I. Corr CED: Corrosion Control in Transport and Infrastructure

Managing Corrosion in Ageing Offshore Infrastructures

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Content

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• Key considerations for ageing facilities
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• Main corrosion threats and challenges
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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 m² 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
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:

![HSE Enforcement Notices](Image)
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

- 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

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!