

PETRONAS TECHNICAL STANDARDS

DESIGN AND ENGINEERING PRACTICE

MANUAL

SELECTION OF MATERIALS FOR LIFE CYCLE PERFORMANCE (EP) – MATERIALS SELECTION PROCESS

PTS 39.01.10.11

DECEMBER 2010



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This revision of **PTS 39.01.10.11 – Selection of Materials for Life Cycle Performance (EP) – Materials Selection Process (Revision 1)** has been updated incorporating PETRONAS Lessons Learnt, Best Practice and new information issued by relevant industry code and standards. This is a major revision, which includes dividing the original PTS into two parts: PTS 39.01.10.11 addresses the material selection process and PTS 39.01.10.12. covers materials selection for specific equipment. The revision is so substantial that no attempt was made to highlight the changes.

The previous version of this PTS 39.01.10.11 (**January 2005**) will be removed from PTS binder/ e-repository from herein onwards.

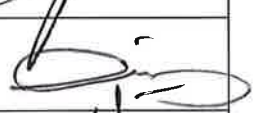
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PREFACE

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They are based on the experience acquired during the involvement with the design, construction, operation and maintenance of processing units and facilities. Where appropriate they are based on, or reference is made to, national and international standards and codes of practice.

The objective is to set the recommended standard for good technical practice to be applied by PETRONAS' OPU in oil and gas production facilities, refineries, gas processing plants, chemical plants, marketing facilities or any other such facility, and thereby to achieve maximum technical and economic benefit from standardisation.

The information set forth in these publications is provided to users for their consideration and decision to implement. This is of particular importance where PTS may not cover every requirement or diversity of condition at each locality. The system of PTS is expected to be sufficiently flexible to allow individual operating units to adapt the information set forth in PTS to their own environment and requirements.

When Contractors or Manufacturers/Suppliers use PTS they shall be solely responsible for the quality of work and the attainment of the required design and engineering standards. In particular, for those requirements not specifically covered, it is expected of them to follow those design and engineering practices which will achieve the same level of integrity as reflected in the PTS. If in doubt, the Contractor or Manufacturer/Supplier shall, without detracting from his own responsibility, consult the owner.

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1. INTRODUCTION

1.1 SCOPE

This PTS specifies requirements and gives recommendations for the process of selecting materials for production systems, from the reservoir to the export point. Detailed materials selection for specific equipment and complicated accessories is covered in PTS 39.01.10.12.

This PTS, in conjunction with PTS 39.01.10.12., is a revision of PTS 39.01.10.11. dated September 2005; see (1.6) regarding the changes.

These PTSs do not cover every contingency. Instead they offer options and in some cases guidance which option might be selected. It is the responsibility of the user to recognise when additional resources need to be brought to bear on a question or decision.

There are many equipment-based PTSs that contain materials-related information. It is the intent that PTS 39.01.10.11. and PTS 39.01.10.12. will contain all materials selection related information and that the equipment-related PTSs refer to these PTSs. This will be a gradual transition, which will be realised as other PTSs are updated. In case of conflict the Principal shall be consulted.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorised by PETRONAS, the distribution of this PTS is confined to PETRONAS and, where necessary, to Contractors and Manufacturers/Suppliers nominated by them.

This PTS is intended for use in exploration and production facilities. For refineries and chemical plants, reference should be made to PTS 30.10.02.11, which provides useful references to materials standards that can also be applied to upstream facilities.

If national and/or local regulations exist in which some of the requirements may be more stringent than in this PTS, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable with regard 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 PTS 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 PTS as closely as possible.

1.3 DEFINITIONS

For the purposes of this PTS the following definitions shall apply:

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

The **Manufacturer** 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 its design and construction. The Principal will generally specify the technical requirements. The Principal may also include an agent or consultant, authorised to act for the Principal.

The word **shall** indicates a requirement.

The word **should** indicates a recommendation.

1.4 ABBREVIATIONS

AC	Atmospheric Corrosion
CE	Carbon Equivalent
CMF	Corrosion Management Framework
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CUI	Corrosion Under Insulation
DCAF	Discipline Controls and Assurance Framework
EFC	European Federation of Corrosion
FEED	Front End Engineering Design
GRP	Glass Reinforced Plastic (Fibreglass). Also known as FRP (Fibre Reinforced Plastic) or GRE (Glass Reinforced Epoxy)
HE	Hydrogen Embrittlement
HIC	Hydrogen-Induced Cracking (also called Step-Wise Cracking, SWC)
HYDROCOR	Proprietary Shell computer program for calculating corrosion rates
HRC	Rockwell Hardness
HV	Vickers Hardness
MDMT	Minimum design metal temperature
NACE	National Association of Corrosion Engineers
OCTG	Oil Country Tubular Goods
OPMG	Opportunity and Project Management Guide
OR&A	Operations, Readiness & Assurance
PFP	Passive Fire Protection
PTE	Principal Technical Expert
PWC	Preferential Weld Corrosion
P-RBI	PETRONAS Risk Based Inspection
SCC	Stress Corrosion Cracking
SLC	Service Life Corrosion (Total estimated wall thickness reduction of carbon steel over the life of a project)
SME	Subject Matter Expert
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SSC	Sulphide Stress Cracking
SWC	Step-Wise Cracking (also called Hydrogen-Induced Cracking, HIC)
TOL	Top of Line

1.5 CROSS-REFERENCES

Where cross-references to other parts of this PTS are made, the referenced section number is shown in brackets. Other documents referenced by this PTS are listed in (5).

1.6 CHANGES FROM PREVIOUS EDITION

The previous edition of this PTS was dated January 2005. This is a major revision, which includes dividing the original PTS into two parts: PTS 39.01.10.11. (this PTS) addresses the material selection process and PTS 39.01.10.12. covers materials selection for specific equipment. The revision is so substantial that no attempt was made to list the changes.

2. MATERIALS SELECTION PROCESS

2.1 GENERAL

Materials selection is primarily a process of short-listing technically acceptable materials for an application and then selecting the most cost-effective option for the required operational life, bearing in mind Health, Safety and Environmental aspects, Sustainable Development, Technical Integrity and operational constraints. This is a multi-variable process, which might require several iterations before an optimal solution can be obtained. Part of this process should also be to assess which systems require materials optimisation and which can use standard materials selection guidelines.

The materials selection process shall follow the Corrosion Management Framework (CMF) as described in (2.2.4).

2.2 TECHNICAL INTEGRITY ASPECTS

2.2.1 General

Technical Integrity of wells, pipelines, and facilities is achieved when, under specified operating conditions, the risk of a failure that would endanger the safety of personnel, the environment, or asset value is tolerable and has been reduced to a level that is ALARP. The process of ensuring that Technical Integrity is described in the Technical Integrity Framework (Figure 1). Material selection is an integral part of the integrity activities that aim to ensure that all identified Safety Critical Elements are designed and engineered properly.

The Corrosion Management Framework described in (2.2.4) is part of the process that ensures that threats to technical integrity are fully identified and that the barriers required to assure technical integrity are properly maintained in order to meet the relevant Performance Standard (as identified during the risk assessment).

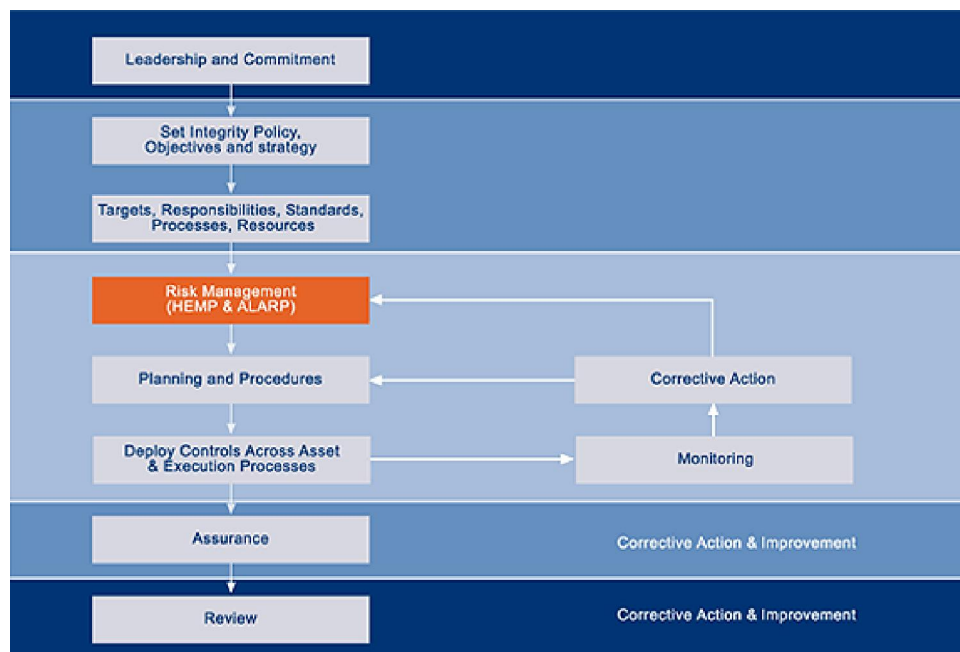


Figure 1 Technical Integrity Framework

2.2.2 Health Safety and Environment

Materials selection shall be in accordance with the HSE Hazards and Effect Management Process (HEMP). This process, identifies and assesses HSE hazards, implements control and recovery measures, and maintains a documented demonstration that major HSE risks

have been reduced to a level that is As Low as Reasonably Practicable (ALARP). This shall be done for the full lifecycle of assets and operations and uses the standard Risk Assessment Matrix (RAM). For High Risk or “severity 5” hazards bow tie diagrams with links to relevant details should be used to demonstrate tolerability and ALARP. The bow-tie diagram is a pictorial representation of how a hazard can be hypothetically released and further developed into a number of consequences. The left hand side of the diagram is constructed from a fault tree (causal) analysis and involves those threats associated with the hazard, the controls associated with each threat and any factors that escalate likelihood. The right hand side of the diagram is constructed from the hazard event tree (consequence) analysis and involves escalation factors and recovery preparedness measures. Material selection plays a key role in this process, because the integrity of barriers that prevent or mitigate threats or consequences often depends on the suitability of the material and guards or shields (coatings, inhibitors, shutdowns) that protect the material. The RAM is used in the Failure Modes and Effects Analysis process (see 2.2.4) to identify materials and corrosion related integrity risks and agree the barriers that are required.

2.2.3 Sustainable Development

Sustainable Development principles shall be applied as part of the materials selection process. During the past decade it has become clear that the availability of materials and the manufacturing capacity for materials and products is rapidly becoming a major constraint on construction capabilities and hence on energy production and development. Therefore it is important to use materials that are readily available and in ways that facilitate re-use. Thus one of the considerations should be to avoid mixing materials in such a way that they cannot be separated easily as this downgrades their value and limits their availability in the longer term.

2.2.4 Corrosion Management Framework

2.2.4.1 General

In selecting materials with a view to minimising the estimated life cycle costs, it will often be necessary to make use of materials that might, at some stage of their service lives, be subject to degradation by corrosion. Despite the term Corrosion Management Framework most of the principles also apply to other forms of gradual degradation such as erosion and wear.

Whilst such corrosion can sometimes occur during both predicted and unforeseen periods outside the normal operating envelope of a plant or other system, in many cases equipment is designed and constructed using carbon steel with a corrosion allowance that takes into account the corrosion expected during normal operation over the design life.

In either case, the threat of degradation must be adequately managed if the intended design life is to be achieved at minimum life cycle cost and corrosion management activities shall therefore be carried out within a structured framework that is visible, understood by all parties and clearly defines roles and responsibilities. Underpinning the corrosion management process is the threats and barriers matrix. See Appendix 1. This matrix defines the **common threats** in three groups: internal corrosion, external corrosion and mechanical degradation. These groups are further subdivided into specific common threats. Against each one of these threats, at least one **common barrier** is defined.

The barriers are defined as either primary or secondary. Primary barriers are those that are fully effective against a particular threat (provided they are properly maintained), i.e. they provide corrosion “prevention”. Secondary barriers may be less effective. They provide corrosion “mitigation”, i.e. control the degradation rate to an acceptable level and are normally selected for specific equipment on grounds of cost.

Once barriers against a certain threat have been selected, they have to be maintained. The responsibility for the maintenance of a particular barrier is outlined in generic procedure or

activity descriptions, which detail tasks, responsibilities, reporting and the relevant controlling documents.

The key to the Corrosion Management Framework is the identification of these corrosion threats and the maintenance of the corrosion barriers together with the compliance checks and verification measurements required to confirm their effectiveness.

Corrosion rates are often low enough for deviations or breaches of the barrier to go unnoticed for extended periods and there is often no perceived imminent threat to integrity. Even if the integrity itself is not imminently threatened, the economic life of the facility is likely to be severely reduced where corrosion barriers fail. It is therefore imperative that a system of compliance measurement is operated, so that any breach of the maintenance of a barrier is reported, and can be acted upon. Examples of such failures to maintain a barrier are:

- Inadequate or defective inhibitor injection systems, resulting in insufficient inhibitor availability or lack of control of inhibitor delivery; and
- Failure to maintain the protective coatings.

Compliance with the barrier requirements is only the first step in the corrosion management process. In essence, all these barriers must be maintained to ensure that material degradation is properly controlled. Inspection and corrosion monitoring are usually required to establish actual corrosion rates. Only if these are within the accepted design limits can it be stated that each barrier is effective, and that the threat to integrity is managed.

The formal review that identifies and quantifies all corrosion threats to the installation is referred to as the corrosion risk assessment, or as the Failure Modes and Effects Analysis (FMEA). It ranks each threat in relation to the risk; where "risk" is defined as the product of the probability of a failure and its consequences. The methodology follows that set out in the P-RBI guidelines. For a new installation, the risk assessment is based on theoretical calculations (e.g. corrosion rate modelling), together with experience with generically similar systems and sub-systems. Once the installation is in operation, the corrosion risk assessment will be updated on the basis of inspection and monitoring data.

The intent of the corrosion risk assessment is to provide input to the P-RBI process, primarily the mechanism, possible location and rate of degradation, to enable inspection to verify corrosion problems. It will also form the basis of selecting corrosion mitigation and monitoring activities. The data obtained from the P-RBI process is entered into an P-RBI equipment database to allow analysis and trending, and feedback to the corrosion risk assessment process.

2.2.4.2 Corrosion Management Program

A concise and current Corrosion Management Program (CMP) is the key to the successful implementation of the corrosion management strategy. At the materials selection stage the facility should 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.

The key corrosion threats and corrosion barriers or mitigation shall be identified for each sub-system so that their effectiveness or compliance status can be assessed during the operational phase.

For each facility the CMP and associated corrosion control documents should define the key parameters that are required to be controlled to safeguard the relevant barriers. The CMP should also identify the relevant performance indicators and the actions that shall be taken by the Principal's operations, maintenance, inspection and materials and corrosion staff if the defined conditions are not maintained.

Further details on the CMP are provided in PTS 30.00.10.39: Corrosion Management.

2.2.4.3 Corrosion Management Framework deliverables

Documentation that describes the materials selection and corrosion management strategy shall be provided to the team(s) responsible for commissioning and operations. This should include:

- Finalised materials selection document;
- Risk Based Assessment (e.g. FMEA) used to identify the integrity threats;
- Corrosion Management Program (as described above and in Appendix 1);
- Populated corrosion and inspection data management database (including line list);
- Maintenance Reference Plan;
- Initial RBI plan and Inspection Reference Plan.

2.2.4.4 Corrosion control and mitigation methods

If corrosion control is dependent upon corrosion mitigation measures requiring operational activity, these shall be documented in such a way that all the requirements and performance checks for the chosen mitigation method, and those responsible for their execution, are clearly defined and made available.

Sphering and pigging

If sphering and pigging of a pipeline or flowline is considered an essential part of the corrosion management approach, a pigging programme with its associated justification shall form part of the required documentation and be noted as an operational responsibility in the appropriate Corrosion Management Program. Pig selection is critical, e.g. brush pigs should be used when pipelines are at risk of bacterial corrosion.

Chemical injection requirements

If corrosion control is to be based on the use of chemical injection (corrosion inhibitor, pH control chemical, oxygen scavenger, or biocide), documentation shall provide details of the process to be followed, the chemical(s) to be used and their concentration(s) in the process stream and the required availability of the corrosion control system. The responsibilities of operations staff for the everyday running of the corrosion control programme shall be highlighted in the CMP, and included in the facility operating procedures. A detailed review of interruptions of chemical injection and their control shall be carried out to demonstrate that the required availability of the inhibitor system can be achieved.

Production Chemistry and OR&A personnel should be involved in the selection of chemicals and defining of treatments.

The key performance indicators of corrosion control systems shall be compiled and reviewed at a frequency in line with the required availability (e.g. 99 % availability: daily review, 95 % availability: 2 weekly review). This information should be rolled up on an annual basis to provide an annualised assessment of the injection system availability. This information is a key requirement for later RBI analysis of the required inspection interval; good control and records can lead to reduced inspection requirements, e.g. reduced intelligent pigging of pipelines.

Gas Dehydration

If corrosion control is based upon gas drying, the required gas dew point shall be clearly defined as a reference point for the responsible operations staff. Operational requirements and controls of glycol systems shall be clearly defined in the corrosion management framework.

Operational process control is of vital importance for the corrosion management of water-dry gas service pipelines that do not have a corrosion allowance. Good records shall be kept and the performance data shall be compiled on at least an annual basis to provide an annualised assessment of dry operation (the drying system availability). This information is

a key requirement for later RBI analysis of the required inspection interval; good control and records can lead to reduced inspection requirements.

2.2.4.5 Inspection and corrosion monitoring

The project documentation shall include proposals for the inspection / corrosion monitoring philosophy demonstrating that the technical integrity of all equipment is maintained during the design life. The proposals shall be fully justified and provide guidelines on frequency and locations of inspections. The need or otherwise for a baseline inspection shall be addressed.

Where measurements require the permanent installation of measuring devices, the types of instruments to be used shall be stated and their locations shall be shown on system drawings. Corrosion monitoring by means of coupons or probes will not give a complete picture of the corrosion taking place in a system and should not be solely relied upon to demonstrate integrity. Plans for inspections to demonstrate continued integrity shall also be made for critical systems.

2.2.4.6 Project data collection and storage in relation to corrosion management

Records of operating conditions, corrosion and integrity related design information, criticality definitions for individual systems, and Corrosion Management Programs should be made available in electronic form. Preferably this information is entered into a database shared with operations staff, from which it can be readily accessed for corrosion management purposes during the operations phase.

2.2.4.7 Plans for feedback

Plans for feedback to management of in-service integrity information, based upon the criticality of the various operating systems, shall be prepared and reported. These plans should reflect the reliability-centred maintenance and RBI approaches that are to be followed.

2.3 MATERIALS SELECTION FOR CAPITAL PROJECTS

2.3.1 General

A high level materials selection, aimed at identifying unusually high cost materials, is carried out during the Assess phase as part of the level 1 (CAPEX & OPEX) cost estimate (+40%/–25%). For main process stream items, initial materials selection is carried out at the Concept Selection phase of a project. Materials selection for secondary process streams is usually carried out in the Front End Engineering Design (FEED) phase. During the FEED, materials selection may be optimised, as more information becomes available, in order to reduce costs to a minimum in line with specific project parameters and risk philosophy. At this stage, more refined judgements on corrosion rates, life predictions, and risk assessments can ensure that the proposed materials will be fit for purpose. For long-lead and/or bulk items (e.g. downhole tubing and line pipe), key materials decisions should be made as early as possible in the project, preferably during the Concept Selection phase, i.e. ahead of FEED. If the new project will make use of and tie into existing installations, the materials in place and their current condition should be ascertained in the Concept Selection phase. Operations personnel shall be included in the project team, or consulted, for these types of developments.

The selection process is structured as a 3-tier system based on:

a) Standard materials selection

Guidance on the selection of technically proven and economically acceptable materials selection for most equipment is given in PTS 39.01.10.12. Selection is based upon the stated information on the environmental conditions for each system. Standard materials selection is used to fill in the details for the systems that do not require materials optimisation. Some optimisation may be required on some process systems, if conditions are encountered that are not adequately covered in this PTS, or if the user wishes to

consider other materials choices, in the interest of potential cost savings. This will generally require justification based on a life cycle cost analysis and a technical integrity verification..

b) **Material optimisation (specialist consultation)**

The materials data used for this optimisation process are included in. These data require specialist interpretation. More complex cases shall be verified on the basis of limitations derived from experience with individual alloys or generic groups of alloys.

c) **Experimental evaluation (specialist consultation)**

Experimental work might be necessary to evaluate materials for specific applications. It shall be carried out in accordance with the material testing methodology selected for the failure modes anticipated. Where this is required to assess the suitability of the lowest cost option, it should be carried out ahead of the as part of the Field Development Plan (FDP).

General guidance on the qualification of materials is provided in PTS 39.01.10.12. Appendix 3.

2.3.2 **Standard materials selection**

The standard materials selection process includes the following steps:

a) **Define the requirements and the environment**

The intended design life of the proposed equipment shall be stated.

The internal and external environments for the equipment shall be defined, including any non-routine or non-operational conditions that might be encountered. The variables characterising of the corrosive environment shall be quantified for normal operating conditions and, to some extent, for unusual or upset conditions.

At this point the operation has to be characterised, e.g. in terms of manning levels, access by operators, capabilities of operators, in-house or contract operated, access to supplies, spare parts availability, etc.

b) **Assess the applicability of carbon steel and define possible corrosion control options**

As an initial step in the material selection process, the suitability of the potentially low cost option involving the use of carbon steel should be thoroughly investigated and evaluated to serve as a baseline against which to compare more corrosion resistant, and possibly more costly, alternatives. Part of this process will involve the calculation of the Service Life Corrosion (SLC) for the proposed operating conditions.

For the carbon steel option, possible corrosion control options to protect the steel from premature failure should be investigated. These could include chemical corrosion control, coatings, cathodic protection and control of process fluids, e.g. pH stabilisation and dehydration. The results of these studies could lead to a lower value of SLC being appropriate. This will often result in more than one corrosion control option being taken forward for further consideration (e.g. carbon steel with a corrosion allowance and inhibition system versus carbon steel with a (different) corrosion allowance and a dehydration system). The availability of these solutions should be taken into account. For example, it is notoriously difficult to achieve a consistently high availability of corrosion inhibitors, so if this is considered, the training and organisational responsibilities should be realised.

c) **Other materials options**

Besides solid corrosion resistant metals, other options should be considered, in particular for pipelines:

- High density polyethylene (HDPE) liners for oil and water service.
- Internal fusion bonded epoxy (FBE) coating for water injection service.
- CRA clad or lined pipe, in particular for very corrosive and sour conditions.
- Glass reinforced plastic (GRP) for water injection, oil and gas production.

d) Make materials choices

Typical materials shall be selected with the aid of the guide tables for each type of equipment (see PTS 39.01.10.12.). While a material included is technically acceptable, it will not necessarily be the most cost-effective choice. This will often lead to more than one technically acceptable material being taken forward for further consideration (e.g. carbon steel with a corrosion allowance versus one or more alternative corrosion-resistant materials).

e) Develop corrosion management framework

In many cases the selection of a corrosion resistant material will not be justified. A lower cost material (usually carbon steel) will be used and this will require the application of corrosion control measures. This requires the development of a corrosion management strategy to ensure that the corrosion is controlled over the lifetime of the facility. This is a critical activity that has to be implemented to safeguard integrity and prevent material failures. A corrosion management strategy should be in place for all equipment, not just for carbon steel items. For example, CRA items selected to cope with internal corrosion may require a strategy to deal with external corrosion.

The deliverable documents underpinning this strategy are the:

- Corrosion Management Program (CMP);
- Maintenance Reference Plan (MRP);
- PETRONAS Risk-Based Inspection (P-RBI) Inspection Reference Plan (IRP).

If the material selected for a given application is fully corrosion resistant under all anticipated operating conditions, the limits of corrosion resistance should be recorded in the Corrosion Management Program for the facility.

f) Assess economics of choices

In the final analysis, selection of the corrosion control option (which includes materials selection) is often an economic decision, assessing the total cost of each alternative over the total life of the system, including quantification of the risks and uncertainties. These include the risk of failure of corrosion control, the economic impact of corrosion control, RBI, sand management, inhibition and the possibility of market changes, whereby certain materials could become more or less economic. Where the risk of failure of corrosion control is high, the consequences should be taken into account, e.g. enhanced corrosion control measures, and enhanced inspection and repair. These will be reflected in the economic consequence of failure, as assessed in P-RBI. Operations personnel should be involved in the life cycle cost assessment to ensure all operating costs are considered. This work shall be completed as part of the corrosion control options selection report and the materials selection report during the Define phase

g) Maintain live documents

The Corrosion Management Program, Inspection Reference Plan and Maintenance Reference Plan are live documents for the lifetime of the facility. These shall be updated whenever there are (approved) materials substitutions (e.g. during procurement and fabrication), changes to the corrosion control system and changes to the operation and process, and as monitoring, inspection and maintenance data are collected during the lifetime of the facility. Service company personnel often carry out this type of data collection. Personnel involved shall be made aware of the importance of this work.

2.3.3 Information required and review of factors affecting materials selection

2.3.3.1 General

Determination of the possible types of degradation and likely rate of metal loss requires an analysis of the corrosivity of the internal and external environments. This section describes the information that is required to make a reasonable evaluation of the corrosion risks and their likely impact. In general, a corrosion allowance will be added only in response to expected internal corrosion. External corrosion is normally controlled by corrosion

protection, comprising coatings and cathodic protection where appropriate. Hence a dedicated “external” corrosion allowance is not normally required (see note below). Coatings usually have life cycles shorter than the anticipated operational life cycle and may require maintenance in order to minimise the threat of atmospheric corrosion (AC) and corrosion under insulation (CUI). Hence, under certain process operating conditions, external rather than internal corrosion might be the dominant corrosion mechanism to be anticipated. An idea of atmospheric corrosion rates can either be obtained from documented data or from API 581, 1st edition, Table N3.

NOTE: Exceptions to this practice of no external corrosion allowance are:
a) The Performance Standard for a coating includes remedial coating repair as an accepted part of the design;
and
b) Management of integrity at inaccessible locations such as insulated pipework and support locations requires patching up of coating after a defined period, e.g. 3 to 10 years.

For both internal and external environments, welds and heat affected zones are critical areas in terms of corrosion resistance (see Appendix 2).

2.3.3.2 Internal environments

(a) Definition of critical operating and environmental factors

Table 1 summarises the information necessary to perform materials selection for commonly encountered environments. The information required for materials selection is shown in the second column, and the additional information required for Service Life Corrosion calculations (for carbon steel) is shown in the third column.

Table 1 Information required for materials selection for internal environments

System	Essential information required for materials selection	Additional information required for service life corrosion calculation
Equipment carrying produced fluids	• type of fluid • presence of free water • mol % CO₂ • ppm H₂S (at known pressure) • pH (estimation of in situ pH and where possible measure the pH) • chloride level (of produced and condensed water) • operating pressure • operating temperature • design pressure • bubble point pressure • design temperature • min. blow down temperature • presence of O₂ or free S (free S can be in the gas or condensate) • presence of bacteria • sand content • project life • ambient temperature • maximum temperature • presence of mercury • water dew point in gas systems • water content of the gas	• the full stream molar composition • whether inhibitors are to be injected • flow regime(s) • flow velocities of all phases • water cut in crude oil systems • water content in glycol (where added for corrosion or hydrate control) • HCO₃⁻ content of water, or preferably, full water composition • concentration of organic acids (C1 – C4) • projected operating pressure and temperature profile over life of project • heat transfer coefficients of coating systems used (pipelines)reservoir type (carbonate or sandstone)
Utility systems	• type of fluid • presence of free water • min. and max. design temperatures • inhibition philosophy • flow rates	
Equipment carrying sea water, including water injection and fire water	• max. service temperature • oxygen content • chloride content • presence of bacteria • stagnant, intermittent or continually flowing • flow rate • concentration of biocide (e.g. hypochlorite and residual chlorine) • operating mode; dry or wet when not in use	• for water injection systems the anticipated amount and particle sizes of corrosion products are often required to manage well sand control efficiency.
Amine containing systems	• amine corrosion • amine cracking	

The following gives additional information to Table 1:

The anticipated corrosion losses shall be calculated for the normal operating conditions as well as other conditions that normally happen during the operational phase, such as interruptions of inhibition (corrosion during the maximum acceptable time that no inhibitor is available), shut-ins, hydrotest, well treatments. See also (2.3.3.6). If a material in the projected service environment could fail by corrosion cracking, the design pressure and worst-case temperature (for the material being considered) should also be adopted to ensure that, if the system operates at the design conditions (even if only for a limited period), there is no risk of corrosion cracking, which can in some cases occur in a matter of hours. If there is a risk of cracking, the use of an alternative material shall be considered.

Alternatively, the corrosive environment, the design pressure and/or the worst-case temperature can be controlled to avoid stress corrosion cracking. If this approach is taken, appropriate Performance Standards shall be put in place in accordance with the Technical Integrity Framework.

The risk of bacterial corrosion throughout the life of the facility shall be considered for all equipment. If there is such a risk, a mitigation strategy shall be implemented. This strategy shall consider the construction, commissioning and operational phases.

In oil wells, the pressure to be used in corrosion calculations should be the 'bubble point pressure' since if the pressure exceeds this value the partial pressure of the gas (which is used to calculate the corrosion rate) does not increase and the gas simply dissolves into the hydrocarbon phase.

In systems containing no free gas phase, the CO₂ and/or H₂S molar concentration to be used is equivalent to the fugacity (similar to the partial pressure, while accounting for the non-ideal behaviour of the gas) that would exist in a virtual gas phase in equilibrium with the aqueous phase in the system.

Oxygen is not normally present in production streams but oxygen contamination can occur if, for example, seawater from open-bottomed offshore sump systems is pumped into the production stream, or in onshore operations if fluids from saver pits are pumped into the production system, or due to inadequate pump or compressor seals, or contamination during pigging operations. The ingress of oxygen into producing systems is an operationally avoidable upset condition and shall not be accommodated in the material selection process; the system should be designed to keep oxygen out. The risk related to the failure to control oxygen should be assessed as part of the FMEA. Oxygen corrosion in aqueous systems, including water flood systems, can be calculated with any suitable corrosion prediction software such as, but not limited to HYDROCOR and ECE4.

Elemental sulphur is found in certain wells and can form polysulphides, which cause high rates of localised corrosion and can lead to cracking. Polysulphides can be transported through the system and cause corrosion problems further downstream.

If a full water analysis is not available, at least the chloride ion (Cl⁻) and the bicarbonate (HCO₃⁻) contents should be obtained. The Cl⁻ content is essential for determining the risk of cracking. The HCO₃⁻ concentration will affect the pH (see NOTE) and therefore the corrosion rate, in particular the CO₂ corrosion rate. Where possible a production chemist should be consulted to check the validity of the data and calculate the pH.

NOTE: pH values can be difficult to measure accurately; this should ideally be done under pressure, and without CO₂ escaping. If the sample is exposed to atmospheric pressure the acid gases are released and the pH measured will tend to be higher than the actual value under operating pressure. For specialized sampling and pH measurement procedures, contact the (local) SME. See also Appendix 3.

At the very least it is necessary to know whether the water phase comes from produced water or condensed water so that reasonable assumptions can be made about the likely chloride content and pH values.

If no other information is available, the following worst case (conservative) values shall be taken:

Gas production environments (produced gas with or without produced water):

pH	3.5
chloride	1 g/L NaCl (condensation water only), 250 g/L NaCl (formation water produced)

Oil production environments:

pH	4.5
chloride	165 g/L NaCl (100 g/L dissolved chloride)