



Getting the green light



CHALLENGE

Our client is developing a new subsea gas field to meet the increasing demands from its local and global LNG markets. They needed to know if their existing 30-year-old pipeline could meet code requirements and be safely updated to a higher MAOP to handle the increased gas flow.

PII's comprehensive analysis capabilities pave the way for a 25% increase in the current MAOP to handle increased flow from a new offshore development

Challenge

Our client is developing a new subsea gas field, and asked us to assess the suitability of its existing 30-year-old transportation pipeline for operating at an updated pressure to meet the demands for the increased gas throughput.

While the pipeline has never operated at more than 74% of its original maximum allowable operating pressure (MAOP) at design, the proposed project required a 25% increase in the current MAOP, which was still within the original design parameters. Our job was to identify any 'show stoppers' that could challenge the technical or financial justification for updating the line.

Solution

We conducted a comprehensive feasibility study with a planning horizon of 20 years. Our scope included assessing the operability and integrity of the pipeline at both the current and proposed MAOPs, and determining its upper limit.

Location class assessment

From an environmental and population-risk perspective, the pipeline was designed for Location Class 1 and 2 areas. We found that, although three decades have passed since its construction, significant population growth has occurred around only 5% of its entire length, resulting in a change to Location Class 3 for those areas. Although further population growth could result in several more areas being reclassified as Class 3, none of the areas are likely to change to Class 4 in the foreseeable future. The proposed MAOP is within the upper limit of current Class 3 regulations.



SOLUTION

Our feasibility study included data collection and compliance review, population and location class assessment, integrity and corrosion growth assessment, crack susceptibility review, quantitative risk analysis and input on technical procedure for the pressure increase.



BENEFITS

The existing pipeline was found to meet ASME B31.8 requirements for the required updated pressure, and was shown to be fit-for-purpose. Thus, the client can avoid the high expense of building a new cross-country pipeline to transport the increased gas throughput.

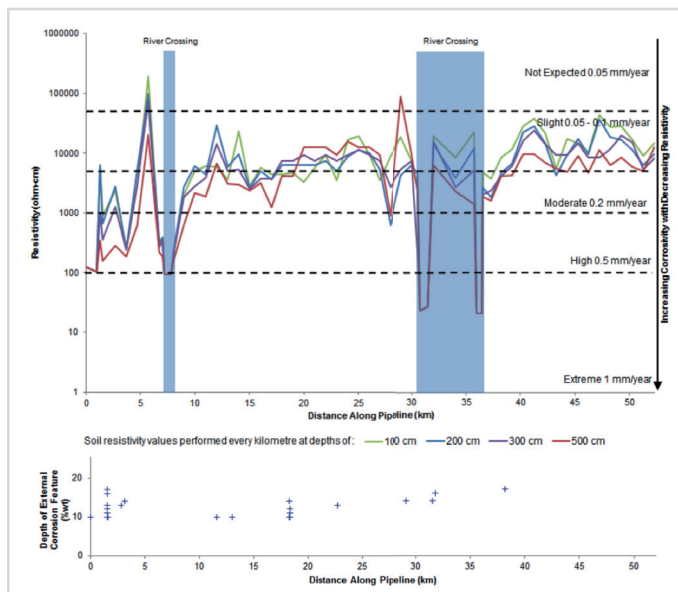
Integrity and corrosion growth assessment

Using theoretical models and published guidance, we determined corrosion growth rates through a comparison of third-party data from 2008 and 2014 in-line inspections (ILI).

Our analysis indicated that the reported internal anomalies were unlikely to be active corrosion sites, but instead mill-related damage or pipe-surface roughness. We also found that sizing differences between the two data sets were not corrosion growth, but in fact caused by tool detection errors and missed features because of the 2008 inspection's low reporting threshold. We concluded that there was no indication of repairs needed within the next 20 years.

Similarly, our data analysis found no evidence of real external corrosion growth between 2008 and 2014. While there was possible minor corrosion growth for isolated features, all were below the threshold rate. This meant there is no need to increase the current re-inspection interval of six years, and that there would be no need for repairs within at least nine years.

The only integrity action we recommended was for a dent we identified that could have been caused by third-party damage, and should be investigated before the pressure is increased.



With the exception of the river crossings, the highest growth rates (up to 0.5 mm/year) are expected in the first 5 km, which have unprotected steel (NACE). For the majority of the pipeline, however, growth is likely to be slight/moderate (0.05 to 0.2 mm/year).

Crack susceptibility review

Since uprating represents a time of particular concern for potential cracking defects, we conducted our fatigue assessment according to both ASME B31.8 and IGE/TD/1 criteria. With each approach, the threat from fatigue was shown to be negligible at both the current operating pressure and the proposed uprated pressure. There was therefore no requirement for more detailed fatigue analysis.

geoilandgas.com/pii

Various forms of stress corrosion cracking (SCC) can occur in pipeline steel that is under stress in a corrosive environment. Contributing factors can include pipe material, loading, coating, CP levels, fluctuating stress, environment, and high temperature. This pipeline has a coal-tar enamel coating that's remained in good condition for over 30 years, with very few coating defects and a well-maintained CP. The operating temperature was not high enough to cause premature coating breakdown or trigger SCC, and the level of pressure cycling is negligible under both the current and proposed regime. All factors considered, there was no conceivable threat from SCC.

For ductile fracture propagation, the current edition of ASME B31.8 requires fracture control by specifying adequate pipe ductility or using crack arresters to stop propagating cracks, which may not have been a code requirement when this pipeline was constructed. It's not known if toughness levels were specified at the time, and there's no toughness data readily available now. We therefore recommended an investigation about the mill specifications to demonstrate toughness, or a Charpy toughness test on line pipe material samples to demonstrate that it does indeed meet the required toughness levels.

Quantitative risk assessment (QRA)

Although QRA is not required by ASME B31.8 code, the client wanted to leave no stone unturned in its quest to ensure the pipeline's integrity and safe operation. Our QRA approach included internationally accepted methods and criteria, and was consistent with the client's QRA requirements defined for the associated offshore field development.

Threats from internal and external corrosion, and from fatigue crack growth, were already shown to be negligible. So we moved on to review failure frequency data from EGIG, UKOPA and CONCAWE – concluding that the primary threat to this pipeline would be a rupture release from external interference damage. Since control of external interference is influenced by surveillance of the pipeline route and notification of work in the vicinity, we recommended increased surveillance frequency, which was supported by a cost-benefit analysis considering both financial and societal/individual risk reduction.

Benefits

The study was completed in under 20 weeks by a team of four PII Integrity Engineering specialists collaborating with two contractors and the client's operational staff.

We determined that, according to the code, the MAOP upper limit is slightly higher than the proposed uprated pressure, and that the pipeline meets ASME B31.8 requirements for operation at the new pressure. We also provided guidance for development of technical procedures and preparatory work, including due diligence activities such as comprehensive documentation; pre and post re-inspection schedules; a two-step pressure raising procedure with a requirement for patrols, leakage surveys, technical and safety approvals before, during and after each pressure increase.