

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



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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