DRAFT

A 'lifeline' for pipelines

Kevin Cato, Insitu Pipeline Systems, USA, provides an example of insitu pipe coating giving new life to an ageing pipeline.

During the early 1990s, a major oil and gas company with operations in Southeast Asia began to experience leaks in some of its main offshore pipelines. The pipelines were transporting a heavy paraffin based crude oil, with a high water cut. The top of the pipe had been protected from the inhibiting effect of the wax, while the bottom of the pipe experienced a great deal of channel corrosion and pitting.

Although the company had always made substantial efforts to maintain a safe operating system and avoid any environmental impact due to a leaking pipeline, production and revenues had significantly depleted over the years and pipeline replacement would simply not be the most economical solution to the leakage problem. With this in mind, the company began to explore methods of rehabilitation and insitu coating quickly became its primary focus. This was because many miles could be coated, without cutting or segmenting the pipeline. As a pilot project, the company selected a 12 in., 7.6 mile pipeline that was installed between two offshore platforms.

Insitu Pipeline Systems (IPS) was selected as insitu coating applicator and began test procedures to find a suitable coating that would not only hold up well in the severe service, but would also be conducive to the insitu 'pig applied' method of applying the coating. The following checklist was used in the selection of the coating:

- Chemical and abrasion resistance of coating film.
- Surface preparation and accessibility.
- Film thickness: continuity and quality depending on skilled application.
- Design of equipment.
- Physical abuse, abrasion, liquid velocities and impingement.
- Thermal shock: cyclical heating and cooling.
- Temperature limits and operating characteristics.

The foregoing information, together with guidelines from both successful and failure field histories, narrowed the field to just a few generic types of coatings from which one was selected: Sigma 3445. The coating has a pot life of approximately six to eight hours, providing ample time to pump the batch coating into the pipeline, run the length of the pipeline and recover the excess coating at the receiver.

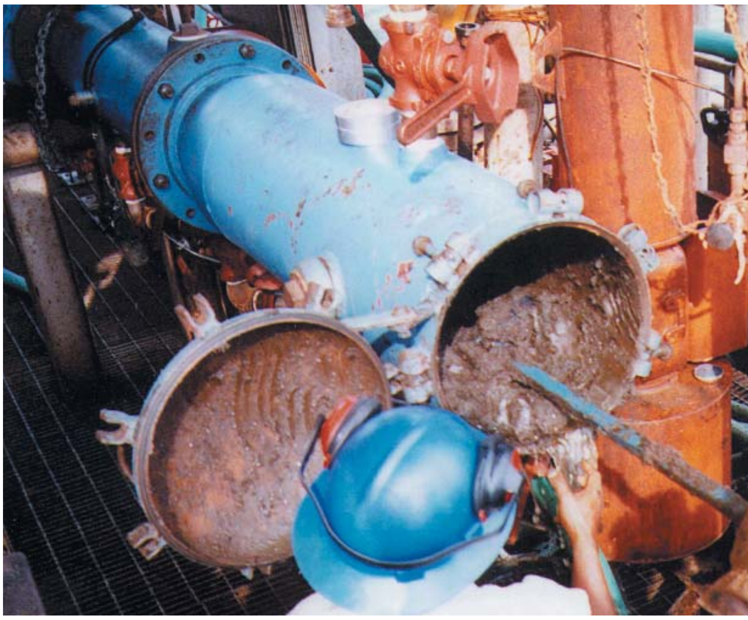

Figure 1. Removing the wax from inside the pipeline.

Chemical cleaning

Surface preparation is the most critical aspect to the success of the insitu coating process and the surface must be cleaned to a minimum of NACE 2 (near white). The chemical cleaning procedures for this project were developed to include a worse case scenario, assuring that the bottom of the pits would be cleaned as well as the pipe wall. Procedures were established to deal with the total removal of all deposits and scales, including paraffin, residual hydrocarbons, iron sulfide and iron oxide scales.

Prior to presenting the pipeline to IPS, the company displaced the product with seawater, and carried out an eight hour hydrotest.

Figure 2. The pipeline once it had been cleaned.

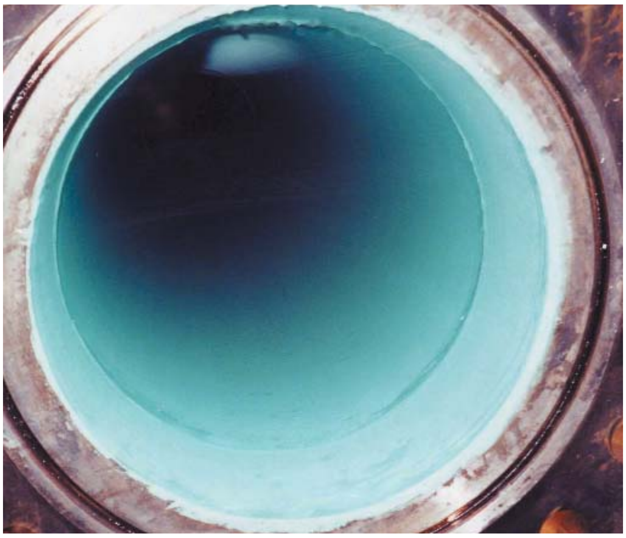

Figure 3. The pipeline once it had been insitu coated.

- The chemical cleaning process began by displacing the seawater from the line. Paraffin solvents were batched between bi-directional pigs to soften and remove all traces of paraffin.
- A detergent was batched between two foam brush pigs to wash the surface of the pipe wall and remove any remaining hydrocarbons and loose deposits. Samples of the effluent were collected at the receiver, tested for solid content and viewed with a black light to determine the presence of hydrocarbons. The line was then flushed with fresh water to remove any trace of detergent.
- Hydrochloric acid (HCL) was batched between two acid resistant pigs, at a concentration of 15 - 25%. The acid strength was verified by titration before it was loaded into the launcher and tested again when the batch arrived at the receiver. After running several batches of HCL, samples were collected and indicated that the acid strength had no longer depleted and the solid content was negligible. Based on this information, the line was considered clean.
- A 5% phosphoric acid solution was batched as part of the final cleaning phase. The phosphate treatment began the passivation process and subsequently aided the coating in producing its maximum adherence to the pipe wall.
- An inhibited water solution was batched to buffer the low pH of the pipe wall and to insure that the residual chloride content was less than the specified 300 ppm. A sample of the batch was collected at the receiver, indicating that the specification had been achieved.
- A batch of methanol, followed by a batch of MEK, was run to ensure that all moisture was sufficiently removed from the pipe wall. This final drying phase required a dry air purge until the dew point at the outlet equaled the dew point at the inlet. General specifications require that the inlet and outlet dew point should be a minimum of 10˚ below the substrate temperature. However, on this project, a dew point of < 0˚ was achieved.

Insitu coating

The coating was pumped between two specially designed pigs that were positioned at the launcher of the pipeline. The coating pigs, manufactured by Ura-Flex Manufacturing, had been modified prior to loading the pigs into the launcher. Modifications to the pigs included the proper sizing of the extrusion rings of the pigs and drilling a series of holes through several of the pig's discs to facilitate the flow of coating to the extrusion ring.

The specifications for this project required a final dry film thickness (DFT) of 8 - 10 mils. The first coating run had a targeted mil thickness of approximately 2 - 3 mils (DFT). The drying time between each coating run was 16 - 24 hrs, with the variance to the drying time being based on the pipeline's subsea temperature and thickness of the applied coating. The movement of the coating batch was controlled by the differential pressure exerted to each end of the batch, with the run speed typically in the range of 8 - 10 ft/s.

To complete this coating project, four coating runs were required. Each coating run applied an average of 2.5 mils (DFT) per run. This provided a final dry film thickness of 10 mils. Upon completion of the final coating run, the pipeline was subjected to a slow purge of wet air for a period of five days.

Conclusion

The pipeline had experienced 11 leaks prior to insitu coating and, after nine years of service, the line has remained leak free. The company has estimated that the cost to renovate the pipeline by insitu coating was completed for less than 30% of the replacement costs (including mobilisation, offshore marine support and logistical costs). The success of this insitu coating project led the company to rehabilitate an additional 17 pipelines, totaling over 173 miles of 10 - 16 in. pipe.

In addition to being economical, insitu coating has proven to be more effective than chemical inhibition alone in corrosive environments where the dosage and quality of inhibition is unreliable. Insitu epoxy coating has been successfully applied in a number of services including sour oil and gas, water and product pipelines. Insitu coating has also been used for controlling erosion, increasing pipeline efficiencies and maintaining product purity.

Insitu coating may certainly be viewed as a first line of defense when used in a highly corrosive service. However, in order to provide a greater level of assurance against any damage or defects in the coating, continuing to pig and inhibit the pipeline is still recommended.