I.Corr CED: Corrosion Control in Transport and Infrastructure

Managing Corrosion in Ageing Offshore Infrastructures

Steve Paterson
Arbeadie Consultants
formerly Shell International

Content

- Operating beyond design life
- Key considerations for ageing facilities
- Corrosion management
- Main corrosion threats and challenges
- Way forward
- Role for I.Corr?

Operating beyond design life

- Many offshore facilities have been operated beyond their design life
- Brent field brought on stream in 1976 – 25 year design life
  - decommissioning started with cessation of production (CoP) of Brent-D in 2011 (35 years service) and Brent-A/B in 2014
  - takes years to abandon wells & prepare facilities for removal (Brent-D in 2017 followed by Brent-B in 2019)
  - still need to maintain essential services and structures
  - Brent-C is still producing mainly oil/gas from Penguins subsea field
  - CoP delayed 12 mths to 2021 because of Covid-19 (45 years service!)
- Other offshore facilities are expected to operate beyond design life
- Many built during CRINE period with limited POB for maintenance
- What lifetime can we expect from structures?

Forth rail bridge

- Opened in 1890
- Original design life?
- Life extension?
- Major maintenance 2002-2011
- Application of 230,000 m^2 of paint at a total cost of £130M
- Paint system expected to have a life of at least 25 years and perhaps as long as 40 years
- Work involved blasting off all previous layers of paint allowing repairs to be made to the steel
- Network Rail estimate the life of the bridge to be >100 years
- Dependent on inspection and yearly refurbishment work programme

Life extension for offshore installations

- A review should be carried out to make the case for continued service of an offshore installation and should include:
  - establish the current condition of the installation and confirm compliance with design and HSE safety regulations
  - anticipate the impact of ageing, obsolescence and other changes that could affect future service
  - predict future production and operating expenditure
  - identify technical requirements essential for cessation of production (CoP) and decommissioning
  - develop plans to address gaps which could limit the service life of the installation or impede decommissioning
- Energy Institute published guidance document for Life extension of offshore installations in 2017

Key factors in life extension

- Establishing current condition
- Availability of :
  - original drawings
  - fabrication records
  - material certificates
- Operational history
- Changes in process conditions and fluids
- Inspection and maintenance records
- Analysis of inspection data
- Expected service life – creep of CoP
- Confidence in assessment of degradation mechanisms
- Maintenance and inspection capability

Implementing life extension

- Assessment of ageing of facilities should be an integral part of the corrosion management process to ensure continued safe operation
- Management of ageing equipment and life extension should be integrated into the existing corrosion management system
- Management of ageing and life extension of facilities requires knowledge and understanding of factors causing materials degradation and maintenance of barriers required to mitigate threats

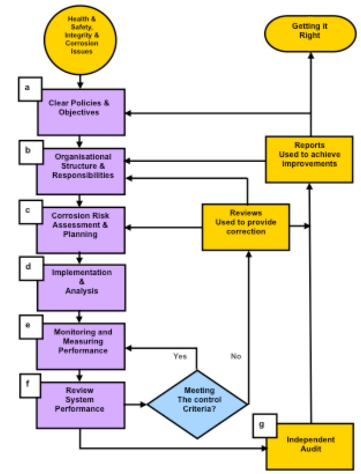


Figure 1. The Basic Corrosion Management Process Model

What is corrosion management?

- What it's not:
  - inspection
  - corrosion monitoring (probes)
  - condition monitoring (sensors)
- Corrosion management is:
  - clear direction and objectives
  - commitment at all levels of the organisation
  - sufficient resources
  - prevention where possible
  - assessment of risk
  - prioritization of activities
  - review of effectiveness
- Energy Institute issued revised guidance for corrosion management in oil and gas production in 2019

Energy Institute guidance

Plan:

- Identify what needs to be achieved to manage corrosion
- Allocate responsibilities for developing and implementing the plan
- Identify key performance indicators to measure the effectiveness
- Consider future corrosion threats

Do:

- Identify and prioritise the potential corrosion threats
- Develop a resource of competent engineers
- Identify the necessary corrosion management systems and ensure implementation
- Maintain the installation and plant to ensure it is safe and economic to operate
- Supervise the activities to ensure the plan is implemented

Check:

- Measure the performance of the corrosion management system against the KPIs
- Investigate accidents and incidents
- Trend the performance of the corrosion management

Act:

- Review/Audit the performance of the corrosion management system

Other Energy Institute guidance documents

Guidance documents issued since 2017 include:

- Assessment of corrosion threats in RBI (2019)
- Caisson integrity management (2019)
- External corrosion of stainless steels offshore (2018)
- Corrosion inhibitors in oil and gas production (2018)
- Corrosion Under Pipe Supports (2018)
- Firewater deluge systems (2018)
- MIC in oil and gas production (2017)
- Sand erosion and Erosion-corrosion (2017)
- Downhole materials (2017)

Key factors in assessment of ageing

- Assessment of corrosion in terms of historical damage and potential future damage are important inputs to corrosion risk assessments
- Changes in process fluids over time or through operational changes (e.g. modifications, new streams) and possible associated changes in corrosivity need to be taken into consideration during corrosion risk assessments
- External degradation through exposure to environment will normally be assessed as part of fabric maintenance strategy
- Condition of plant and equipment and significant changes should be reported through existing Inspection procedures and assessed in regular Corrosion Management/RBI Meetings

Ageing mechanisms and assessment

Time dependent:

- Fatigue: S-N curves
- Corrosion Fatigue: Modified S-N curves
- Creep: Design codes – not normally encountered in Upstream
- Wear: Identify and assess/inspect (eg valves)
- Erosion: Often very high degradation rates – models available
- Internal Corrosion: Various assessment models
- External Corrosion: Wealth of data and some assessment models
- CUI: Prediction capability limited!

Non-time dependent (not feasible to monitor in terms of life extension):

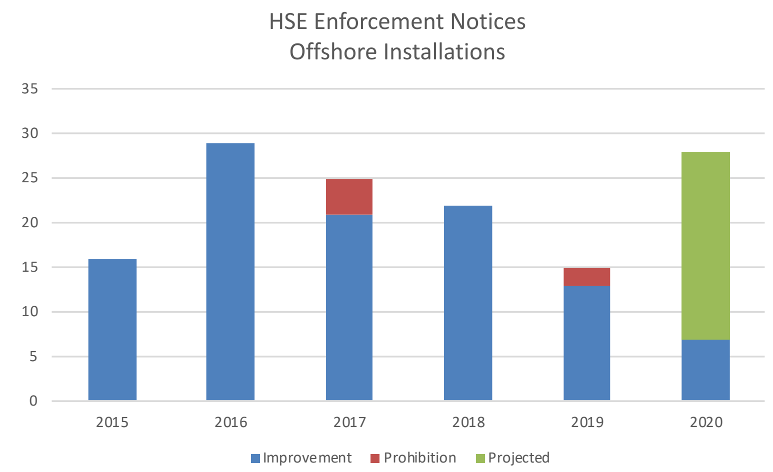
- Stress corrosion
- Hydrogen effects

Responsibilities and communication

- Primary responsibility for assessing the consequences of material degradation in plant and equipment is normally with Mechanical, Structural and Pipeline disciplines
- Materials & Corrosion engineers interface with these disciplines to ensure that threats associated with material degradation are properly managed
- Communication with other disciplines should be through specific Corrosion Management Meetings or wider Technical Integrity Meetings in the Asset
- Verification of assessment of degradation and ageing should be captured by management reviews and audits

Performance monitoring

- Essential to define realistic and transparent KPI's
- Compliance status of barriers to corrosion can be monitored and used to highlight degradation trends
- Annual reporting can be used to give:
  - overall condition of facilities and effects of ageing
  - bring significant issues to attention of Asset management
- Current industry performance?
  HSE Enforcement notices:



Current primary threats

Key current primary threats to facilities/pipelines:

- Fabric degradation – external corrosion
- Corrosion under insulation (CUI)
- Microbial corrosion
- Sand erosion
- Preferential weld corrosion

Mitigation:

- CUI/Fabric maintenance tackled through campaign (barge?) maintenance and focused by better industry guidance
- Corrosion/erosion mechanisms tackled through sustaining existing corrosion management system, monitoring and procedures combined with corrosion awareness campaigns

Effective campaign fabric maintenance

Corrosion Under Insulation

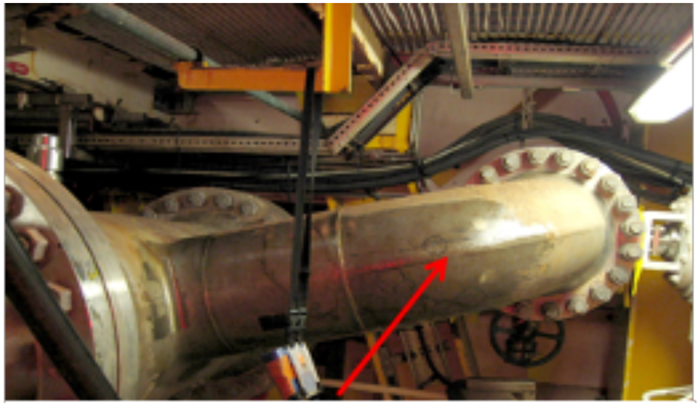
- Still a major issue offshore and onshore
- Stripping insulation for inspection still only effective control method
  Development of NDT techniques? Radiography/PEC
- Increased use of sensors? Corrosion/water detection
- Predictive capability? Need more industry data!

Microbial induced corrosion (MIC)

- Increasing occurrence in offshore facilities
- High corrosion rates are possible (2 to 4 mm/year or even higher)
- Associated with low flow or stagnant conditions e.g. in dead-legs and under deposits

- Limited corrosion rate prediction capability
- Lower flow rates in oil facilities and increasing water cuts
- Environmental impact of traditional biocides

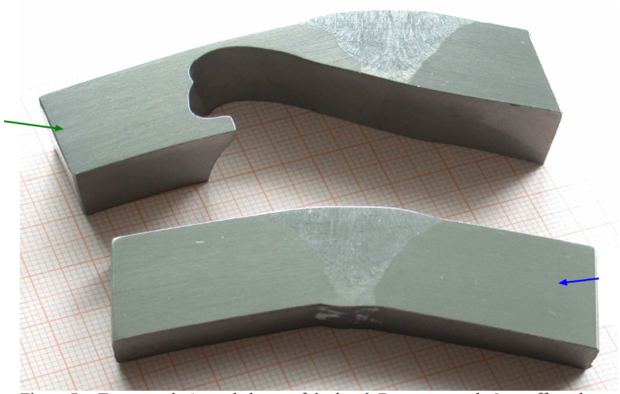
Sand erosion



Leak at bend in 14” 22Cr duplex stainless steel import line

- As reservoir pressures drop gas flow velocities and sand production increase
- Workover of well to reduce sand production less likely
- Erosion by sand will be an increasing issue

Erosion of internal wall by sand



Cross section of bend 20 mm thick showing eroded area

Preferential weld corrosion

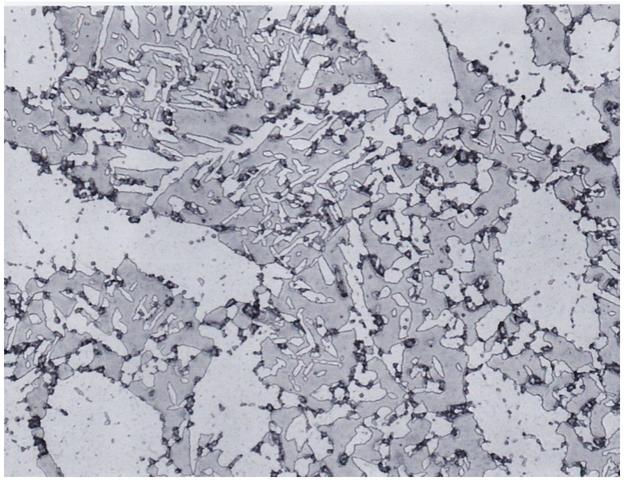
- Use of nickel in welds was introduced in late 80's to reduce preferential weld corrosion in water service and increase toughness
- Practice also adopted for hydrocarbon service

- Many cases of preferential weld corrosion of nickel containing welds in hydrocarbon service
- Mechanism not fully understood (effect of other elements?)
- Use of hybrid welds can be used to reduce risk
- Effective corrosion inhibition most common approach to reduce risk
- Suitable corrosion inhibitors with reduced environmental impact will not be as effective

Future challenges

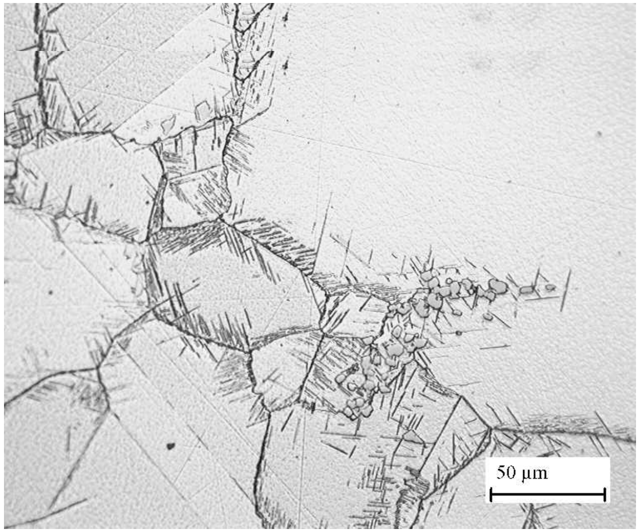
- Impact of Covid-19 on the infrastructure – how much will close?
- Continuing Regulator scrutiny
- Sustaining maintenance programmes on facilities
- Sustaining corrosion inhibition application
- Effectiveness of new chemicals ("green inhibitors")
- Monitoring of degradation (corrosion/erosion)
- Inspection of inaccessible areas in facilities
- Assessment and inspection of pipelines and flexible pipe
- Potential for CRA failures
- Sustaining competence

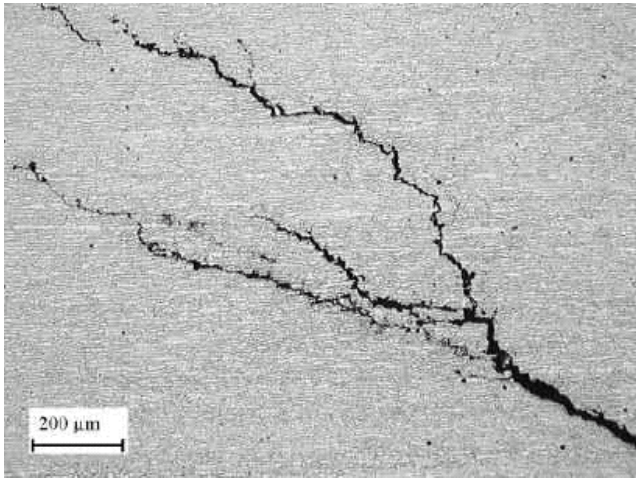
Exotic materials – exotic failures



Wider use of CRA's can mean more exotic failures:

- Widespread instances of failure from sigma phase in duplex stainless steels
- Alloy 718 tubing hanger failure due to delta phase in HPHT well
- Chloride SCC of duplex stainless steel in HPHT facility
- HISC of duplex stainless steel subsea





Key factors for sustaining competence?

- Ageing materials & corrosion engineering population
- Retention of knowledge of facilities
- Availability of experienced corrosion engineers
- Difficulty in attracting new graduates
- Attracting students to materials university courses
- Expectations of new graduates - retention
- Accelerated competence development – “time to autonomy”
- Knowledge transfer from experienced staff
- Wider implementation of I.Corr certification schemes

Way forward

- Use existing corrosion management systems and practices including industry guidance
- Extend maintenance capability - access / productivity / strategies
- Anticipate service life creep and adapt maintenance strategies for end of field life
- Develop understanding and gather data for ageing facilities to reduce uncertainties in assessment methods/models
- Use new technologies for mitigation and inspection
  - surface tolerant paint systems
  - wireless monitoring sensors / leak detection capability
  - non-intrusive inspection & intelligent pigging
- Promote materials, corrosion & inspection as a discipline
- More active involvement by I.Corr in university corrosion courses?

Thank You!