH stabilisation	Consider high availability inhibition systems dehydration or pH stabilisation, and coolers	The required CA with high availability corrosion control systems and/or coolers shall be < 8 mm (320 mils) for this to be an acceptable option. If this does not reduce the required CA to < 8 mm (320 mils) move on to the next level below.
> 8 mm (320 mils) with all possible corrosion control systems employed	Polymer/GRE CRA	CRA may be selected for the whole line or for part of the line to deal with specific problems (e.g. high temperature inlet section, high velocity sections etc.)

Table 4 Piping and Vessel Corrosion Control Options

Required CA	Corrosion Control Option	Comments
0 mm (0 mils) with no corrosion control (non-corrosive systems)	CS with no or minimal CA Note: With no CA any internal or external corrosion upset may end further useful life cycle or entail performance restrictions.	Select piping class with 0 mm (0 mils) CA. To determine the required corrosion allowance (if any), an assessment shall be made of; - if the fluids could become corrosive - the risk of this occurring In oil or multiphase lines if corrosion control relies upon the velocities being high enough to keep all water entrained, the design shall also address the velocities required to re-entrain the water that will drop out during any interruptions to production.
< 3 mm (120 mils) with no corrosion control	CS with required CA	Select 1 mm (40 mils) or 3 mm (120 mils) CA as appropriate and select the corresponding piping class. Any internal corrosion that occurs then has to be absorbed by the CA. Also consider the option of corrosion control and a reduced CA.
< 3 mm (120 mils) with corrosion control by inhibition ⁽¹⁾ , dehydration or pH stabilisation	CS with required CA plus inhibition system, dehydration or pH stabilisation.	Select 1 mm (40 mils) or 3 mm (120 mils) CA as appropriate and select the corresponding piping class.
3 mm < CA < 8 mm (120 mils < CA < 320 mils) corrosion control by inhibition ⁽¹⁾ , dehydration or pH stabilisation	CS with required CA plus inhibition system, dehydration or pH stabilisation.	Consider developing new piping class for corrosion allowance above 3 mm (120 mils).
> 3 mm (120 mils) with corrosion control by inhibition ⁽¹⁾ , dehydration or pH stabilisation	CS with 3 mm (120 mils) corrosion allowance (max of current piping classes) plus design for change out during life.	Assess how long the piping / vessels will last (less than the design life), factor costs of piping / vessel change out and increased inspection into the project economics.
> 8 mm (320 mils) with corrosion control by inhibition ⁽¹⁾ , dehydration or pH stabilisation	Consider high availability inhibition systems, dehydration or pH stabilisation and coolers	The required CA with high availability corrosion control systems and/or coolers shall be < 8 mm (320 mils) for this to be an acceptable option. If this does not reduce the required CA to < 8 mm (320 mils) move on to the next level below. If the required corrosion allowance is between 3 mm (120 mils) and 8 mm (320 mils) new piping classes would be required.
> 8 mm (320 mils) with all possible corrosion control systems employed	Polymer/GRE CRA	CRA may be selected for the whole line or for part of the line to deal with specific problems (e.g. high temperature inlet section, high velocity sections etc.)

Note 1 Vessels shall not to rely upon inhibition for corrosion control (2.5.2). In complex pipework, inhibition may be unreliable considering, e.g., the effects of turbulence, changes in flow regime, local turbulence, changes in flow rate, mixing length for inhibitor downstream of the injection point, inhibitor partitioning between different phases..

Dehydration options are covered by process/facilities design.

Solid non-metallic pipes and thermoplastic lines pipes are covered in;

- DEP 31.40.10.19-Gen
- DEP 30.10.02.13-Gen.

Corrosion Resistant Alloys (CRA) are covered in;

- DEP 39.01.10.11-Gen.
- DEP 39.01.10 12-Gen.
- DEP 30.10.02.15-Gen.

A special case to be considered for gas systems with only condensed water and no added formation or surface water is the addition of alcohol. This can give a reduction in the corrosion rate up to a factor of 10. This is only field proven for mildly corrosive systems (e.g. systems with 2 mm/y (80 mils/y) corrosion rate prior to alcohol addition). The required CA with alcohol addition for pipelines must be < 8 mm (320 mils) for this to be an acceptable option.

Another potential method of corrosion control is pH adjustment, e.g., by injection of amines, caustic or bicarbonate. pH control can be considered for the following types of developments:

- gas/condensate systems in which either glycol or methanol are used for hydrate prevention;
- no formation water is present;
- with the current limited knowledge, pH control should not be applied for sour conditions.
- the fall-back option of corrosion inhibition shall always be available (in case formation water is produced or if for any reason pH control cannot reduce corrosion to an acceptable level).

More details of pH control and other requirements of the approach are given in Appendix B.

2.4 SELECTION OF APPROPRIATE INHIBITED CORROSION RATE AND INHIBITOR SYSTEM AVAILABILITY

2.4.1 Relationship of Corrosion Allowance, Inhibitor Availability and Corrosion Rates

The required corrosion allowance and the inhibitor availability (or inhibitor system downtime) are linked, basis the inhibited and uninhibited corrosion rate. There are two possible design options:

Design Option 1	Design Option 2
• Choose or estimate an inhibitor availability • calculate the required corrosion allowance • review the corrosion allowance • go through this loop to optimise the system as required.	• Choose a corrosion allowance • calculate the required inhibitor availability • design an inhibition system to meet this availability.

Both options can lead to a technically acceptable design. Option 1 shall be followed for *new* facilities in Shell. For *existing* facilities the corrosion allowance is fixed, so the 2nd option is more applicable. Either option shall consider the impact of the identified CA on other

design factors, e.g., impact on flow and pressure drop, thermal stress loads and buckling, required buckling constraints such as pipeline cover.

The overall corrosion rate for an inhibited system shall first be calculated on the basis of the inhibitor availability principle:

$$CR = f \times CR_i + (1 - f) \times CR_u \quad \{1\}$$

where CR is the overall corrosion rate per year,

f is the fraction of time the inhibitor system is working i.e. availability,

CR_i the inhibited corrosion rate,

CR_u the predicted uninhibited corrosion rate.

For a system in operation, the actual and worst case predicted future inhibitor availability can be determined respectively from historical data and from a review of uninhibited events (3.4.2). In operations the actual inhibited corrosion rate should be measured. This data is used to determine the actual overall corrosion rate that is used in Risk Based Inspection assessment (4.2)

2.4.2 Inhibited Corrosion Rate, CR_i

The values to be used for inhibited corrosion rate in new designs are:

Table 5: Inhibited Corrosion Rates

Temperature Range, °C	Temperature Range, °F	Inhibited Corrosion Rate, CR _i , mm/y
Up to 120 °C	Up to 250 °C	0.1
> 120 °C and ≤150 °C	> 250 °C and ≤300 °C	0.2
Above 150 °C	Above 300 °C	Inhibition not recommended without specific testing

These values shall be set as the targets for the inhibitor testing programme. Should higher inhibited corrosion exist for the selected inhibitor, the higher values shall be incorporated into the design.

2.4.3 Inhibitor System Availability

The initial starting point for f shall be 0.95 (95 %). This value of f equates to 18 days inhibitor system downtime per year. This is achievable with a basic inhibition system (as illustrated below).

Using the same basic inhibition system, the value of f may need to be reduced if there are known specific operating difficulties in the location the pipeline will be installed (e.g. limited access, maintenance problems, taking account of comparable performance on existing systems etc.). This should be critically assessed in the assess and select design phases.

The value of f used in the design can be increased with the use of more automated systems, faster response monitoring, backup systems etc.

Detailed requirements for chemical availability (f = 0.95, 0.99, or >0.99) shall be required as identified in DEP 31.01.10.10-Gen. The choice of the inhibitor system has to consider a number of factors:

- For a particular operating location, the more sophisticated equipment required for high availabilities may be difficult to procure initially and it may be difficult to get spare parts for maintenance;

- Operating levels vary by location; in some locations it is a requirement to employ a large number of local staff, so automated systems may be impractical. In other locations the number of staff visiting a location has to be strictly limited (e.g. not normally manned platforms);
- Higher availability will link to lower required system corrosion allowance; an economic assessment of acceptable options may be required.

2.4.4 Review of Uninhibited Events

When the design relies on higher availability of the inhibitor system a more comprehensive review of the events that cause inhibitor system downtime is required. The following factors shall be considered in this assessment:

- t_1 Response time to detect the event (days)
- t_2 Response time to correct inhibitor ineffective event, once detected (days)
- t_3 Time between inhibitor start up and the first pigging run. This is only applicable if pigging is needed to distribute the inhibitor properly, or to remove corrosion products for inhibitor effectiveness,

The inhibitor unavailability shall be calculated accordingly:

$$1 - f = \frac{1}{365} \sum_1^n (t_1 + t_2 + t_3);$$

where this is the sum of each uninhibited event that occurs in a year (and there may be more than one different type of event).

2.5 DETERMINING THE REQUIRED CORROSION ALLOWANCE

The required corrosion allowance shall be determined in the select phase and refined in the define phase of the project. A final validation of the calculation input used in the define phase (e.g. based on new data or further analysis) shall be done just before the long lead items (like the linepipe) are ordered. Once the material (linepipe, piping, vessels etc.) has been ordered the corrosion allowance is fixed.

2.5.1 Including the Corrosion Allowance in the Overall Wall Thickness

The corrosion allowance shall be included in the overall thickness as described below:

For Pipelines

- The corrosion allowance, CA, shall be determined by an agreed procedure, (2.5.2) and this section.
- The wall thickness required for the design pressure and temperature, t_d shall be determined using an applicable design code e.g. ASME B31.4, B31.8 etc.
- The minimum design thickness shall be $t_d + CA$.
- Thicker pipes may be selected based on factors such as:
 - o Additional wall thickness required for laying stresses
 - o Wall thickness is rounded up to a standard (or available) pipe size
 - o For the cases above, it is important that the corrosion allowance is not added on top of these additional factors.

During the early part of the define phase the value of CA may be optimised by looking at the field life production profile (generally as pressures decrease the corrosivity decreases). If the system pressures will drop over time, t_d will reduce, and allowing the wall thickness to be used as part of the corrosion allowance. This requires a formal de-rating procedure for the line.

For Piping:

- The corrosion allowance, CA, shall be determined by an agreed procedure, (2.5.2) and this section. This CA is rounded up to the standard piping class values of 0 mm (0 mils), 1 mm (40 mils), or 3 mm (120 mils).
- The required piping class is selected based on:
 1. Required CA
 2. Service
 3. ANSI flange rating
- The actual CA on the piping will be equal to or thicker than the required CA because of factors such as:
 - o Design pressure of piping system is less than the ANSI flange rating selected
 - o In the piping class required wall thickness has been rounded up to a standard pipe size

For Vessels:

Inhibitors are not considered effective in pressure vessels. Where the service is corrosive, and corrosion inhibitors are provided to protect the pipeline and piping, the vessels shall be protected by CRA cladding or internal coatings.

Selection of CRA and limitations on use of internal coatings are covered in DEP 39.01.10.12-Gen.

Where the service is mildly corrosive (inhibitors not required), then a corrosion allowance may be applicable. There is more flexibility than for piping, but CA of 0, 1 or 3mm (0, 40, or 120 mils) tend to be used for carbon steel vessels.

2.5.2 Calculation of Corrosion Allowance

The corrosion allowance is first determined in the select phase ; it is calculated by multiplying the predicted corrosion rate by the design life:

$$CA = CR \times N \quad \{2\}$$

where CA = (lifetime) corrosion allowance in mm (mils),

CR = (average lifetime) predicted corrosion rate in mm/yr.(mils/yr),

N = design lifetime in years.

In the define phase, as a better field life production profile data becomes available, the value of the lifetime CA can be optimised by assessing the annual requirement for corrosion allowance as it changes through the field life. The HYDROCOR model can be used to run multiple cases e.g. one per year of operation using the varying operational profile, then the data summed to give a lifetime corrosion allowance requirement:

$$CA = \sum_{i=1}^N CA_i \quad \{3\}$$

where CA_i is the corrosion allowance required in the ith year of operation.

The corrosivity may change as the field declines due to change in flow rates. Reduction in flowrate usually leads to a reduction in corrosivity. However if the reduction in flowrate causes a change of flow regime, the corrosion behaviour of the system can change, with corrosion rates going up or down depending of the flow rate and the flow regime. If lower flow rates induce stratified flow, the uninhibited top-of-line corrosion rate shall be determined as input into the design CA. If new fields are tied into the existing facilities or depletion compression is added, the corrosivity can also change.

2.5.3 Corrosion Allowance Optimisation

For the wet hydrocarbon option, the corrosion allowance is optimised as the design process progresses and more information becomes available. Even at the end of the select phase there may still be some conservatism in the required corrosion allowance, because of some outstanding unknowns in the design.

The final opportunity to optimise the corrosion allowance occurs at the very beginning of the define phase, before the long lead items (like the linepipe) are ordered (probably within a few months of the beginning of the define phase).

The corrosion allowance generated shall be assessed against the following criteria:

- **Pipelines:** If CA is greater than 8 mm (320 mils) this should be a trigger point for a more detailed review.

In the define phase, carry out a preliminary pipeline RBA analysis (4.2) with the selected corrosion allowance and assess the inspection requirements. Determine if an increased corrosion allowance would result in zero or low inspection requirements and check if this is economically attractive.

- **Piping:** If CA is greater than 3 mm (120 mils) and less than 8 mm (320 mils), then carbon steel is still a possible option but new piping classes will have to be developed.

The corrosion allowance may have to be optimised when making an economic evaluation of carbon steel plus inhibition against the other corrosion control options. Depending on the constraints of the project, this should either be based on Life Cycle Costs or CAPEX.

If the required corrosion allowance calculated in the first pass does not meet these criteria, values of f and CR_i should be re-assessed, taking account of increased costs in some areas. Improving availability has been previously discussed (2.4.3). To use lower values for CR_i will require laboratory testing, or field experience from comparable operations to verify this case.

Two other options that can be considered are the impact of inhibitor persistency on the effective duration of the uninhibited event and the effect of shutting down production when there is an uninhibited event.

2.5.3.1 Impact of Inhibitor Persistency

The inhibitor persistency can have a beneficial effect, though it is unlikely that the persistency would be determined until inhibitor testing is carried out in the execute phase. Once an inhibitor has been selected the persistency of the inhibitor can be assessed.

The persistency has the effect of reducing the total *effective* inhibitor system downtime in an uninhibited event. The persistency depends upon the;

1. type of inhibitor
2. operating conditions.

2.5.3.2 Effect of Shutting Down Production

For highly corrosive conditions, the design option should consider designing to shut down production if there is an unacceptable uninhibited event. This is not a desirable design option, and would only be considered if there were no acceptable alternative approach. Examples are very corrosive systems (e.g. those with high uninhibited corrosion rates) and/or for long uninhibited events.

If this option has to be considered as part of the corrosion inhibition system, this shall be agreed up front with operations and clearly documented as there is a risk that when the event actually occurs operations may not want to shut down the facilities because of the impact on production revenues.

The risks of operating outside of the design need to be clearly defined and understood by all. From an economic standpoint this could be a very poor option as the cost of deferred

production is usually so high that extra safeguards for the inhibition system can be justified (e.g. duplicate pumps, low flow alarms, on-line corrosion monitoring etc.).

2.6 INHIBITOR LABORATORY TESTING, SELECTION & CONTRACTUAL ISSUES

2.6.1 Inhibitor Selection

Where inhibitor testing is required, this shall be carried out in accordance with a test protocol approved by the Principal.

Laboratory tests shall be carried out to assess inhibitor performance where the following conditions / requirements exist:

- a) To validate corrosion inhibition approach and availability; inhibited corrosion rates could be lower (or higher) than the default values (2.4.2).
- b) To assess the impact of known formation water on protective scales and on inhibitor performance (only possible before start up if there is adequate data available on the formation water).
- c) Normally inhibitors are suitable for mixed flow velocities up to 20 m/s (65 ft/s). If the fluid velocities are greater than this, the inhibitors shall be specifically tested under the highest anticipated system shear case, (e.g. risers). However, it is recommended to always test the inhibitor under the highest anticipated shear case.
- d) To see whether lower corrosion rates occur in wet oil systems, where the oil itself may act as an inhibitor. As this requires actual field oil samples this is only possible where the reservoirs being produced are known and already in production elsewhere in the field, or where sufficient good quality oil samples were collected during (extended) well tests.
- e) In low velocity systems (< 1.5 m/s [5 ft/s]) to assess whether a free water phase will occur (same comment as previous point).
- f) To see whether lower corrosion rates can be obtained in high temperature system or systems contain moderate levels of hydrogen sulphide, due to protection by corrosion product scales. If this route is followed, then careful assessment and testing is required to determine the conditions under which the scales are unstable, so that the operating window for the inhibited system utilising protective scales is well defined.
- g) To evaluate persistency when high availability inhibitor injection systems are specified.
- h) To assess effect on formation of oil in water where water treatment effects are a concern
- i) When compatibility with recommended materials is a concern or mixing with other treatment chemicals may occur before injection
- j) When inhibited corrosion rates for range of different dosages above and below target are desired to optimize injection program, life cycle, or address availability upsets in high availability systems.

Both blank and inhibited rates shall be measured. Laboratory experiments have to be carried out with control of at least the following parameters: pCO₂, pH₂S, T, pH, flow velocity, water cut, iron level, and water composition (bicarbonates). This highlights the need for timely, reliable data of expected operating conditions.

The companies selected to supply inhibitors shall be on the approved vendor list of the OU.

Inhibitor testing shall start at a sufficient time before commissioning, to allow time for the testing work and time to deliver the finally selected product to site before the commissioning. This could be up to 27 months beforehand.

The inhibitor system shall be started up during commissioning to check it is fully functional. This also applies to systems that do not require inhibition at day 1. This is discussed in

more detail in (2.12.1). Contacting/partnering issues may require an even earlier start of the inhibitor selection work to determine which contractors have acceptable products (2.6.3).

The full inhibitor selection programme shall include:

- Determination of the maximum operating window to determine the inhibitor test conditions.
- Set acceptance criteria for the inhibitors. A typical set of criteria would include:
 - o No localised corrosion at the operating window specified. This SHALL [PS] include testing on actual pipeline welds, which requires actual linepipe samples fabricated using weld procedures from the selected pipe lay contractor. All proposed weld chemistries shall be adequately covered (e.g., mainline, double-jointing, root repairs)
 - o Inhibited general corrosion rate of less than xx mm/y (select 0.1 or 0.2) at the operating window specified.
 - o Maximum required inhibitor concentration of less than xxx ppm (typically 100 ppm or 200 ppm, but depends on the design of the inhibitor system (mainly pumps and storage tanks)).
 - o Test compatibility with other chemicals in the system (e.g. scale inhibitors, biocides, hydrate inhibitors, wax inhibitors, demulsifiers); no reduction in inhibitor performance. State concentrations of other chemicals in the system.
 - o Required environmental discharge classification for chemicals used
- Assessment of volumes of chemicals that will be required in operation, the initial supply requirement for commissioning the system and the routine requirements in operations (initial tank fill is considered part of Capex costs, subsequent fills are Opex costs). Communicate volume requirements to project Capex and Opex cost estimation group.
- Invitation to vendors to supply inhibitor samples (usually 1 or 2 per vendor) to meet the required operating window. The vendor list shall be developed with the OU, based on their list of approved vendors. The invitation usually includes requirements for commercial bids as well, though this will be handled separately from the technical assessment. The commercial data shall be fixed prior to the completion of the technical test programme.

Both blank and inhibited rates need to be measured. If the blank corrosion rates on welded samples reveal preferential weld corrosion this shall be immediately reported as this could require a change in weld procedure.

The deliverables from the test programme are the successful product names, required (start up) injection rates/concentration, and data to evaluate availability upsets, e.g., persistency, CR versus under dosage..

2.6.2 Environmental Issues

The evaluation of the environmental aspects of corrosion inhibition is a three-tier process, which involves government regulations, Shell policy and operating unit policy.

2.6.2.1 Government Regulations

The applicable government regulations shall be followed.

2.6.2.2 Shell Policy

Shell Policy for discharging of waste waters to the environment are detailed in the HSSE Control Framework Environmental Manual.

2.6.2.3 Operating unit policy

Many operating units operate in countries that do not have environmental regulations. In case of doubt it is required that the responsible Technical Authority for environmental issues be contacted for governance.

2.6.3 Contracting/Partnering with the Selected Chemical Supplier

In the execute phase, after the successful inhibitors have been identified, further technical and contractual discussions with the successful inhibitor companies shall be carried out .

In operations the operating company may have a standard contracting strategy that defines contract lengths and contract review periods. To change inhibitors would require a full inhibitor selection programme .

2.7 USING ANALOGOUS DATA FROM SIMILAR FIELDS

For the design, process data on uninhibited and inhibited corrosion rates are needed. Field experience provides little information about uninhibited corrosion rates, because aggressive corrosion conditions are typically controlled, e.g., by inhibition.

Field experience data are useful in the select design phase in assessing the technical risks involved i.e. are the conditions well within the bounds of successful inhibitor operation or are they at the limits of the area of known experience.

2.8 ECONOMIC ANALYSIS AND LIFE CYCLE COSTS

The economic incentive of a carbon steel production systems shall be evaluated for each specific project, as the CAPEX of CRAs and carbon steel can vary widely, depending on external factors and project conditions. For onshore piping and offshore process systems, if carbon steel is considered for use for the upstream pipeline (or sometimes the downstream pipeline), then carbon steel plus inhibition should also be considered for the plant piping, where it is suitable.

2.8.1 CAPEX Constrained Projects

Some projects are CAPEX constrained, and the project guidelines are to assess the option selection on CAPEX issues only. However, unless otherwise stated by the project team, economic analysis shall be carried out on a life cycle cost basis. When considering CAPEX issues only, the OU M&C TA1 shall be informed.

2.8.2 Life Cycle Cost Minimisation

2.9 IMPACT OF CORROSION CONTROL SYSTEM ON OTHER AREAS OF THE DESIGN

The use of carbon steel with a corrosion control system introduces other types of risk, related to the operability of the line and the effect of the corrosion control method on downstream processing of hydrocarbons and water, which need to be assessed in the select phase and the define phase . The following shall be included in the assessment:

- a) Environmental issues relating to inhibitor use including overboard disposal of produced water and the ultimate point of disposal of the inhibitor.
- b) Corrosion inhibitor may have an impact on downstream facilities.

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- c) Corrosion inhibitors may be corrosive, neat, to carbon steel. Delivery, injection, and mixing into flow SHALL [PS] shall be considered in the design to address this issue.
- d) The handling or impact of solids created by corrosion
- e) The production system SHALL [PS] be designed to exclude oxygen entry. In production systems, oxygen shall be controlled to be less than 20 ppb in the water phase. Operational discipline to avoid ingress of oxygen is essential to prevent corrosion. Individual projects may set tighter criteria than this, depending on where the measurement is taken and the risk of oxygen entry downstream of this.

- f) The production system SHALL [PS] be designed to avoid or minimize contamination of the system with bacteria, provide for bacterial control, and monitor bacterial contamination. If water is injected into the facilities the water shall be treated with biocide (and possibly with oxygen scavenger) and filtered to avoid deposits. Because of the risk of contamination, if water is injected into the facilities the systems shall be designed for regular batch treatment with biocides.
- g) Once a system is contaminated with bacteria, it is virtually impossible to eradicate them completely and the threat of corrosion has to be managed. This shall be done by means of regular batch treatments of biocides. The frequency and concentration should be optimised based on monitoring results but a proven initial default treatment strategy is a 300 ppm(v) treatment of the water phase during a 2 hour period every two weeks with THPS, if this is environmentally acceptable. If treatment is carried out continuously over a long period of time, the biocide in use may not control the bacteria population and alternative products or higher dosage will be required. The assessment of the effectiveness of the biocide shall be done at least once a year, or more often if surveillance data indicates loss of control..

This further supports the design philosophy that all pipelines shall be designed to be piggable. Batch inhibitor treatments shall be launched in a pigging train (a pig ahead and behind the chemical slug), unless it can be demonstrated that the chemical will achieve the required contact time on all pipeline internal surface without the need for the pigs. Where regular batch treatment is required this may require additional tanks and pumps to be able to load and launch the pigging train efficiently.

- h) For pipelines corrosion inhibitors may require periodic pigging to be effective. Pigging will have a direct impact on the size of slugs and of the slug catcher.
- i) For pipelines intelligent pigging may be required during the lifetime (subject to RBA (3.3)). For pipelines from subsea production systems this may incur very large intervention costs, or even drive the development to a different option selection (e.g. looped flowlines, non-subsea development etc.).
- j) For pipelines and equipment, a zero or small corrosion allowance may impair the inspection planning process, requiring a FFS-based corrosion allowance to be calculated from day 1 of operation.
- k) For vessels and pipework, a zero or small corrosion allowance (1 mm [40 mils]) will jeopardize technical and/or economic feasibility of non-intrusive inspection with NDE tools.

2.10 DESIGN REASSESSMENT POINTS AND ROBUSTNESS OF DESIGN

The corrosion control design is based upon the information available at that stage in the design. If other corrosive species are detected at a later stage (e.g. organic acids), or if the data used in the design is found to be incorrect (e.g. appraisal drilling detects higher levels of carbon dioxide or hydrogen sulphide), the corrosion control design shall be reassessed.

Key design re-assessment points should be defined in the select phase and reviewed through;

- the detailed design phase,
- the execution phase
- into operation of the facilities.

The quality of the data used at a particular stage of the design should be reviewed. Where the accuracy of key data is low, the impact of this variation on the option selection / corrosion allowance requirement / inhibitor system availability requirement shall be assessed to ensure that the design is robust.

The accuracy of the final assessment should be within the cost estimate accuracy required for that phase of the project (e.g. level 1 cost estimates used in the assess design are

$\pm 40 \%$). Critical data that has low accuracy should be highlighted for additional data collection in the next phase of the project.

2.11 INHIBITOR SYSTEM DESIGN (INCLUDING CORROSION MONITORING)

The preliminary inhibitor system design is determined from the inhibitor system availability selected (2.4.3). The full design of the inhibitor system functionality (including the corrosion monitoring) is a deliverable of the define phase; note that it may be necessary to carry out the definition of critical parts of the inhibition system in the select phase of the project, if this becomes an essential part of option selection.

In this section the preferred ways of corrosion monitoring are indicated and suggested key performance indicators (KPI) are given. For pipelines if the potential corrosion is significant, intelligent pigging (IP) shall be carried out. Hence in most cases the local corrosion monitoring addressed here is intended to prevent deviations for the intended operation and to increase IP intervals. Similarly, for process facilities inspection intervals can be increased if adequate corrosion monitoring is in place and the data is used to its full extent

2.11.1 Corrosion Control Management

In **inhibited systems** the availability of the inhibition system (pump on/off, inhibitor tank level) shall be monitored.

Measuring corrosivity can be considered to monitor the effectiveness of the inhibition system, either by measuring the wall thickness or the corrosion rate in the system. In these cases there has to be certainty that the;

1. worst location can be identified, (e.g.. a water wet location at a suitable temperature, pressure, velocity, etc.)
2. location is accessible (e.g. in a subsea flowline, the highest projected corrosion rate is at the beginning of the line on the bottom of the sea, which is not an easy location to access).

If all these conditions are fulfilled, sufficiently sensitive corrosion measurement probes can be used to monitor the effectiveness of the inhibition system.

Iron counts have been used in this type of application, but are only successful if very regular analyses are made and the results are used for trend analysis. Individual values are usually meaningless because of background levels of dissolved iron.

Provision shall be made in the design so that the following Key performance indicators (KPI) can be measured or performed for inhibited systems, as required for the design availability per Table 2 in DEP 30.01.10.10:

- a) the number hours the inhibition system is not available
- b) Actual injected concentration compared with target injection concentration
- c) Inhibitor residual concentration compared to target concentration
- d) Average corrosion rate as compared to target inhibited corrosion rate. Depending on the sensitivity of the equipment for corrosive conditions this would be daily, weekly or monthly measurements
- e) Changes of corrosion rate or dissolved iron levels as a function of time.
- f) Unavailability of the corrosion monitoring data

The required frequency of assessment of these KPI will depend on the required inhibitor system availability (2.4.3), and the response time of that particular KPI. For primary KPI the response time must be in line with the required reporting frequency (daily, weekly, monthly depending on the required availability). Some of the KPI can be designated as secondary KPI where a longer response time is acceptable.

2.11.2 Wall thickness measurements used for corrosion rate monitoring

This type of monitoring shall only be used if the worst location is known with certainty and is accessible. The type degradation, i.e. general or localised corrosion also has to be known for this type of monitoring to generate relevant data; it is rarely possible to use this approach if the type of degradation is localised corrosion

The **wall thickness monitoring** techniques that can be used are;

- Corrosion rate monitoring spools (e.g., FSMTM)
- Pulsed Eddy Current,
- ultrasonic wall thickness
- permanently mounted ultrasonic mats

In view of the sensitivity of these methods they provide a semi-continuous or discontinuous record of the wall thickness of a (set of) location(s).

KPIs are in all cases recorded wall thickness (loss) compared to the target wall thickness and timely availability of wall data.

For subsea pipelines and particularly for subsea developments, there is the complexity of whether the monitoring is placed on the accessible ends of the pipeline (topsides facilities or onshore) or installed subsea.

For monitoring at the ends of the pipeline, this can introduce considerable uncertainty on the relevance of the data to the actual pipeline conditions. For onshore pipelines there is more flexibility on where the corrosion monitoring can be installed, though typically this also is installed only at the inlets and outlets.

Corrosion monitoring shall focus on collecting data that is critical for Risk Based Assessment (RBA – see 3.3) and helps to narrow the uncertainty band around the major factors in the RBA.

2.11.3 Inhibitor Injection Equipment

Detailed requirements for chemical injection equipment shall be required as identified in DEP 31.01.10.10-Gen SPE, "Chemical Injection Systems".

2.12 CORROSION INHIBITION SYSTEM COMMISSIONING

2.12.1 Commissioning

Commissioning occurs in the execute phase. There may be specific corrosion concerns during the commissioning phase that should be reviewed on a case-by-case basis prior to the start of commissioning. For example;

- will all the hydrotest water be removed prior to introduction of process fluids
- how long will hydrotested systems be in contact with oxygen prior to start up, etc.

Special once off chemical treatments may be required to deal with these problems.

Commissioning of inhibition system, includes commissioning of the corrosion monitoring systems (both process parameter monitoring and corrosivity monitoring), and the inhibitor injection system (2.11.3). For some types of corrosion monitoring the corrosion probes are not installed into the system until process fluids are first introduced, to avoid damage to the probes during commissioning activities. If this is the case, these probes shall be installed towards the end of the commissioning phase; installation of probes shall not be deferred to the operations phase.

During commissioning a review of the KPIs shall be carried out with the operations personnel, to see if they are realistic, achievable and can be monitored (3.2.1).

The inhibitor system shall be started at the default (conservative) injection rates determined in the full inhibitor selection programme, and may be more heavily dosed for a short period

to establish an initial inhibitor film (2.6.1). Optimisation of the inhibition system shall not be attempted until;

1. operations are stable
2. A baseline on the inhibitor system monitoring data has been developed (3.6.3).

A quick check of the corrosion monitoring systems should be carried out as soon as first process fluids are introduced, to assess whether the inhibitor is performing as expected.

During the commissioning phase operations staff shall be trained up in the specifics of the integrated inhibition system for the particular development by the Materials and Corrosion TA2 from the project team (3.5).

In some developments the inhibitor will not be required on day one of production e.g. oil systems with no initial water production. For these cases the inhibitor system shall still be fully commissioned and run for the initial production until it can be demonstrated that the inhibitor system, including all corrosion monitoring equipment are operating correctly.

Criteria for shutdown and restart of the inhibition system shall be developed in the define phase. The reason for this approach is that there have been examples where the inhibitor system is required in say year two for production and it is then found to be non functional and cannot be switched on.

2.12.2 Start Up

If the inhibition system has not been started up in the commissioning phase, it shall be started up with first production at the default (conservative) injection rates determined in the full inhibitor selection programme. No optimisation of the inhibition system should be attempted until operations are stable and a baseline on the inhibitor system monitoring data has been developed (3.6.3). A quick check of the corrosion monitoring systems should be carried out as soon as first process fluids are introduced to assess whether the inhibitor is performing as expected.

The full inhibitor selection programme (2.6.1) will have checked inhibitor compatibility with other chemicals in the system, the impact of the inhibitor on downstream plant and assessed discharge considerations for the inhibitor. During start up and initial production all the factors shall be verified with actual field data (i.e. confirming no negative impact).

2.13 INSPECTION TECHNIQUES

The corrosion and inspection integrity management philosophy is developed in the define phase. The Field Inspection Plan / RBI Plan / Baseline Inspection are covered in the Execute phase. These evolve in the operate phase into two different controls:

1. pipelines
2. facilities.

2.13.1 Inspection of Pipelines by Intelligent Pigging

Intelligent pig selection for a particular pipeline system is one of the deliverables in the define phase. This includes assessment of the available intelligent pigs for the pipelines and determining the initial inspection frequency (i.e. when the first inspection is required)

The initial inspection frequency shall be based on a Pipe RBA analysis and include:

- minimum required sensitivity for the selected pig (how much wall thickness change needs to be detected);
- assessment of worst case corrosion rate. The timing may take into account lowest likely inhibitor system availability and an assessment of how accurate the predicted inhibited corrosion rates are.

Note that this initial inspection is to validate corrosion control effectiveness, and thus shall not be replaced by wall thickness pig runs scheduled during pre-commissioning or in the first few months of operation – what was previously considered a “baseline survey” – when the detectability of operating corrosion is low.

In operation the time between intelligent pigging shall be based on one of the following:

- fixed time based frequencies (based on experience);
- frequencies dictated by government regulatory bodies;
- frequencies based on PIPE-RBA analysis (3.3).

The PIPE-RBA analysis shall be used whenever this is allowed by government regulatory bodies and adequate data is available.

If corrosion damage is detected, a suitable methodology to assess the severity shall be used. For general and localised corrosion the DNV-RP-F101 method (incorporated within PIPE-RBA) shall be used.

2.13.2 Alternative Methods of Pipeline Inspection

This document only covers internal corrosion assessment. Other than intelligent pigging the following may be considered:

- UT on pipeline ends
- For onshore lines, dig up and inspection of buried sections; UT inspection of exposed sections
- Subsea diver/ROV inspection at accessible areas such as towheads, PLEMs, etc.
- Internal inspection of pig launchers and receivers

When using these techniques which do not cover 100% of the pipeline, an assessment of the inspection effectiveness shall be carried out, to assess if this approach will adequately detect corrosion damage and mitigate

2.13.3 Inspection of Process Plant

Inspection using wall thickness measurements has been covered under Inhibition System Design (2.11.2). For piping, vessels and tanks a number of factors have to be included in selecting the inspection technique used and how they are applied:

- a) Corrosion mechanism, associated morphology and type of corrosion damage, and potential wall thickness loss shall be considered. Also identify the highest risk areas for inspection;
- b) Inspection techniques shall be selected in line with the corrosion mechanisms (e.g. do not use isolated "keypoint" UT measurements to detect pitting);
- c) For the selected inspection technique and damage mechanism, identify the appropriate minimum area of coverage;
- d) Inspection data shall be used to assess;
 1. the current system integrity,
 2. the corrosion rate (considering repeatability, tolerances, and accuracy)
 3. the remaining system life (accuracy depending on the corrosion rate assessment used).

Ensure software is in place to carry out this process and make the most use out of the data collected; selection and population of the Corrosion Inspection Management System (CIMS) is an Execute phase control.

- e) Certain areas are difficult to inspect, e.g., lagged equipment, vessel nozzles, small bore piping or just poor accessibility. These locations may require different inspection techniques, intrusive inspection rather than non-intrusive inspection (i.e. requiring a shutdown for access), removal of insulation or scaffolding. These all have to be considered in the integrated inspection plan. Where possible these difficult to inspect areas shall be designed out.

- f) All inspection techniques used require procedures, calibrated equipment and trained (certified) personnel. These requirements shall be defined and detailed in The Field Inspection Plan in the Execute phase
- g) Internal inspection of vessel and tanks may be required by government regulations. This process should be challenged, both in the project phase and later in operations if there is a good technical justification for not carrying out internal inspection. Where allowed, non intrusive inspection plans shall be developed.

These factors shall be managed through the Risk Based Assessment process (3.2) and set up during the execute phase. This is an integrated approach that combines consequence of failure and likelihood of failure to assess the risk of failure. This shall also be used to check the integrity of the facilities .

The initial inspection of the facilities shall be based on the earlier date of the following:

- The date when the inspection techniques could detect measurable loss (within the sensitivity and accuracy of the inspection technique) at the maximum corrosion rate in the system that could occur undetected by other means.
- The date per S-RBI planning rules, such that an appropriate margin of risk is preserved for the component, considering inspection accuracy.

In operation, the time between inspections shall be based on one of the following:

- Fixed time based frequencies, (based on experience);
- Frequencies dictated by government regulatory bodies;
- Frequencies based on RBI analysis (4.2).

The RBI analysis choice shall be used whenever this is allowed by government regulatory bodies and adequate data is available.

3. CORROSION MANAGEMENT

3.1 CORROSION MANAGEMENT FRAMEWORK

The corrosion management framework (CMF) looks at all common threats and assesses the barriers to those threats. The CMF covers how those barriers are maintained and what inspection requirements are needed to assess the integrity of the system. As CMF covers systems of all materials (not just carbon steel), the CMF is covered in DEP 39.01.10.11.

The initial materials threats analysis shall be completed as part of the initial materials selection in the Select phase . The formal review that identifies and quantifies all corrosion threats to the installation for all the different modes of operation (e.g. normal operation, shutdowns, start up, ramp up, etc.) is referred to as the corrosion risk assessment, or as the Failure Modes and Effects Analysis (FMEA); this shall be carried out in the define phase and updated in the Execute phase .

These all feed into the CMF, and the preliminary CMF shall be produced in the Define phase , with the full CMF completed in the execute phase .

The CMF is a live tool for the life of the facility, and it is assessed on a regular basis for each asset in the operate phase .

3.2 CORROSION MANAGEMENT MANUAL

A concise and current Corrosion Management Manual (CMM) is the key to the successful implementation of the corrosion management strategy. The CMM is an integral part of the CMF, and is a live document for the life of the facility. A CMM shall be produced in the required format covered in DEP 39.01.10.11-Gen.

At the materials selection stage (preliminary work in the select phase, final work in the define phase) the facility shall be divided into systems, each characterised by a generic description of the fluid contained (e.g. oil processing, fuel gas, fire-water, etc.), and sub-systems which are exposed to similar corrosion threats, and are expected to have (broadly) similar corrosion failure probabilities. The sub-systems will be allocated according to the corrosion threats to which they are exposed (i.e. they can be considered as corrosion systems (2.3.1)).

3.2.1 Key Performance Indicators for Corrosion Control

For each system (or for each individual item for critical facilities), KPIs shall be generated during the define phase; these will be used in operation on a daily, weekly or monthly basis, depending on the required corrosion control system availability to check that the system is performing as expected. KPIs for the inhibition system have previously been discussed (2.11.1). They shall incorporate alarm points, and recovery procedures (e.g. what to do if the residual inhibitor concentration drops below a critical concentration). During the commissioning phase the KPIs shall be reviewed to see that they are realistic, achievable and can be monitored, with modifications made as appropriate.

During operations, in addition to the short term data assessed by the KPIs, the long term data shall be compiled and assessed annually and more frequently if there are any problems. This long term data assessment can be integrated into the risk based assessment process (3.3).

3.3 RISK BASED ASSESSMENT

RBA directly follows on from the CMF. For pipelines this is usually first considered in the Pipeline Integrity Management Philosophy in the Define phase; however it may be necessary to carry out a preliminary RBA in the select phase, as it can be used to predict lifetime inspection requirements needed for the economic assessment of some of the design options.

The Pipeline Integrity Management System is written in the Execute phase , and this shall include the setup and population of the Pipe RBA database for the pipelines. The Pipe RBA

tool shall be used for RBA of pipelines. Pipeline RBA is a live process through the life of the facilities ; this is updated on an annual basis and after each intelligent pig run.

For other pressure containing facilities (piping, vessels) and atmospheric storage tanks, RBA shall be carried out in the execute phase . S-RBI shall be used for RBA of these facilities. RBA is a live process through the life of the facilities and is updated after each inspection programme (all facilities).

3.4 CORROSION INSPECTION MANAGEMENT SYSTEM

A substantial amount of inspection and monitoring data will be collected over a facility's life. The data shall be analysed, for example, with RBA systems. The fixed data, inspection data, monitoring data and integrity data shall be stored in an electronic database, called the Corrosion Inspection Management System (CIMS)

Where a project feeds into an existing OU, the existing CIMS of the OU shall be used. For projects that will become a new OU, or where an existing CIMS system is to be changed out, the new global standardised CIMS shall be adopted.

3.5 ASSET REFERENCE PLAN

There is a requirement commencing at the define phase, to demonstrate that all the critical activities and threats to a facility's technical integrity, including the corrosion threat, have been fully evaluated and the impact on cash flow quantified. This is referred to as an Asset Reference Plan (ARP).

The ARP documents the maintenance, inspection and corrosion control activities that contribute to the Operations Reference Plan for the life of a field, and is a key tool in Asset Management. It demonstrates that all activities, resources, threats and opportunities for improvement to a facility's technical integrity have been fully evaluated and the impact on cash flow quantified over the life cycle. The ARP will be matured as the field development proceeds from define through to execute, and shall form part of the hand-over documentation from the project, to be maintained as a 'live document' by the asset holder.

Adequate corrosion control activities (initially identified in the select phase) shall be incorporated in the ARP. Inspection and monitoring are carried out to confirm the adequacy of the corrosion control activities and operation within the operating envelope. Corrosion mitigation and rehabilitation are required in those cases where corrosion control is inadequate as a result of which the technical integrity cannot be safeguarded over the required operational life.

3.6 COMPETENCY ASSURANCE

The personnel involved in the process of achieving corrosion control include;

- the pipeline maintenance engineer
- operator
- corrosion engineer
- production engineer
- production chemist
- pipeline engineer.

Required training and level of competence of the personnel shall be defined in the execute phase as part of the Operations Organisational Resourcing, Training & Competence Assurance Plan. This requires operating Company input if not available as part of an integrated project team. Experienced lead personnel shall be selected/assigned to carry the corrosion management issues from design into operations, and train up operations personnel in the specifics of the system during commissioning.

As previously stated, the achievement of high levels of inhibitor availability is critically dependent on the people element, particularly during operation. In the system design,

efforts should be made to reduce the human factor (e.g. by automated systems), though it should be recognised that the human element cannot be removed altogether. High levels of inhibitor availability will not be achieved unless there is adequate training and emphasis from management (e.g. key performance indicators to be met).

During the commissioning phase, staff shall to be trained up in the

- CMM,
- CIMS,
- integrated inhibition system operation (from inhibitor supply through to corrosion monitoring)
- corrosion requirements in the ARP.

In operations any new staff shall to be trained up on the requirements of these core documents; key part in the success of Corrosion Management in the operate phase is the training and awareness for operations, maintenance, production chemistry and materials & corrosion staff.

3.7 CORROSION MANAGEMENT AS A LIVE PROCESS

A model for corrosion management, which illustrates the information flows required and emphasises the multi-disciplined nature of the process is shown in Figure 1. The model incorporates a process that optimises use of materials and corrosion engineering knowledge.

All the activities in this process require excellent two-way communication between materials and corrosion engineers, and other disciplines throughout an organisation, i.e. a multi-disciplined effort. The process shall be first used at the assess stage of a project and then revised throughout the lifetime of the installation.

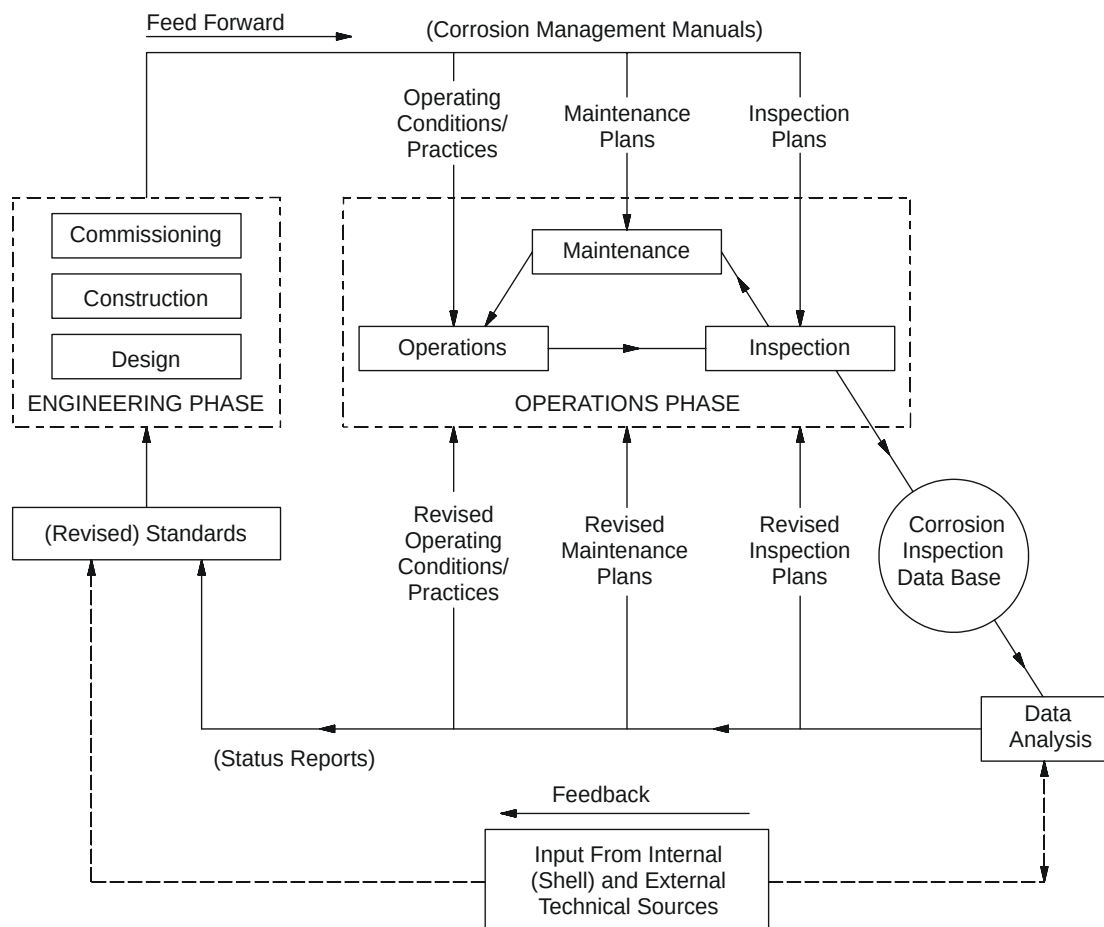


Figure 1: Corrosion Management Information Flows

Items covered in the design phases include the Corrosion Management Manuals and the Corrosion Inspection Database (CIMS). This section covers the other parts of the Corrosion Management Cycle in Operations.

3.7.1 Deviation Control

The establishment of base line operating conditions and practices, and maintenance and inspection plans in the Corrosion Management Framework, provides a basis for deviation control, principally through the use of KPIs, (3.2.1).

There are three types of deviation:

- (planned) changes in operating practices;
- (gradual) changes in operating conditions (picked up by KPIs (3.2.1));
- Non-compliance with planned activities (picked up by KPIs, management reviews and audits (3.7.5)).

Any changes in operating practices for an installation, possibly suggested by operating experience or operational needs, shall be:

1. evaluated against the CMF (3.1),
2. evaluated against historical data,
3. agreed by all relevant disciplines and fully documented in a revised CMF;

The KPI (3.2.1), RBA analysis (3.3) and the ARP (3.5) shall also be revised. This sequence of documentation will provide an audit trail through an installation's operational history.

Changes in operating conditions shall be assessed against the defined operating window of the facility, to assess whether they can be accepted, or whether further analysis is required.

A management of change system shall be in place to identify non-compliance of planned activities, particularly those related to the integrity of the system. The control system should identify who has authority to authorise a change from planned activities and the review process required.

3.7.2 Corrosion Mitigation and Rehabilitation

Corrective action shall be taken to prevent failure if higher-than-expected corrosion rates are detected through monitoring or inspection,. The first step is to check whether the corrosion mechanism is fully understood. In case of doubt, this should be confirmed by an appropriate investigation, e.g. field corrosivity measurements. Once the mechanism is known, several fall-back options are available, for example:

- a) apply inhibitor or increase inhibitor concentration;
- b) variation to corrosion control procedures;
- c) change to a more effective inhibitor;
- d) increase pigging frequency;
- e) initiate a batch inhibition programme;
- f) reduce the design life of the facility;
- g) de-rate the facility;
- h) improve the availability of the corrosion control system;
- i) replace or repair section of the facility.

The choice of corrective action will of course depend on the cause of the problem, and an evaluation of the consequences. It is important that analysis of the monitoring and inspection data, and a "decision tree" for taking quick corrective action be included in the

corrosion management programme. An experienced and qualified corrosion engineer shall be assigned the responsibility of evaluating the monitoring and inspection data, and making the necessary recommendations. The RBA process can be followed to assess the various options in a structured manner.

3.7.3 Optimising Inhibitor Injection Rates

During operations the inhibitor injection rates shall be re-assessed from time to time.

During operations start up, the inhibitor system shall be started up at the default conservative injection rates determined in the laboratory test programme. These rates are used during initial operations, while there still may be frequent interruptions in operations and while a baseline on all the inhibition system monitoring data is developed. Once operations are stable, work on optimisation of the inhibitor injection rates can be considered. This is usually carried out in partnership with the chemical supplier and may require additional temporary monitoring equipment to be installed.

After the initial optimisation, optimisation later in field life may be required for one of the follow reasons:

- Operating window changes significantly, (3.7.1);
- Higher than expected corrosion rates are detected, (3.7.2);
- If the inhibitor is changed (after a full selection programme), (2.6.1).
- If the oil-water ratio changes enough to impact dosage due to partitioning effects.

3.7.4 Field Corrosivity Testing

Procedures and tools have been developed to measure essential variables of corrosion processes in produced fluids in the field. This includes measuring the concentrations of dissolved oxygen, carbon dioxide and characteristics of the water phase, bacteria and the corrosivity to carbon steel. Field corrosivity testing may be required in response to changes in the operating window, as part of deviation control (3.7.1), or as part of a management review (3.7.5).

3.7.5 Management Review

The quality of Corrosion Management shall be assured and improved by the Asset Holder via the following means:

- a) Assigning competent personnel
- b) Pipeline integrity verification reports (from "Pipe RBA")
- c) Key performance indicators (KPIs)
- d) Audits & Reviews, including Safety Cases
- e) Compliance to legislative requirements (where local legislation does not allow a goal setting regime). Note if these requirements conflict with the CM requirements or are more stringent, the asset holder should consider making representation to the applicable body to change the regulations
- f) Benchmarking.
- g) Field corrosivity testing (3.7.4). This could be employed on a routine basis during the facility life to give an improved understanding of the corrosion mechanism. Better corrosion control and cost savings.
- h) By defined protocols in the Production Integrity Management System,

4. REFERENCES

In this DEP, reference is made to the following publications:

- NOTES:
1. Unless specifically designated by date, the latest edition of each publication shall be used, together with any amendments/supplements/revisions thereto.
 2. The DEPs and most referenced external standards are available to Shell staff on the SWW (Shell Wide Web) at <http://www.shell.com/standards/>.

SHELL STANDARDS

	DEP 30.01.10.10-Gen.
Non-Metallic Materials – Selection and Application	DEP 30.10.02.13-Gen
Clarifications and amendments to ISO 15156: Materials for Use in H ₂ S Environments in Oil and Gas Production	DEP 30.10.02.15-Gen
Chemical Injection Systems	DEP 31.01.10.10-Gen
GRP Pipeline and Piping Systems (amendments / Supplements to UKOOA document)	DEP 31.40.10.19-Gen
Selection of Materials for Life Cycle Performance (Upstream facilities) Materials Selection Process	DEP 39.01.10.11-Gen
Selection of Materials for Life Cycle Performance (Upstream Facilities) Equipment	DEP 39.01.10 12-Gen

AMERICAN STANDARDS

Pipeline Transportation Systems for Liquid Hydrocarbons and other Liquids	ASME B31.4
Gas Transmission and Distribution Piping Systems	ASME B31.8

Issued by:
American Society of Mechanical Engineers
ASME International
Three Park Avenue, M/S 10E
New York, NY 10016
USA

EUROPEAN STANDARDS

Corroded Pipelines	DNV-RP-F101
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Det Norske Veritas
VerHasveien 1,
NO-1322 Hovik
Norway

APPENDIX A FAILURE MODES BY CORROSION SYSTEM

For each of the defined corrosion systems, failure modes have been assigned based on a review of the corrosion risks of that environment and discussions with the operations personnel. For the internal risks, these are covered in the following 2 tables:

Table A.1: Failure Modes that do not Routinely Need to be Considered;

These failure modes only need to be consider if identified by materials and corrosion engineering for that facility/system:

System Types	Failure Modes	Corrosion Mechanism/Location focus for corrosion	Failure Threat Code
CS	Crevice Corrosion	Threaded connections in CO ₂ corrosion. Operationally not seen as a major risk (some may still exist on old topside facilities, though not permitted on process piping in the current piping DEP)	CREVICE
		Flange gaps where liquids are trapped in CO ₂ corrosion. Benchmarking with PDO - not seen as a major risk	CREVICE
	Low Temperature Embrittlement	Not normally a problem for facilities in operation; need to review under what conditions the facilities will blowdown. Under blowdown conditions low temperatures can occur. For new facilities all cases where this could occur are covered by materials selection. For existing facilities only needs to be considered where a plant change alters the service/blowdown requirements of a line which is not designed for low temperature service. May also occur across the choke of a high pressure, low liquid well, or for a short period of time during the start up of a high pressure well.	
CRA	None	CRA selected for resistance to environment	
All systems	Cracking	SSCC, CSCC, HIC. For new facilities for all Sour systems this is covered by materials selection. Only needs to be considered on systems not designed to be sour which later go sour. For CSCC consider both external hot and internal high chloride exposures.	SSCC, CSCC, HIC
	Weld Corrosion	Galvanic corrosion in the presence of CO ₂ . Operationally not seen as a major risk where there is good corrosion control. Weld inspection is not usually carried out unless there is significant corrosion detected elsewhere (corrosion control not working properly); in these cases corrosion in the weld metal or HAZ can be many times the rate on the parent metal.	WELD

Table A.2: Summary of Internal Failure Modes for Each Corrosion System to be Considered in the RBA Analysis

These failure modes are a minimum requirement. OUs/project may have additional modes that need to be considered

System Description	Failure Modes	Corrosion Mechanism/Location focus for corrosion	Failure Threat Code
Wet Multiphase Gas (Gas flowline)	General corrosion	CO ₂ in flowing conditions	CO2GEN
	Localised corrosion	CO ₂ in stagnant/low flow conditions	CO2PIT
		Under deposit corrosion	
		CO ₂ /H ₂ S in stagnant or flowing conditions	H2SPIT
	Erosion by Fluid Stream at High Velocity	Focused on bends, tees, downstream of reducers and control valves, vessel inlet and outlet nozzles	EFLUID
Wet Gas	Erosion by Sand. Entrained Sand Causing Erosion	Focused on bends, tees, downstream of reducers and control valves, vessel inlet and outlet nozzles	ESAND
	General corrosion	CO ₂ in flowing conditions	CO2GEN
	Localised corrosion	CO ₂ in stagnant/low flow conditions	CO2PIT
		Under deposit corrosion	
		CO ₂ /H ₂ S in stagnant or flowing conditions	H2SPIT
Dry Gas	Erosion by Fluid Stream at High Velocity	Focused on bends, tees, downstream of reducers and control valves, vessel inlet and outlet nozzles	EFLUID
	Otherwise potentially non corrosive. If not dry, treat as Wet Gas		
Dry Gas/Condensate	Erosion by Fluid Stream at High Velocity	Focused on bends, tees, downstream of reducers and control valves, vessel inlet and outlet nozzles	EFLUID
	Otherwise potentially non corrosive. If not dry, treat as Gas Flowline. From experience, Dry Gas/Condensate systems have a higher risk of going wet than straight Dry Gas system, because of problems drying the condensate		

System Description	Failure Modes	Corrosion Mechanism/Location focus for corrosion	Failure Threat Code
Wet Multiphase Oil Oil Flowline	General corrosion	CO ₂ in flowing conditions	CO2GEN
	Localised corrosion	CO ₂ in stagnant/low flow conditions	CO2PIT
		Under deposit corrosion	
		CO ₂ /H ₂ S in stagnant or flowing conditions	H2SPIT
		Oxygen entry (e.g. through pumping sumps)	O2PIT
		SRB in Systems contaminated with Seawater (e.g. through pumping sumps, saver pits or from sucker rods)	SRBPIT
	Erosion by Fluid Stream at High Velocity	Focused on bends, tees, downstream of reducers and control valves, vessel inlet and outlet nozzles	EFLUID
	Erosion by Sand. Entrained Sand Causing Erosion	Focused on bends, tees, downstream of reducers and control valves, vessel inlet and outlet nozzles	ESAND
Wet Oil	General corrosion	CO ₂ in flowing conditions	CO2GEN
	Localised corrosion	CO ₂ in stagnant/low flow conditions	CO2PIT
		Under deposit corrosion	
		All low risks - these systems usually flowing	
		CO ₂ /H ₂ S in stagnant or flowing conditions	H2SPIT
		low risks - these systems usually flowing	
		Oxygen entry (e.g. through pumping sumps)	O2PIT
		MIC in Systems contaminated with Seawater (e.g. through pumping sumps)	MICPIT
Wet Condensate	General corrosion	CO ₂ in flowing conditions	CO2GEN
Dry Oil	Potentially non-corrosive. If not dry, treat as Wet Oil		
Dry Condensate	Potentially non-corrosive. If not dry, treat as Wet Condensate		

APPENDIX B CO₂ CORROSION MITIGATION BY PH CONTROL TECHNIQUE

B.1 INTRODUCTION

pH control or pH stabilisation is a CO₂ corrosion mitigation option that can be applied in wet, sweet gas systems in which continuous glycol or methanol injection is applied for hydrate prevention and in which only condensation water is present.

Laboratory experiments and field data show that the corrosion rate can, typically, be brought to levels well below 0.1 mm/year (4 mils/year).

The scale formation by pH control in glycol/methanol systems cannot be predicted by current CO₂ prediction models (including Hydrocor) and models should therefore not be used for the design of a pH control system.

B.2 APPLICATION LIMITATION

pH control is strictly limited to conditions with condensed water only.

B.3 pH CONTROL CHEMICALS

Various chemicals have been used for successfully for pH control in wet gas pipelines:

- MDEA (MethylDiEthanolAmine), which has a lower freezing point and has no secondary effect. MDEA is chemically stable under normal regeneration conditions.
- NaHCO₃ (baking powder), Na₂CO₃.10H₂O (Sodium Carbonate or soda ash), or NaOH (Sodium Hydroxide), which can be used either in glycol or methanol. These are environmentally more acceptable. Once in the system, the equilibrium is controlled by the CO₂/HCO₃⁻ system (all three chemicals are converted to bicarbonates).

B.4 REQUIRED pH INCREASE

A pH shift of 1.5-3 units compared to the “pure” condensed water pH is usually recommended. The actual target pH will depend on the CO₂ partial pressure and the glycol concentration. Lab experiments shall be carried out to select the required pH increase.

B.5 SOUR SYSTEMS

pH control shall not be used in sour systems.

B.6 APPLICATION GUIDELINES

The following guidelines are suggested when planning development of the pH control option.

- a) pH control shall only be applied for gas/condensate systems in which either glycol or methanol are used for hydrate prevention.
- b) There must be no formation water present.
- c) pH control shall not be applied for sour conditions.
- d) The fall-back option of corrosion inhibition shall always be available (in case formation water is produced or if for any reason pH control cannot reduce corrosion to an acceptable level).
- e) Lab experiments at simulated field conditions shall be carried out to determine the required pH increase.
- f) Sodium bicarbonate shall to be considered as the default pH control chemical; it can be injected as a NaOH solution.
- g) Sufficient time shall be taken for the stepwise batch injection in order to avoid problems such as precipitation or foaming.

- h) With the higher release of CO₂ in the glycol boilers due to the decomposition of sodium bicarbonate, corrosion is possible in the re-flux system; CRA shall be selected for this part of the system.
- i) Regular monitoring of the pH is essential, followed by adjustment to the target value if required.
- j) Regular monitoring of the various iron levels (Fe²⁺, solid iron particles) is essential to check how effective the pH control is.
- k) Regular monitoring of the salts (e.g., NaCl, formates, acetates) accumulating in the water is required. Tolerance levels for these salts need to be identified based on system physical conditions. If tolerances are exceeded, provision for blowdown and dilution or desalinization may be needed.
- l) Filters are required to filter out the solids iron particles.

APPENDIX C EQUIPMENT ITEMS TO BE INCLUDED AND EXCLUDED FROM THE SCOPE

This DEP covers all production systems that could reasonably be fabricated from carbon steel, with a focus on those facilities that use an inhibitor for corrosion control. This DEP covers all existing production systems where inhibitors are used; note that this may include some existing facilities that utilise inhibition that would not be so designed if they were redesigned with today's knowledge. This covered in Table C.1 below.

For some equipment items corrosion resistant materials (CRM, i.e. CRA plus non-metallics) is an alternative corrosion control option that should be considered. For equipment items that are excluded from the scope of this DEP, they will be fabricated from a CRM or carbon steel with a different corrosion control system.

Note that inclusion of carbon steel does not imply use of carbon steel plus inhibition; other corrosion control methods could be used. Possible corrosion control options are given; the general comments give some more background to the corrosion control options.

For the corrosion control options of carbon steel without inhibitor, with or without a corrosion allowance the following general statements apply.

For topsides:

- CS with no inhibitor may be considered in oil production where
 1. there is a very low level of corrosive species,
 2. limited life is required,
 3. protection is provided by zero water production, no free water phase (water dissolved or entrained) or inhibitive properties of the oil.
- CS with no inhibitor may be considered in gas production where there is a very low level of corrosive species, or limited life is required.

For downhole:

- CS with no inhibitor may be considered in oil production where;
 1. there is a very low level of corrosive species
 2. limited life is required
 3. protection is provided by zero water production, no free water phase (water dissolved or entrained), inhibitive properties of the oil or protective scales.
- CS with no inhibitor may be considered in gas production where
 1. there is a very low level of corrosive species
 2. limited life is required
 3. protection is provided protective scales.

The difference between topsides and downhole is the possible reliance upon protective scales downhole; this is supported by:

- Generally higher temperatures, giving better protective scales.
- More favourable flow regimes.
- Lots of field experience.
- Low risk of tubing failure can usually be accepted from an environmental and safety point of view because there will be no release of process fluids to the environment. This is not the case for pipelines and topside facilities

The exception to this approach is where workover costs are high (e.g. subsea, offshore and deep wells) and in critical production areas.

For all these cases (topside and downhole) assessment must be made of the conditions under which the fluids could become corrosive and the risks of this occurring to determine

the required corrosion allowance if any and whether this method of corrosion control is viable.

Table C.1 Corrosion Control Options for Different Types of Equipment used in Production Systems

	Included/ excluded in scope of this document	Corrosion Control Options						General comments
		CS + with no or minimal CA	CS + with CA	CS + with CA + inhibition	CS + with no or minimal CA with dehydration	CRA	Non-Metallics	
Prod Systems								
Downhole tubing + couplings and liners	yes	yes	yes	yes	no	yes	yes	Tubulars are not designed with a CA. End of life is typically when remaining wall thickness has sufficient strength to allow tubing to be pulled. (typically 45% remaining WT); this gives an effective CA.
Springs	no	no	no	no	no	yes	no	All CRA components
Control Lines	no	no	no	no	no	yes	no	
Sand Screens	no	no	no	no	no	yes	no	
Valve, Stem, Fittings, Seal Rings etc	no	no	no	no	no	yes	no	
Casing	no	yes	no	no	no	no	no	Where there is no flow in the casing, it is protected by packer fluids. Where lift gas flows down the casing protection is provided by the same method used to protect the lift gas Where production flows up the casing it should be considered as “downhole tubing”.
Xmas Trees + Hanger + SSSV + Packer	Yes (see general comments)	no	yes	yes	no	yes	yes	Carbon steel trees do exist in operating fields, typically with CRA (coated) gates and seats. Hanger, SSSV and packer are typically CRA and so excluded

	Included/ excluded in scope of this document	Corrosion Control Options						General comments
		CS + with no or minimal CA	CS + with CA	CS + with CA + inhibition	CS + with no or minimal CA with dehydration	CRA	Non-Metallics	
Vessels	no	yes	yes	no	yes	yes	yes	The main risk in oil production vessels is from microbiologically induced corrosion bacteria (MIC), or oxygen in the system, not from dissolved acid gases. Inhibition is not relied upon to give protection in vessels. The most common form of protection on vessels is CRA or non-metallic linings; CS with a corrosion allowance has been used in multiphase oil systems (see general CS use comment). CS with a corrosion allowance has been used in dry hydrocarbon vessels, where CA is to cover periods where dehydration is out of specification.
Piping	yes	yes	yes	yes	yes	yes	yes	

	Included/ excluded in scope of this document	Corrosion Control Options						General comments
		CS + with no or minimal CA	CS + with CA	CS + with CA + inhibition	CS + with no or minimal CA with dehydration	CRA	Non-Metallics	
Heat Exchangers: Shell & Tube	yes (see general comments)	yes	yes	yes	yes	yes	No	Where there is a liquid stream entering the exchanger (as a carrier for the corrosion inhibitor) CS with inhibition could be used for the tubes. However tubes have limited wall thickness (to achieve good heat transfer) so possible corrosion allowance is minimal. Velocities in the tubes may also be a problem for inhibition. Tubes are most commonly of CRA (and the most corrosive fluid should go down the tubes if possible). Tubes are excluded from the scope. CS with inhibition is feasible for tube side and shell side shell components where there is a liquid stream entering the exchanger (as a carrier for the corrosion inhibitor) as higher corrosion allowances are possible and velocities are lower. Where the stream entering the exchanger contains no free liquids (i.e. no carrier stream for the inhibitor) CRA is used.
Heat Exchangers: Plate	no	yes	no	no	yes	yes	no	Plate heat exchangers are most commonly of CRA; with the small metal path between the hot and cold fluids (for good heat transfer) there is no room for a corrosion allowance. CS may be used in non corrosive service

	Included/ excluded in scope of this document	Corrosion Control Options						General comments
		CS + with no or minimal CA	CS + with CA	CS + with CA + inhibition	CS + with no or minimal CA with dehydration	CRA	Non-Metallics	
Heat Exchangers: Fin Fan	yes (see general comments)	yes	yes	yes	yes	yes	no	Tubes are always CRA; tubes are excluded from the scope. CS with inhibition is feasible for the header boxes where there is a liquid stream entering the exchanger (as a carrier for the corrosion inhibitor). Where the stream entering the exchanger contains no free liquids (i.e. no carrier stream for the inhibitor) CRA is used.
Glycol regeneration system	no	no	no	no	no	yes	no	Covered by relevant DEP. Inhibitors not used. Tower is CRA (clad). Reboiler protection is by pH control. Overhead lines are sometimes fabricated in CS, but can be prone to high corrosion rates (high level of CO ₂ in the overhead stream) so CRA is commonly used.
Flare and Relief System	no	yes	yes	no	no	no	no	Majority of time flare systems are purged with low pressure dry fuel gas and so are inert. System will be subject to corrosion for very short periods of time during venting. Systems are designed to be self draining so that liquid pools do not remain in the system after a venting event.
Rotating equipment	no	yes	yes	no	yes	yes	no	Rotating equipment components are mostly CRA. CS is sometimes used for dry (non-corrosive) parts of the system. Corrosion allowances are added to cover start up and shut down period when the system may be wet (condensation) for short periods of time

Pipelines

	Included/ excluded in scope of this document	Corrosion Control Options						General comments
		CS + with no or minimal CA	CS + with CA	CS + with CA + inhibition	CS + with no or minimal CA with dehydration	CRA	Non-Metallics	
Subsea/ Surface Flowlines	yes	yes	yes	yes	no	yes	yes	
Risers	yes	yes	yes	yes	no	yes	yes	
Flexibles	no	no	no	no	no	yes	yes	No carbon steel in contact with the process stream
Export Pipelines	yes	yes	yes	yes	yes	yes	yes	
Water Injection Pipelines	no	yes	yes	no	no	no	yes	Not included in the scope; different corrosion mechanisms and corrosion control options
Umbilicals	no	yes	yes	yes	no	yes	yes	No process fluids contained in the umbilicals