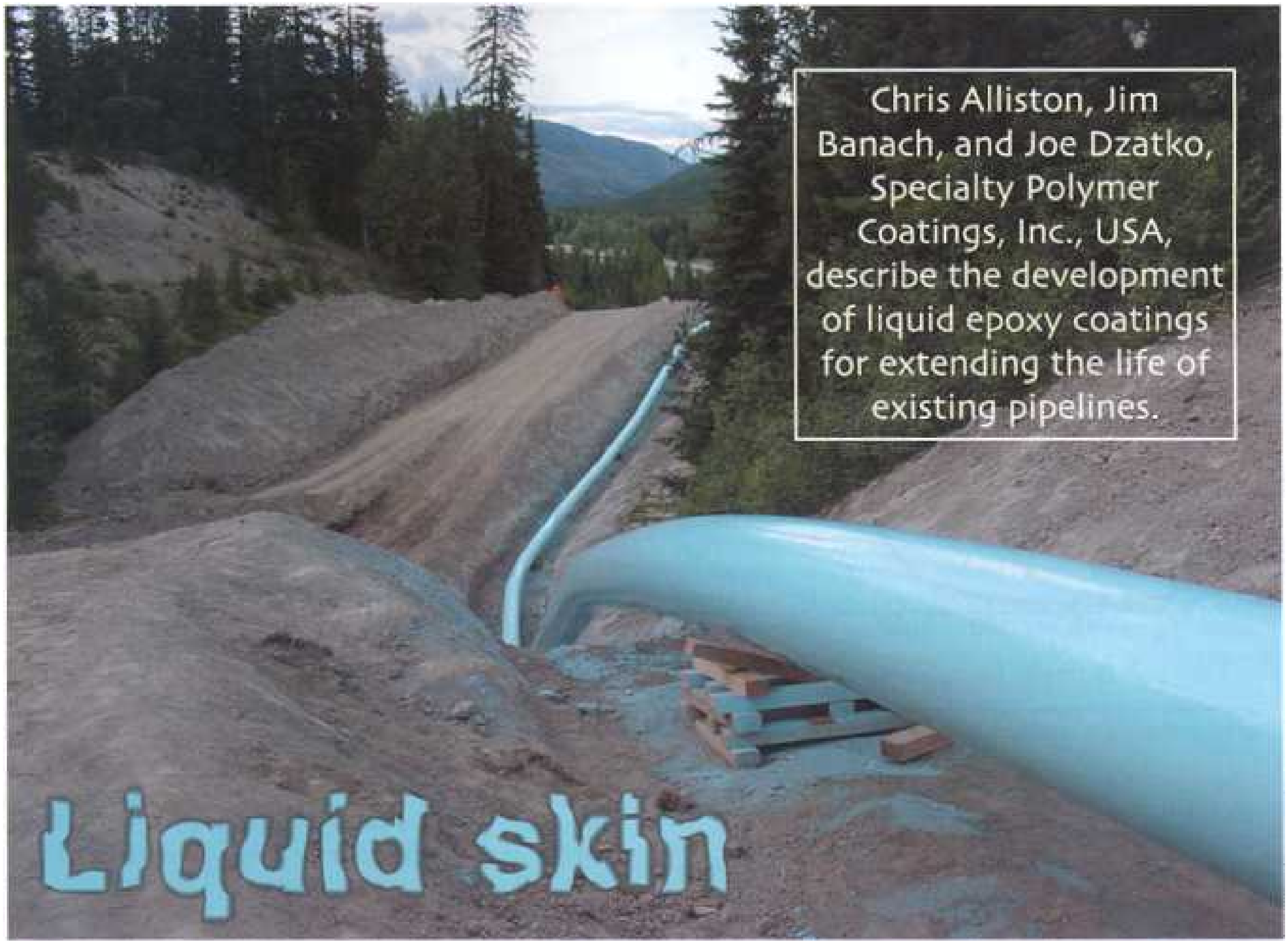

A number of factors affect the longevity of a pipeline. These include quality of construction and protective coating systems, cathodic protection, nature of the environment, operating conditions, and quality and frequency of pipeline maintenance to name but a few.

No one factor influences the long-term integrity of a pipeline more than the effectiveness of its coating system. Pipeline leaks, ruptures and ultimately a pipeline's integrity and useful life can be directly attributed to coating deterioration or failure.

In the year 2000 it was estimated that of the 2.2 million miles of pipeline in the USA, 24% was more than 50 years old. This ageing of pipeline infrastructures and resultant coating deterioration has been the impetus for the development of methods and technologies to rehabilitate older facilities and extend the life of existing pipelines. New coating systems and application techniques have now been developed to enable old and existing pipeline systems to be upgraded in a cost-efficient manner, and to the latest industry standards for protecting facilities from external corrosion and environmental damage.

This article outlines the functions of a pipeline coating, factors leading to coating failure, the consequences of a failed coating system and discusses the advancements made in liquid coating systems and application methods for remediation of pipeline infrastructures.

Corrosion protection of buried pipelines

Corrosion protection is required to maintain the integrity of a buried pipeline system and coatings are the primary protection for a pipeline. As a buried pipeline is subject to corrosive attack if it is in contact with a wet environment, coating the pipeline to isolate it from this corrosive environment is an obvious approach to corrosion control. Since no coating system is defect free, cathodic protection is used to provide supplementary protection.

Most countries have regulations that require pipelines to be coated and in general stipulate that a coating possess the following properties:

- Electrically isolate the external surfaces of the pipeline from its environment.
- Have sufficient adhesion to resist underfilm migration of electrolyte.
- Be sufficiently ductile to resist cracking.
- Resist damage due to soil stress and normal handling.
- Be compatible with cathodic protection.
- Resist deterioration due to the environment and service temperature.

Cathodic protection is fundamental to preserving a pipeline's integrity. Cathodic protection is a method of corrosion control that is achieved by supplying an external direct current that neutralises the natural corrosion current arising on the pipeline at coating defects. Current required to protect a pipeline is dependent on the environment and the number and size of the coating defects. Clearly, for a particular environment, the greater the number and size of coating defects, the greater the amount of current required for protection.

Coating plays an integral part in the functioning of a pipeline's cathodic protection system. Where a coating

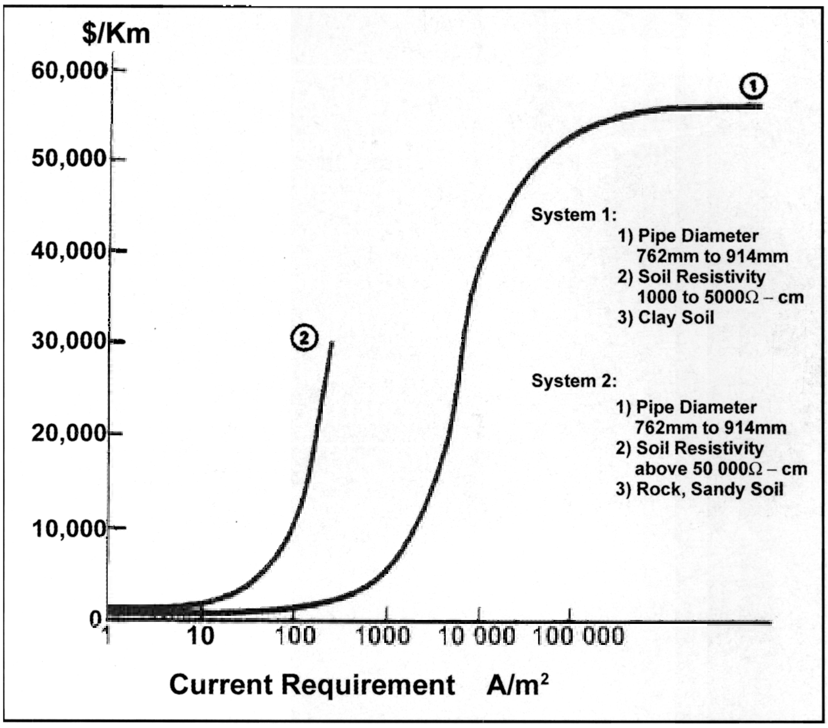

Figure 1. Cathodic protection costs as a function of coating performance.

system has badly deteriorated, cathodic protection requirements and costs can increase exponentially. Until the late 1970s, before the widespread use of epoxy and similar high adhesion coatings, practitioners of cathodic protection typically used a design factor of 3% bare area for a pipeline coating. For tape and enamel systems in use at that time, this design factor was realistic. Today's pipelines, with high adhesion systems, typically require two to three orders of magnitude less current.

Many of the older 'low adhesion' coatings deteriorated over time to the point of total ineffectiveness. Industry experience has shown that this has happened with mastics, asphalt enamels, tapes and to a lesser extent coal tar enamels. Figure 1 illustrates how costs for cathodic protection can accelerate as coating deteriorates. Curves #1 and #2 represent approximately 30% coating deterioration where the curves ascend almost vertically. Additionally, cathodic protection becomes difficult to maintain or even achieve.

In 1995, the National Energy Board of Canada (NEB) held an inquiry into stress corrosion cracking (SCC) on Canadian oil and gas pipelines. In its report filed in 1996, the NEB reported that most of the SCC related failures occurred on pipelines coated with polyethylene tape. The report stated that some polyethylene tapes are prone to disbonding because of tenting created by the tape that occurs between the pipe surface and the longitudinal weld seam. Also, disbondment occurs where the tape is overlapped between successive wraps of tape or where soil stress has caused the coating to move or wrinkle.

Because of the high electrical insulating property of polyethylene and the relatively long path under the disbonded tape, sufficient cathodic protection current cannot reach the pipe to prevent corrosion. This phenomena is called shielding. When shielding does occur it can result in pitting corrosion. Of greater concern, as a result of shielding, is extensive general corrosion or the formation of an environment susceptible to stress corrosion cracking. These two scenarios could lead to catastrophic failure of the pipeline.

In the presence of shielding, over-the-line electrical corrosion protection surveys are suspect in their ability to accurately assess the status of corrosion protection of a pipeline. Other more costly methods such as pigging, hydrostatic testing, or discrete excavations would be needed. Regardless of the method of integrity assessment used, remedial programs will be required if corrosion is found. The remedial options are generally limited to additional cathodic protection, recoating, pipe replacement or a combination of the aforementioned choices. In the case of a disbonded coating causing shielding, additional cathodic protection would not be an effective option, and thus the only alternative is either rehabilitation by recoating or pipe replacement.

Liquid coatings

As can be seen from the above discussions, in many cases recoating of existing facilities is the most viable option for rehabilitating pipelines. In some cases, additional cathodic protection current is unable to provide corrosion protection or the cost becomes prohibitive and will not guarantee corrosion protection to the facility. Coating rehabilitation costs are substantially lower than pipe replacement and coating technology is now available that enables the facility to be upgraded to and exceed existing standards.

Liquid coatings are ideal for pipeline rehabilitation and coating repairs. They are well suited for field application, be it for large recoating projects or for short pipe sections, in-the-ditch or out.

Liquid coating formulations are now available that are 100% solids (no VOCs), do not require a primer and possess high one-coat build capabilities. In addition, these formulations are available in both spray and brush grades to give pipeline operators flexibility in choosing the application technique best suited for the particular project.

Plural component airless spray equipment was developed and enhanced to allow for easy spraying of these formulations in the field, both in and out of the ditch. In addition, automated line travel spray equipment was designed to allow large-scale pipe recoating projects to be undertaken.

For smaller pipeline rehabilitation sites, spray grade formulations utilising airless spray equipment or brush grade formulations using brushes and paint rollers are now available.

100% solids liquid urethane coatings

In the 1980s, 100% solids liquid urethanes began to be used in North America for coating of girth welds, valves, fittings and pipe on new construction projects. Then in the mid-1980s, the first large scale recoating program for pipeline rehabilitation occurred, using these urethanes and specially designed automated line travel coating equipment. Approximately 11.5 km of buried 34 NPS diameter pipe was raised from the ditch, blast cleaned and recoated to a thickness of 0.635 mm.

In general, these polyurethane coatings exhibited the following characteristics:

Advantages:

- Flexibility in formulating.
- High build-single coat application.
- Fast curing at lower ambient temperatures.
- High abrasion and gouge resistance.
- Reasonable cathodic disbondment resistance at temperatures below 50 °C.
- Reasonable tensile adhesion.

Disadvantages:

- Moisture sensitive.
- Poor cathodic disbondment resistance at temperatures above 50 °C.
- Poor hot water adhesion.
- Poor impact resistance at sub zero temperatures.

100% solids epoxy/ urethane coatings

In the late 1980s and 1990s, pipeline operating temperatures began to increase. Epoxy/urethane formulations were introduced which had significantly improved performance properties over urethanes at higher in-service temperatures.

Advantages:

- Improved cathodic disbondment resistance up to 80 °C.
- Improved tensile adhesion.
- Improved hot water adhesion.

Disadvantages:

- Slower curing than urethane.
- Curing stops at temperatures below 5 °C.

In the late 1990s, almost 120 km of large diameter (34 - 42 NPS) pipe were recoated in North America with these formulations, using automated line travel spray equipment.

100% solids epoxy coatings

In the mid-1990s epoxy and novalac-epoxy coatings were
formulated for use in the pipeline industry. These formulations have improved performance characteristics and properties over the earlier coating systems.

Advantages:

- Improved cathodic disbondment resistance at temperatures up to 95 °C.
- Improved tensile and hot water adhesion.
- Improved sag resistance.

Disadvantages:

- Slower curing than urethane.
- Curing stopped at temperatures below 5 °C.
- Higher temperature formulation were more difficult to spray.

Recent developments

In the late 1990s and early 2000s, epoxy coating formulations approached the application advantages of urethane products and possessed performance properties that exceeded those of fusion bond epoxy (FBE). In addition, formulations were further developed to meet particular operating conditions encountered by pipeline operators for pipeline recoating and repairs.

High temperature epoxy

With the industry trend towards higher operating pipeline systems, coatings based on the newest (zero VOC) novalac technology have been developed that cure to a highly crosslinked coating for ultra high temperature service on buried or submerged pipeline facilities. These systems possess superior adhesion and excellent resistance to cathodic disbondment at temperatures up to 150 °C.

Figure 2. Insitu rehabilitation.

Figure 3. Insitu rehabilitation inspection.

Figure 4. Automated rehabilitation equipment.

Low temperature cure epoxy

New epoxy formulations have the ability to cure at temperatures down to 0 °C and still provide the performance properties expected from the use of epoxies. These systems are ideal for coating applications in cool weather (autumn/winter) and provide excellent corrosion protection properties for pipeline facilities operating at temperatures up to 65 °C.

Damp surface epoxy

An epoxy is now available that may be used for coating pipelines where the surface is damp due to high humidity or condensation. This system provides excellent corrosion protection with superior adhesion and resistance to cathodic disbondment at temperatures up to 80 °C.

Conclusion

The development of liquid coating technology has had a significant effect on advancing recoating for pipeline rehabilitation and repair.

- Liquid pipeline coatings have made recoating a most efficient and cost-effective approach for re-establishing the integrity of pipelines and extending the life of aged infrastructure.
- These coating systems exhibit better corrosion protection performance properties as compared to standard 'mainline' coatings and provide higher integrity to the recoated facility.
- New liquid coating enhancements are now available for use in difficult operating conditions and environments.
- In addition, recoating reduces maintenance, integrity monitoring and cathodic protection costs.

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