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Replacement of a main oil line based on an integrity-assessment program
by Mohamed Kamal Kabbaj
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Introduction
ADMA-OPCO produces oil from an offshore field in the Arabian Gulf, from where the oil is transported to an export terminal through a subsea pipeline system comprising a 30-in main oil line (MOL), a 24-in loop, and a 22-in spur line (see Fig. 1). Condition monitoring for the 30-in MOL revealed severe and widespread internal metal loss, together with hydrogen-induced cracking (HIC). This condition has increased the risk associated with operating the pipeline to an unacceptable level, dictating replacement of the pipeline on a short-term basis.

The objective of this paper is to describe the integrity-management activities leading to the decision to replace the pipeline, and the corrosion-mitigation measures put in place to control operational risk until the pipeline is decommissioned.

Pipeline description
- year installed: 1967
- OD: 30in
- pipe material: API 5L X52 longitudinally-welded
- wall thickness: 12.7mm (3.05in) (no corrosion allowance)
- length: 54 miles
- design pressure: 1170psig
- max. operating pressure: 600psig (after derating)
- operating temperature: 59-89°F (15-32°C)
- \( \text{H}_2\text{S}/\text{CO}_2/\text{water content: } 0.36%/0.66%/3\% \)
- water depth: 40-110ft
- pipeline stability: the pipeline was laid on the seabed and was stabilized with a thick circular concrete weight coating with open field joints.
- design life: 30 years
- external corrosion protection: the pipeline’s external surfaces were protected with a coal-tar enamel coating, and sacrificial zinc anodes were installed at each field joint.
- special fittings: two 16-in branches were installed and originally blanked off at 6.5 and 30 miles from platform A (PA). The first branch was used later in 1976 to connect the 22-in spur line originating from platform B (PB).
- pigging facilities: the pipeline was not originally designed for any pigging operation. In 1995, modifications were carried out to install launching and receiving facilities suitable for running cleaning and intelligent pigging tools.
- operating history brief: the pipeline was operated since 1967 to transport the whole field oil production. When the 22-in spur line was commissioned in 1977, part of the field production was routed through PB which reduced the flow rate in the pipeline’s first 6.5-mile section. Fluid velocity in this section has been low since 1982, resulting in severe corrosion at the six o’clock position due to water segregation. The pipeline was operated...
Introduction

A comprehensive joint industry program of work has been undertaken by BG Technology, BP Amoco, and Shell Global Solutions bv to investigate the properties and use of high-strength steel line pipe of grade X100 for the construction of pipelines. The program of work included extensive mechanical and metallurgical testing to characterize the materials, together with tests to assess their field weldability and the properties of weldments. The test work was supplemented with studies on defect/damage tolerance, evaluation of the cost benefits of using the product, and contractor studies into aspects of pipeline construction.

For major large-diameter oil and gas pipelines, the trend during the 1980s and 1990s has been towards extensive use of modified grade X65 and, more recently, X70. This trend has been promoted by the developments of leaner composition steels using thermo-mechanical controlled processing (TMCP) of steel plate for pipe, giving a uniform, tough, fine-grain microstructure throughout its thickness with high weldability. This natural progression to higher-strength materials has led to a few pipelines being installed in Europe and Canada using submerged-arc-welded pipe of X80 grade. The prospect of longer-distance pipelines to export gas from remote developments has led operators to consider that even higher-grade steels may offer further cost savings. The current JIP is the result of this perceived need with a targeted specified minimum yield strength of 100ksi (689MPa).

To maximize the economic benefits, the implications of using the materials on an optimized pipeline system design need to be assessed at the concept stage; however, incremental gains can be achieved throughout transportation and construction due to the advantages of using lighter, thinner, higher-strength pipe.

The new materials pose a number of technical challenges with implications in all aspects of design and construction. A number of these implications are reviewed in this presentation, which is one of a series of technical papers to be presented to the pipeline community covering...
SNAM operates a 18,000-mile gas pipeline network and related facilities in Italy. Pipelines vary in age from recent construction to more than 50 years. Most of the high-pressure, long-distance transport pipelines are piggable.

Pipelines are one of the safest and more efficient forms of transporting energy. However, they can be damaged during construction and operation, and are susceptible to time-dependent deterioration. The management of these assets requires continued integrity assurance of the aging system. Periodic maintenance is required to ensure efficient operation of the network. Condition monitoring of this pipeline network is conducted using periodic intelligent pig inspection (to monitor corrosion development), cathodic protection (CP) surveys (to determine the effectiveness of the corrosion-protection system), aerial and above-ground surveillance (to monitor third-party interference activities), and geological surveys (to prevent ground movement).

The many thousands of miles of high-pressure pipelines installed require optimum utilization of available resources in order to operate continuously with the least capital investment and the lowest operating costs. In order to face pipeline aging, gas companies have set strategies aimed at:

- maintaining high level of safety, environmental protection and reliability;
- reducing maintenance costs.

At present, SNAM’s pipeline network, as described in Table 1, is subdivided in two main classes: the primary system, characterized by high-pressure and large-diameter pipelines, and the secondary network, in which all the connecting small-diameter pipelines are grouped. Most of the pipeline system is operated at pressures higher than 350psi.

**Strategies for integrity**

The network consists of pipelines characterized by different age and coating conditions.

As other pipeline operators have done, SNAM has adopted a pipeline-protection and condition-monitoring strategy aimed at ensuring the fitness-for-purpose of the gas-transmission network in the safest and most cost-effective manner.
Time to change?
by Dr Phil Hopkins
Andrew Palmer and Associates (part of the Penspen Group), Newcastle upon Tyne, UK

1 Introduction

We hear a lot about the new economy and new pipeline technologies, and it is our expectation that they will make our industry both more efficient and successful. However, their success is critically dependent on how our industry is managed, staffed, and financed, and therefore they will not be the only means that will cause change in our industry. We are like any other modern industry, and we are undergoing massive commercial and managerial changes that will influence our future more so than technological change.

These changes are brought about by external influences such as unstable oil prices and large oil companies merging. All executives and managers in the pipeline business should appreciate both the changes we are going through, as well as those expected in the future, in order to ensure both personal survival and a healthy pipeline industry.

This article focuses on the ‘change’ we are seeing in our industry, and the change we can expect, and need. It briefly covers new technologies needed in the pipeline industry, but concentrates on the changes we can expect from the market, staff, and management.

2 Recent and future changes in the oil and gas business

The last 30 months have seen significant change in our industry. Two factors that have received the most publicity are:

- mergers of the majors
- the price of oil.

These have direct effects on the new pipelines being built and the approach of operators to existing pipelines. In simple terms, a low oil price means that fields are not viable, and hence pipelines are not built, and big company mergers cause unrest and uncertainty in those companies that make the decisions to build and operate the pipelines.

2.1 Mergers of the majors - pros and cons

Mergers are the modern way of growing a

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1 ‘Majors’ is industry jargon for the largest oil companies in the world - see Table 1.
The Transitgas pipeline project

In 1974, the Swiss section of the North Sea-Italy pipeline was put into service. This so-called Transitgas pipeline crossing Switzerland from north to south is about 130 miles long, with a diameter of 34-36in, and includes one compressor station, 16 valve stations, and about 19 miles of tunnels. The increasing demand for natural gas, and the resulting new contracts, made it necessary to provide a transport system for an additional 90Bcft of natural gas yearly from North Europe to Italy. The Italian natural gas company SNAM SpA decided to expand the Transitgas transmission system by building a new pipeline from the North Sea to Switzerland, and by partly looping and partly replacing the existing Transitgas pipeline. The Swiss section of this project includes 116 miles of 36-in and 48-in pipelines, with a design pressure of 67 or 75bar (972 or 1088 psi) (Fig.1).

In addition to the transmission pipeline, the compressor station will be expanded from 26MW to 60MW, and several valve stations are to be improved or reinstalled. A special feature of the Transitgas pipeline is the large number of tunnels (12 existing tunnels and four tunnels - ranging from 0.3-3.8 miles in length - which have to be constructed), covering 23.75 miles. The longest tunnel - the Grimsel-Stollen - is 12.2 miles long, and crosses the Alps under the Grimsel pass.

The project is managed by Transitgas SA, a company owned by Swissgas AG and SNAM SpA. For the Swiss section, Snamprogetti SA has been contracted for project engineering, with SKS Consulting Engineers Ltd responsible for environment and safety engineering. Total investment in this section is expected to reach approx. $548 million; project planning started...
The 10-in x 16-in Norne Heidrun pipeline in the Norwegian sector of the North Sea presents a considerable challenge in terms of pig development for both pre-commissioning and operations. Provision of a pig for this duty involves:

- a pig design which can operate effectively and safely in both a 10-in line and a 16-in line;
- a sealing system design which can overcome compression set in the 10-in pipe in order to recover and provide sealing in the 16-in line;
- a pig design that can negotiate tight bends, a Y-piece, and other in-line features.

Buckle inducers are used for efficiently folding the 42-in seals into the 28-in line. Correct selection of seal geometry and properties allows the seals to buckle when required and recover sufficiently from compression set.

Fig.2 shows a schematic diagram of Statoil’s Norne Heidrun 10-in x 16-in pipeline. From the Norne FPSO, a 2700-ft 10-in flexible riser runs to the seabed, at a depth of 900ft. On the seabed, the pipeline expands to 16in after the riser termination hub; 55ft downstream from this point, there is an asymmetric 16-in equal Y-piece for possible future tie-in or subsea launch of an inspection pig. From here, the line runs for 77.5 miles, where it ties into the Asgard transport gas export line along with the 16-in pipeline from Heidrun.

The dewatering pig train consists of four pigs run with a glycol batch between each and a trailing final pig run in dry air or nitrogen, Fig.3. As the final pig exits the 10-in flexible and enters the 16-in line, a potential problem arises. Due to the sudden drop in friction, the pig will accelerate suddenly to a relatively high velocity. Such acceleration can cause the pig to
A method for calculating the corrosion allowance for deepwater pipelines and risers

by Dr John Smart
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Estimating a corrosion allowance for deepwater risers is an essential part of their design. Sufficient additional wall thickness must be provided to resist corrosion under realistic conditions of corrosion, with sufficient contingency to cover system upsets and failure to deliver sufficient corrosion inhibitor to the flowline to prevent corrosion. A new procedure is used to estimate wall thickness requirements for risers based on the availability of corrosion inhibitor in sufficient concentration to produce low inhibited corrosion rates. Application to deepwater risers is discussed.

Recommendations

1. Determination of the corrosion allowance for deepwater risers should be made using the corrosion-inhibitor availability model reflecting actual corrosion-inhibitor performance and realistic inhibitor availability, rather than arbitrary inhibitor effectiveness criteria.

2. A potentially-rapid corrosion area exists at the beginning of deepwater risers where rapid cooling and high water condensation rates will occur.

3. Deepwater riser corrosion inhibitors should select methanol-soluble inhibitors capable of adequate performance under high velocity conditions, and which are able to be delivered dissolved in the methanol used for hydrate control.

4. When the inhibitor-availability model indicates that a riser has high risk for corrosion failure, use of corrosion-resistant alloys (CRAs) should be considered.

Introduction

There are now numerous existing and prospective deepwater oil and gas projects in the Gulf of Mexico that must be produced through flowlines located in deep, cold, water. Frequently, the flowlines are very long, running several miles from subsea completions to remote production facilities. There are several internal flow complications in the cold high-pressure environment, including hydrates, paraffins, asphaltenes, and corrosion problems. In addition, delivery of chemicals to these locations sometimes involves long-distance transport of treating chemicals to the point of injection. Methanol or other thermodynamic hydrate inhibitors must be injected to maintain flow under cold, high-pressure conditions, and any corrosion-control chemicals must be compatible with the hydrate inhibitor as well as the other treating chemicals.