ABSTRACT

For more than 60 years now, internal plastic coatings have been used for corrosion protection, hydraulic improvement, and deposition mitigation in tubular goods and drill pipe. Internal plastic coatings have historically proven to be a long-term corrosion control solution, even with difficult to treat applications such as top of the line corrosion. For hydraulic efficiency, internal plastic coatings have shown to be able to improve overall flow, allowing for a reduction in pipe size simply by reducing the surface roughness and inherent surface friction. For deposit mitigation, internal plastic coatings have shown the ability to reduce or completely stop the adherence of deposits onto the pipe surface. These benefits have been proven effective in applications from subsea pipelines to simple flowlines tying into an onshore wellhead. Forty years ago, a new and novel connection system allowed for internally plastic coated pipelines to be welded while still having effective protection of the internal weld zone from the environment. This connection system allowed for benefits such as corrosion protection, hydraulic efficiency, and deposit mitigation to be realized in pipeline applications.

Keywords: corrosion coat, flow coat, API, hydraulic improvement, asphaltene, top of the line corrosion

INTRODUCTION

Plastic coatings have been used on pipe internal surfaces in the oil and gas industry for corrosion protection and hydraulic improvement for greater than 60 years. During that time, coating product lines have been diversified to fit certain application needs. When mentioning pipeline coatings, the first thing that typically enters individual’s minds are external FBE (fusion bonded epoxy) coating systems. There are distinct differences in both coating chemistry and coating application between external FBE’s and internal plastic coatings. While all external FBE systems are not the same, they are all based on minor variations of basic epoxy resins. While some internal coatings are also based on epoxy resin chemistry, they can also be based on phenolics, novolacs, nylons, and urethanes. An even greater difference between the two manifests itself during the application process. The application of external FBE’s consists of a drying of the pipe, a wheel-abrader type blast to at best a NACE number 2 finish, an up-
heat, powder application and then a post application quench. The absence of a post cure step can yield improved flexibility, but diminishes the coatings ability to handle more aggressive environments. The application of internal coatings consist of a thermal cleaning (up to a temperature of 750°F (398.9°C) depending on the metallurgy) of the pipe to remove residual organic impurities, an internal blast that yields a NACE number 1 (Sa 3) white metal finish, a phenolic primer, top-coat application (either powder or liquid), and a post cure step (except for nylon coatings). The post cure step ensures optimal resistance to corrosive species at temperature.

There are two basic groups of internal pipeline coatings: flow coats and corrosion coats. These two groups are designed to provide for benefits in very different ways, one through thickness and chemistry, and the other through a smooth consistent surface. These systems have become somewhat diversified in application processes and resin chemistry under their respective groups. Even with this diversification and growth, misunderstanding often exists as to whether a specific coating system provides the benefits to be achieved. When a particular coating system is put into an environment, that it was not designed to withstand, or for a specific benefit it was not designed for and subsequently experiences premature failure, it is considered a coating failure. To look at the issue more realistically, the failure occurred even before the coating was applied to the pipe. A proper decision on an internal coating involves many aspects including: is the coating designed to provide the benefit being sought, will the coating chemistry allow those benefits to be achieved, and are the application procedures sufficient to ensure a quality system.

COATING FOR CORROSION CONTROL

Corrosion resistant coatings rely primarily on being a physical and chemical barrier between the steel substrate and the internal environment. The corrosive species that will typically be encountered in pipeline/transmission line service are CO₂, H₂S, oxygen, chlorides, and acidic compounds. Elevating temperature and/or pressure can exacerbate all of these factors. “Generally, for every increase of 18°F (10°C) in temperature, the rate of a given reaction will double.”² It is widely believed that these species are not corrosive until they are in the presence of water. While there is some industry debate regarding the corrosivity of H₂S without water, for the sake of this document, we will consider the previous statement true. NACE determined that for a coating to be considered for corrosion protection from the corrosive species typically encountered in the oil and gas industry, a minimum of 5 mils of coating thickness is needed.³ It is also necessary that the coating film be dense; not containing entrained air. Once again, the coating is a barrier and needs to possess the physical properties necessary to maintain its integrity while in service.

While coatings used for corrosion control in tubing and casing applications have long fought the stigma of potential wireline and mechanical damage, corrosion control coatings in pipeline applications do not have that issue. Wireline and coiled tubing are not run in pipeline, but pigs are. The polymeric pigs have not proven to be an issue with causing abrasion to the internal coating. It is not recommended that scraper pigs be run as the risk of causing mechanical damage to the coating increases. Intelligent pigs can be and have been run through internally plastic coated lines without issue. Table 1 provides case history information on a sampling of land and subsea lines that have used internal plastic coating technology for corrosion control successfully. All applications listed are still in service having no reported internal corrosion issues. These histories support the contention that a properly selected and properly applied internal coating can be an effective corrosion control solution in many applications.
There are important distinctions that need to be made between the two main types of internal line pipe coatings: flow improvement coatings and corrosion control coatings. While certain corrosion control coatings can provide flow improvements of the same capacity as flow coats, flow improvement coatings do not provide sufficient long term corrosion control. API’s RP 5L2 discusses the “Recommended Practice for Internal Coating of Line Pipe for Non-Corrosion Gas Transmission Service”. This document states “…benefits to be derived from internally coated line pipe are:(1) Improved flow characteristics (2) Corrosion protection during the period preceding construction (3) The enhancement of visual inspection of the internal pipe surface (4) the improvement of pigging efficiency.” These systems are designed for non-corrosive environments in which a thin, smooth consistent film will provide the desired hydraulic benefit through reduced friction at the internal surface of the pipe. The idea behind a flow coat is to provide just enough coating to fill in the valleys generated during the blasting process and yet still have enough material to flow out and produce a smooth finish. API states that for a coating that falls under RP 5L2 guidelines for offering a flow enhancing coating in non-corrosive environments, it must be a minimum of 1.5 mils in thickness. It should also be noted that flow coats falling under these guidelines are not holiday checked, indicating that these systems were not designed for in-service corrosion control.

The physical roughness of a pipe surface will affect the physical properties of flow and the effect of this roughness is dependent upon the relative size of the roughness (the vertical distance from the "peaks" to the "valleys") and the laminar film. A pipe surface is said to be "smooth" if its projections or protuberances are so completely submerged in the laminar film that they have no effect on the turbulent mixing process. However, when the height of the roughness projections approach or exceed the thickness of the laminar film the projections serve to augment the turbulence and if the roughness is excessive it may even prevent the existence of the laminar film. Thus, the thickness of the laminar film is the criterion of effective roughness. Because the thickness of this film varies with certain properties of flow, it is possible for the same pipe surface to behave as a "smooth" or "rough" one depending upon the size of the Reynolds number. Pipe flow experiments have shown that the thickness of the laminar film decreases with increasing Reynolds number. Usually the transition of a "smooth" surface to a "rough" one results from an increase of Reynolds number brought about by an increase of velocity. This indicates that surface roughness is increasingly important in tubing and flowlines that produce at higher velocities. Surface roughness serves to increase the turbulence in a flowing system. It has been concluded that energy losses caused by surface roughness varies with the square of the system velocity. Operators have long utilized internal coating systems to minimize this surface roughness to increase well production, minimize pressure requirements to pump material over a given distance and to maximize the volume of material that can be pumped.

Hydraulic Improvement Case History 1

A Gulf of Mexico operator was looking at either chemical inhibition or internal plastic coatings to provide corrosion control and deposit control for a subsea pipeline. Corrosion modeling indicated that they would not be able to meet the minimum design life of ten years without some level of corrosion protection. In addition to corrosion control, the application of the internal plastic coating would also provide an additional benefit; it would allow the operator to use 6” line pipe rather than the planned 8” pipeline that they would have to use if they chose only chemical inhibition. Still a third benefit from running the internal plastic coating was the minimization of pig runs due to the organic and inorganic deposit mitigating benefit of the coating. If you looked at the cost for the actual materials: the line pipe itself, the cost for the external coating, the cost for the internal coating/chemical inhibition (1st
the overall price differential was negligible. When you factored in the additional chemical inhibition for the remainder of the design life of the line, the savings from going with the internally coated system increased to over $325,000 US. When you also add in the savings from minimizing pig runs and construction and material cost for satellite corrosion inhibitor platforms, the differential climbs into the millions.

Hydraulic Improvement Case History 2

An international customer utilized internal plastic coatings to provide corrosion protection and hydraulic improvement to a sub-sea flowline. The project consisted of a 6" line that was 4500 m (14763.8 ft) long to be used for transporting injection water. Graph 1 shows the flow differences at several pressures between the internally bare line versus the internally coated line. At a pressure of 1250 psi, the internally bare line will flow 25,907 bbl/d and the internally coated line will flow 28,586 bbl/d for a 9.3% increase in flow.

COATING TO PREVENT DEPOSIT FORMATION

The ability of certain internal plastic coatings to mitigate paraffin and scale deposits has been discussed previously in “Paraffin Deposition and Prevention in Oil Wells” by R. M. Jorda and in OTC paper number 16026: “The Benefits of Using Internal Plastic Coatings on Chrome Tubulars”. Paraffin precipitation is purely thermal in nature, but adherence to a surface is both thermal and mechanical. A surface cooler than the WAT (wax appearance temperature) and cooler than the surrounding fluid will provide a place for the paraffin to precipitate and begin to deposit. Having a rough surface profile for mechanical binding allows this precipitated paraffin to remain adhered to the surface. Internal plastic coatings help mitigate paraffin deposition by offering a small level of insulation to the steel surface as well as offering a minimally rough surface making any paraffin that might precipitate pass through the system versus becoming mechanically bound to the surface.

There are several factors that will cause the formation of scale deposits: pressure drops, temperature changes, mixing of incompatible waters, pH changes, agitation and contact time. Pressure drops, temperature changes and contact time all alter the solubility of the scale in the produced water. Lowering that solubility will cause the scale to crystallize and form a deposit. Mixing of incompatible water can also alter the solubility, and bring cations and anions together that were initially not present in sufficient amount in either water alone to cause a deposition problem. As the pH rises, becomes more alkaline, the solubility of calcium carbonate and calcium and iron phosphate decreases. The hydroxide ion, associated with higher pH, will help the scale crystallization reaction. Agitation can bring into contact cations with anions as well as scale molecules to increase the probability of scaling. The most prominent ways of dealing with a scaling problem are mechanical/operational changes, alteration of water chemistry, periodic removal of scale, or chemical inhibition. An internal plastic coating mitigates scale formation and deposition in several ways. First, by preventing corrosion in the system, iron based scales will be prevented (unless there is free iron in the system – which is rare). Secondly, the internal coating has a smooth surface which mitigates the precipitated scales ability to adhere to the surface.

More than 20 years of history has proven the effectiveness of certain coating systems in the prevention of paraffin and scale deposition, success in asphaltene mitigation has been relatively recent. The prevention of asphaltene precipitation has proven difficult due to wide variations in both the asphaltene molecule and the associated resin that keeps it in solution. Current practices dictate that there are four ways to deal with asphaltene deposition: solvent removal, mechanical removal, and dispersants/inhibitors. Certain types of polymeric coating materials have shown, through laboratory
evaluation, to possess the necessary surface characteristics for the mitigation of asphaltene deposition regardless of its precipitation. The application of a polymer based coating system, with a sufficient chemically inert surface, has also shown the ability to prevent the not just the deposition but also the tenacious adherence of asphaltene deposits in field applications.

The below data is the beginning of a basic understanding of why certain materials indicate effectiveness. The lower or more negative the Hamaker value (surface energy) in conjunction with a lower or more negative sticking tendency, the more effective the system will be in mitigating asphaltene deposition.

“A negative Hamaker value (\(A_{\text{SLR}}\)) occurs when dielectric properties of the medium (asphaltene lean phase) have a value intermediate between the dielectric properties of the substrate and the precipitated asphaltene rich phase. In this case, Hamaker constant will represent a sticking probability of asphaltene aggregates on the substrate. Figure 1 shows zero tendency for asphaltene to stick on PTFE (Teflon) and PVDF and a positive tendency for the rest of materials proportional to their surface energy level.”\(^5\) Unfortunately, what makes fluoropolymer materials desirable, low sticking tendency, is what also makes them difficult to utilize as a coating. Under many oilfield conditions, these fluoropolymer coatings will lose adhesion, causing large scale coating disbondment. Utilizing an internal coating that is designed to remain adhered even in severe downhole and flowline environments, yet still provides low sticking tendencies allows for the best of both worlds.

**COATED LINE PIPE WELDABLE CONNECTION SYSTEM**

The use of internal plastic coatings to control corrosion, improve hydraulics and mitigate deposit formation in flowlines and pipelines has been practiced for more than 35 years. When internally coated line pipe is welded together; there will be a small area at the end of the pipe that will experience coating degradation. What overcame this issue was the development of a proprietary sleeve system that isolates this area of damage behind the internally coated sleeve. The sleeve is manufactured from cold drawn mechanical steel and is also internally coated for corrosion mitigation. The sleeve itself is held into place either by tabs that become consumed in the weld or by a chill ring that is tied into the root pass of the weld. Photo 1 and Photo 2 are offered as examples of these sleeve systems. These sleeve systems still allow for intelligent pigging to be performed through the pipe but the operator needs to ensure that the gauge pig run prior to the intelligent pig is sized to pass through the internal of the sleeve. A ¼ mile flow loop test was performed in 1993 where internally coated line pipe was connected using the Thru-Kote UB connection system. Eight intelligent pig runs were made at various speeds with the rotators turned off to ensure that the Thru-Kote sleeve was impacted at the same place each time. Post test analysis indicated that there was no damage to either the internal coating or to the Thru-Kote UB sleeve. There are some coatings on the market of sufficient thickness as to prevent accurate measurement, but the internal coatings being discussed in this document do not approach that thickness. Sleeve systems such as these have been used in internally coated pipelines for more than 35 years with a track record of success in protecting the weld zone from corrosion. The total package will provide 360° coverage down the entire length of the line.

**CONCLUSION**

Internal plastic coatings offer benefits that can help protect a pipeline and yield a more flow efficient system. In order to attain these benefits, it is important that the specified coating meet the requirements to perform that benefit. It is very important to understand what is trying to be achieved through the use of the coating, will that coating survive the environment it will be exposed to, and will
the application of that coating meet the requirements to ensure success in a given environment. No longer can it be left to chance what is being put into a pipeline system for corrosion protection. Education can allow for a proper system to be installed and the desired benefits to be achieved.

### TABLE 1

<table>
<thead>
<tr>
<th>Location</th>
<th>Pipe Diameter, in</th>
<th>Length of Line, ft</th>
<th>Year Installed</th>
<th>Coating Type</th>
<th>Line Temperature, °F/°C</th>
<th>Line Pressure, psi</th>
<th>CO₂ Concentration</th>
<th>H₂S Concentration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Canada</td>
<td>3</td>
<td>8,000</td>
<td>1972</td>
<td>Epoxy</td>
<td>250/121</td>
<td>100</td>
<td>Trace</td>
<td>51 ppm</td>
</tr>
<tr>
<td>Kuwait</td>
<td>3, 4, 6, 10</td>
<td>400,000</td>
<td>1996</td>
<td>Epoxy Novolac</td>
<td>230/110</td>
<td>5000</td>
<td>Trace</td>
<td>Trace</td>
</tr>
<tr>
<td>Indonesia</td>
<td>4 and 8</td>
<td>69,000</td>
<td>2000</td>
<td>Epoxy Novolac</td>
<td>248/120</td>
<td>2100</td>
<td>11%</td>
<td>Trace</td>
</tr>
<tr>
<td>Libya</td>
<td>3 and 4</td>
<td>309,200</td>
<td>1984</td>
<td>Epoxy Phenolic</td>
<td>190/80</td>
<td>1000</td>
<td>4%</td>
<td>Trace</td>
</tr>
<tr>
<td>US Onshore</td>
<td>3 and 16</td>
<td>42,000</td>
<td>1991</td>
<td>Epoxy Phenolic</td>
<td>200/93</td>
<td>1200</td>
<td>1%</td>
<td>50 ppm</td>
</tr>
<tr>
<td>US Offshore</td>
<td>6</td>
<td>10,000</td>
<td>2000</td>
<td>Phenolic</td>
<td>200/93</td>
<td>2000</td>
<td>10%</td>
<td>2000 ppm</td>
</tr>
<tr>
<td>US Offshore</td>
<td>6</td>
<td>30,000</td>
<td>1999</td>
<td>Epoxy Phenolic</td>
<td>225/107</td>
<td>1500</td>
<td>2.8%</td>
<td>N/A</td>
</tr>
<tr>
<td>US Offshore</td>
<td>8</td>
<td>30,000</td>
<td>1999</td>
<td>Epoxy</td>
<td>200/93</td>
<td>1700</td>
<td>3.6%</td>
<td>N/A</td>
</tr>
</tbody>
</table>

### GRAPH 1: Hydraulic improvement case history number 2 results
FIGURE 1 - Surface energy and Hamaker constant for polymers and metals at 20°C

FIGURE 2 – Sticking tendency of asphaltene on different materials
REFERENCES

3. NACE RP0191-02, Standard Recommended Practice, "The Application of Internal Plastic Coatings to Oilfield Tubular Goods and Accessories."