Subsea Integrity Management: Materials Selection & Monitoring

Development of an integrity management program is initiated during design phase, which includes selecting the appropriate materials, establishing requirements for corrosion, erosion, flow assurance and process along with associated maintenance, monitoring and surveillance requirements. In this GATEKEEPER, the philosophy around the materials selection and corrosion monitoring is discussed as the primary design barrier to corrosion and cracking in critical parts of a subsea system.

Corrosion Prediction in Subsea Systems

Corrosion and materials engineers often rely on corrosion prediction models to select appropriate materials for construction, incorporate sufficient corrosion allowance into a design, and establish the need for chemical corrosion inhibitors or other corrosion mitigation methods. However, there are nuances in the way each corrosion model applies the input parameters to predict corrosion rates. Correct interpretation of corrosion model predictions requires an understanding of these nuances. It is important for users to understand the parameters and design constraints behind each model in order to accurately assess the corrosion modeling results before making recommendations. You can read more about the nuances of corrosion modeling in the Corrosion Modeling - Influencing Factors GATEKEEPER GAT2004-GKP2014.02.

Most corrosion models are unable to account for any conditions other than the corrosion of carbon steel due to CO₂. Other corrosion mechanisms that may increase or interfere with CO₂-induced corrosion are not considered. These include the presence of H₂S, elemental sulfur, or oxygen; materials of construction other than carbon steel; erosion by solids or liquid impingement; synergistic erosion/corrosion behaviors; microbiologically induced corrosion (MIC); under-deposit corrosion; scale deposition; localized corrosion, crevice corrosion, or pitting; and galvanic corrosion.

Corrosion in a CO₂-Containing Environment

Corrosion control techniques and methodologies for CO₂-induced corrosion are well established and do not require extensive discussion. Carbon steel with corrosion allowance is typically used to manufacture flowlines, where corrosion is controlled through the use of an appropriate corrosion inhibitor (CI) that has been tested to deliver an acceptable effectiveness in the exposure conditions in which it will operate. Additionally, biocide dosing may be required, as well as pigging of production systems may also be undertaken on a sufficiently regular basis to stop significant build-up of water and/or solids that would otherwise increase the corrosion rate. Corrosion probes should also be placed at the best available locations to allow regular monitoring of corrosion rates.

Corrosion may also be controlled through the use of Corrosion Resistant Alloys (CRAs) as the materials of construction or as clad from subsea structures. The alloy chosen must have a proven track record in the specific conditions (CO₂ concentration range, temperature, pressure, chloride content, oxygen content, etc.). However, the use of a CRA outside of well tubing and specific processing equipment is usually discounted due to its high capital cost.

Corrosion in a CO₂ & H₂S-Containing Environment

H₂S cracking-resistant carbon steel, as defined by standard ISO 15156-2, is normally used as the flowline material of choice where the partial pressure of H₂S is reasonably anticipated to exceed 0.05 psi (3.45 millibars) during the life of the development. General guidance on the use of CRAs for sour service is provided below. CRA alloys are generally not used for flowline construction due to cost considerations, but experience in their use does exist:

- Martensitic stainless steels can be subject to cracking in sour conditions as a result of the presence of H₂S. They may also suffer from cracking under sweet conditions, particularly at welds.
- Austenitic stainless steels – Type 316L is widely used above present ISO limits on sour gas processes, particularly where chloride contents are low or where pH is high. However, both stress corrosion cracking and crevice corrosion may become an issue in the presence of chloride.
- Duplex 22% Cr and Super duplex 25% Cr stainless steels have shown satisfactory corrosion resistance in sour conditions up to H₂S partial pressures of 1.5 psi and 3 psi, respectively.
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- Super-austenitic stainless steels, materials such as 28% Cr – 31% Ni, or higher, have proven fully adequate corrosion resistance to severe sour environments, both from laboratory and field tests, as long as no sulfur deposition is expected. These materials are not reputed to be corrosion resistant to sulfur combined with chlorides.
- Nickel alloys can provide corrosion protection when sulfur deposition is expected. The exact alloy material chosen must be made with careful consideration of operating temperature, chloride content, CO₂ and H₂S contents to minimize risk of stress corrosion cracking.

Specifying Corrosion Inhibitor Injection Locations Subsea

Injection of corrosion inhibitor subsea is dependent on the type of material used downstream of the injection point. The qualified corrosion inhibitor providing adequate protection to the downstream carbon steel structures can be applied at three main injection locations: injection downhole, injection at the tree and injection at the manifold.

Injection Downhole

Injecting corrosion inhibitor downhole ensures that equipment from the well up is protected. Injecting downhole increases costs due to the need for high pressure pumps and equipment topsides. Plus, a loss of a downhole injection point is extremely costly to remediate.

Wells designed with CRA tubing and trees will not see any additional value associated with downhole corrosion inhibitor injection compared to application of the tree.

Injection Location at the Tree

Corrosion inhibitor injection at the tree is typically made downstream of the production choke so that the pumps and injection system can be operated at a lower pressure than if injection is made upstream. This approach requires all components to the flowline jumper to be manufactured from CRA.

However, inhibitor application at the tree is undertaken to protect points downstream of the manifold, as adequate mixing of inhibitor is unlikely to occur before this, and so CRA materials would remain necessary between the tree and manifold.

This approach provides significant redundancy to the corrosion inhibitor delivery system.

Injection Location at the Manifold

The injection of corrosion inhibitor at the manifold requires that all components to the flowline are manufactured from CRA and, depending upon the level of anticipated inhibitor mixing, that the initial section of flowline is internally clad with CRA.

In the case of high inhibitor availability requirement, the need for inhibitor injection at the tree, coupled with the selection of CRA for the tree internals, wellhead jumpers and manifold internals is suggested. Unlike manifold injection, this provides suitable redundancy if an individual injection line becomes unusable for any reason.

Corrosion in Export Gas Lines

The benefit of having a corrosion allowance is that it introduces an additional safety margin beyond the wall thickness dictated by code. It also serves as a mechanism to drive effective dehydration control by the facility as it provides a clear target to be attained in terms of dehydration excursions and total system availability, based on the assumption that general corrosion will occur. However, this comes at an additional material cost and hanging weight, while providing little additional protection against through-wall pitting.

The decision on whether or not to apply a corrosion allowance for the riser may be made based on the expectation of whether corrosion will be localized (no corrosion allowance) or general (1mm corrosion allowance) in nature. This can broadly be determined by assuming that CO₂-induced attack may occur as either generalized or localized attack in a system without corrosion inhibitor, whereas attack in systems using corrosion inhibitor will be in the form of localized corrosion. Figure 1 outlines the decision process for export gas lines.

Monitoring Corrosion Subsea

Monitoring of subsea systems include:

- Subsea corrosion monitoring installations.
- Topsides corrosion coupons and electrical resistance probes applied to the incoming flowlines.
- Routine produced fluid analysis and bacterial monitoring to ensure that changes in system corrosivity do not occur without being detected (changes in produced water composition, decrease in corrosion inhibitor residuals, etc.).
- Maintenance pigging of the subsea flowlines should be accompanied by a sampling program to capture and analyze returned water and solids.
- Develop a recommended corrosion allowance for the subsea flowlines, taking into account the design life.

Conclusion

Corrosion control techniques and methodologies for lines containing both CO₂ and H₂S are similar to those used in flowlines with CO₂ only, although the treatment regimes will vary dependent on specific fluid conditions for the type of inhibitor(s) and biocide(s) added and the prevailing pigging requirements.

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References