Successful Water Injection and Disposal Applications of Thermoplastic Lined Downhole Tubing: A Compilation of Case Histories Dating Back to 1998

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ABSTRACT

Thermoplastic liners are commonly used to protect a wide range of oilfield tubulars offering the advantages of increased corrosion resistance, wear mitigation, and ease of tubular installation while diminishing pressure drop issues and maximizing fluid throughput capacity especially in high rate wells operating with high velocity fluids. Furthermore, they may offer a competitive advantage over corrosion resistant alloys (CRA's), plastic coatings and thermoset liner products in extending tubular life.

The most commonly used thermoplastic liners in water injection service are largely extruded from polyolefins for installation in environments up to 99°C; yet, for more demanding environments, engineering thermoplastics such as PPS are available to handle temperatures as high as 175°C. All of these polymers are significantly more flexible and impact resistant compared to traditional thermoset materials historically used to protect injection tubing meaning that they can be practically applied in harsh field conditions and maintain a protective barrier against the tubing ID even after pulling/rerunning tubing combined with multiple wireline and coiled tubing surveys. The same liners can be used to protect costly downhole components and jewelry such as packers and tubing anchors. Examples of lined tubulars with both API and premium tubular connections will be covered.

This paper will present case studies detailing the successful use of thermoplastic lined tubulars including liner products composed of HDPE, a proprietary polyolefin blend, and PPS. All of the lined tubulars in these wells are still in service today and some were installed back in 1998. A review of critical limitations of the liners such as temperature and diameter reduction effects will also be discussed in an effort to avoid the misapplication of thermoplastic liners. Economic benefits, improved service life, and better flow characteristics due to the high quality surface finish of the liners will be detailed in thirteen different fields and water injection environments. Furthermore, to exhibit the overall economic impact of thermoplastic lined tubulars, a review of field installation and handling procedures will be presented as well.

The fundamental technical benefits of various thermoplastic lined tubulars will be covered with an emphasis on the proven extension of tubing service life using thermoplastic liners.

1. INTRODUCTION

1.1. Types of Polymer Products Used to Protect Downhole Injection Tubulars

1.1.2. Historical Overview Going back to the middle of the twentieth century, only thermoset plastic products were significantly used to protect the inside diameter (ID) of injection well tubing from corrosion.

Initially in the 1940's, thermoset internal coatings with a phenolic primer were applied to the tubing ID to try and isolate carbon steel API oil country tubular goods (OCTG) from attack in the aqueous injection environment. It was found that when they remained intact, these coatings were an effective barrier that mitigated corrosion due to bacteria, chlorides, galvanic attack, and dissolved gases such as oxygen, carbon dioxide, and hydrogen sulfide. These coatings were thin with minimal resistance to impact and not very flexible commonly resulting in a breached barrier and unprotected areas of the tubing from handling and in-service induced mechanical damage culminating in tubing leaks. Approximately 20 years later, in the 1960's, thermoset glass reinforced epoxy (GRE) liners were introduced with improved damage resistance compared to thermoset coatings. To a much lesser extent, operators have also used polyvinyl chloride (PVC) liners in very low temperature applications with short term success. The most recent developments include a family of thermoplastic liners (TPL) that vary in chemical resistance but the primary distinguishing feature is the allowable service temperature of each polymer material. With a large focus by the polymer research community on thermoplastic chemistry, it can be argued that the next generation of tougher tubular protection products will probably be thermoplastics.

2. THERMOPLASTIC LINER SPECIFICATIONS

2.1. Technical Data on Thermoplastic Lined OCTG

2.1.1. Types and Temperature Limits of Thermoplastic Liners Western Falcon Polycore™ high density polyethylene (HDPE) thermoplastic liners have been successfully used for over twenty years to protect water injection tubulars. Although they have performed with a near flawless track record in both new and used tubing in over 14,000 wells, HDPE liners are limited to a maximum temperature of only 80°C in water handling service. Because of that limitation, a new proprietary blend of polyolefins (does not contain any HDPE), known as Western Falcon Enertube™ was tested and developed approximately ten years ago with the capability of operating in temperatures as high as 100°C. The unique blended polyolefin liner has now been used successfully for over nine years in downhole injection tubing. As deeper corrosive injection wells were considered, Western Falcon Ultratube™ liner made from polyphenylene sulfide (PPS) was developed over five years ago with the capability of operating in wells with maximum operating temperatures as high as 175°C. Finally, the most recently developed thermoplastic liner product is Western Falcon Extremetube™ manufactured from polyetheretherketone (PEEK) polymer designed to handle corrosive environments downhole as hot as 260°C. While it is worth mentioning for high temperature severe service environments, the PEEK liner product is very new and not covered in the context of this paper. The higher temperature engineering thermoplastic liners are significantly higher in cost compared to the lower temperature polyolefin liners. Temperature is just one important variable that must be considered when evaluating any polymer for use downhole and TPLs are no exception. It is important to accurately assess the entire environment that the liner will be exposed to both operationally and during well servicing and treating operations. A complete holistic evaluation of the well environment is warranted before deploying any polymers into the well as some of the fluids in the wellbore may actually reduce the allowable operating temperature and pressure for a liner.

2.1.2. Properties, Dimensions, and Installation of Thermoplastic Lining Systems Thermoplastics are typically much more ductile and resilient compared to their thermoset counterparts used to protect downhole tubulars. The increased ductility translates into a material that is very resistant to damage from wear (abrasion from sand, wirelines, both rotating and reciprocating sucker rods and coiled tubing), impact (sucker rods, connection stabbing and makeup, and wireline tools) and flexing or yielding (common on the thin pin ends of connection systems of OCTG) of the steel tubing substrate they protect.

Primarily because of the unique combination of wear resistance and flexibility, the primary use for TPL tubing today is to stop rod on tubing wear downhole especially in corrosive environments where the synergistic combination of corrosion and wear result in very short well run times. Use of today's TPL OCTG has drastically extended the life of tubulars by minimizing the effect of in-service induced damage to the polymer protection barrier compared to other materials. Additionally, thermoplastic materials are elastic and tend to stretch but then return to their original configuration and dimensions. For this reason, thermoplastic liners are manufactured larger in outside diameter (OD) than the ID of the steel tubulars they are inserted into which allows for the formation of a "tight fit" mechanical bond compressing the OD of the liner tightly against the ID of the steel OCTG. Unlike other tubular protection products, the lack of any adhesive or chemical bond to the steel allows the liner to move independently from the steel and maintain its ductility and elongation properties (as opposed to becoming limited by the ductility of the steel if the two were bonded where the polymer barrier-OCTG bond, the liner material, or both are compromised). Western Falcon has developed a proprietary method to form a large "flange" on each end of the tube composed from the original liner material (excess that is left extending beyond the ends of the tubular when it is lined). This proprietary procedure creates a continuous seamless thermoplastic tube without any leak paths at the liner connections (i.e. the liner and end flanges are continuous and from the same original extruded thermoplastic tube). An example of this "flange" or anchor is shown in Figure 1. The liners range in thickness from approximately 3 to 6 mm depending on the diameter of pipe that is lined. A wide range of OCTG diameters have been successfully lined ranging from tubing as small as 1.900-inch OD and casing as large as 7-inch OD. In order to provide a protective polymer layer thick enough to withstand most common OCTG handling practices, the liners typically reduce the tubular bore by between 6 mm and 9 mm on tubulars in this size range (see Table 1). A new lining machine (currently scheduled to be stationed in the Gulf States region) has been engineered by Western Falcon to line tubulars as large as 16-inch OD with the same thermoplastic liner products.

Dimensions and Drift Diam.

Size	Weight	Tbg Wall	Bare ID	Poly Lined Drift	Coupling OD EUE 8rd Regular	Coupling OD EUE 8rd S. Clearance	Coupling OD NUE 10rd Regular	Coupling OD NUE 10rd S. Clearance
1.900" (1 1/2)	2.90#	.145"	1.610	1.250	2.500			
2 1/16"	3.25#	.156"	1.751	1.350			2.500	
2 1/16"	4.25#	.225"	1.613	1.200			2.500	
2 3/8"	4.70#	.190"	1.995	1.600	3.063	2.910	2.875	2.700
2 7/8"	6.50#	.217"	2.441	2.000	3.668	3.460	3.500	3.220
3 1/2"	9.30#	.254"	2.992	2.500	4.500	4.180	4.250	3.865
4 1/2"	10.50# Csg	.224"	4.052	3.500	5.000			
4 1/2"	11.60# Csg	.250"	4.000	3.500	5.000			
4 1/2"	12.60# Csg	.271"	3.958	3.400	5.000			
5 1/2"	14.00# Csg	.224"	5.012	4.500	6.050			
5 1/2"	15.50# Csg	.275"	4.950	4.400	6.050			
5 1/2"	17.00# Csg	.304"	4.892	4.300	6.050			
5 1/2"	20.00# Csg	.361"	4.778	4.200	6.050			

Table 1: Dimensions for Bare and TPL Common Tubing and Casing Sizes (all values in inches)

2.1.3. Surface Finish of TPL Products and Effects on Pressure Drop As previously noted, the presence of a TPL robust enough to withstand common oilfield handling creates an undesirable ID constriction in downhole tubulars. Because of this diameter reduction, it is common to imply that the mass transfer capacity of the tubular is reduced and/or the pressure drop to move the same amount of fluids will increase. Historical fluid dynamics research by Reynolds in the 1890's proved that this is not always the case. Reynolds concluded in his research that the surface roughness of a pipe is one of the five primary variables that determine the capacity and pressure drop of fluid flow in that pipe. He concluded that this effect is greater at higher velocities and in turbulent flow regimes. Measurements using a surface profilometer prove that TPL tubulars are approximately 30 times smoother than new (prior to installation in service) bare carbon steel OCTG: 1.5 X 10^{-3} mm for the TPL ID surface versus 4.6 X 10^{-2} mm R_{ZDIN} values for the ID of new steel OCTG. This difference can be significant. When modeling the flow regimes for water injection, the surface roughness alone (even when also taking into account the smaller ID caused by the TPL) can produce a decrease in the friction component of the pressure drop of over 35 percent (this example assumes injection rates of 50,000 BPD in 15.5#/ft, 5 ½-inch casing). This is just one example showing high rates in a turbulent flow regime. By placing the correct values for surface roughness and nominal ID in modern nodal analysis programs that incorporate accepted fluid flow models in pipe, each individual case can be analyzed to verify if a benefit is present and predict the expected magnitude of that benefit. It is important to note that bare steel surfaces will typically corrode or form a passive film on the ID that will cause the surface to become rougher once they are run downhole. However, a properly selected TPL is inert to the operating environment and should maintain the smooth surface while in operation.

2.1.4. Compatibility of TPL with OCTG Connections Many different types of tubular connection systems (thread system designs) are used with TPL products. Both API (see Figure 2) and premium specialty threaded and coupled products can be successfully lined using TPL systems. In the past, premium threads have incorporated a corrosion barrier ring to act as a transition between the metal sealing surfaces and the polymer protection system used on the ID of the tubing. One advantage of TPL tubing is that the liner already has a prefabricated substitute for the corrosion barrier ring on the end of the tubing with the "flange" anchor on both ends of the liner extending past the end of the threaded tubular. In many cases, it is possible to modify existing "approved" tubular connection systems to accommodate the TPL system. Western Falcon is currently working with connection manufacturers to finalize "TPL" versions of their connections for various operators. One particular example of this is shown in Figure 1. It is important to note that important and desirable connection design characteristics such as a flush ID, torque shoulders, and sliding (even pin nose) tapered radial seals (both primary and secondary) can be compatible with TPL lined threaded and coupled OCTG.

2.1.5. Field Handling and Installation Practices TPL OCTG do not require special equipment to install or remove the string from the well. If API threaded and coupled connections are used, API minimum torque is recommended to extend the life of the threads and ultimately the tubing string without causing drift obstructions. In all cases, the maximum operating temperature for the liner in use must not be exceeded (not even for short periods like hot oiling or hot watering a well). Pin end thread protectors are required when standing strings back (to be installed immediately after breaking connections on rig floor) on the rig floor and should remain on the tubing until immediately prior to stabbing the connection above the slips on the well servicing unit when running TPL OCTG. Tools with very sharp metal surfaces should be operated inside of TPL OCTG. If there is any concern that the liner has been compromised from severe mechanical damage (i.e. fishing of parted rods) or the drift ID is critically close to tools that will be run in the well, the lined tubing should be drifted when rerunning back in the well.

3. THERMOPLASTIC LINER CASE HISTORIES IN WATER INJECTION SERVICE

3.1. Past Field Performance in Various Operating Conditions

3.1.1. Spraberry Field, Permian Basin, USA One independent operator has been using HDPE lined tubing to complete over 60 water injection wells ranging in depth from 1,150 m to 1,300 m with temperatures up to 60°C and pressures of approximately 6,900 kPa. These wells are injecting approximately 2,000 BPD of produced water in 1.600-inch ID drift and 2.000-inch ID drift lined tubulars. The first wells were installed in 1998 and they are all still operating today without any reported tubing leaks or failures.

3.1.2. Velma Field, Ardmore Basin, USA Several independent operators have been using internally HDPE lined OCTG in this field since January, 2001. One operator has installed 30 wells with 1.600-inch drift ID lined tubing and 20 wells with 2.000-inch drift ID lined tubing at depths over 1,800 meters and temperatures up to 70°C. These wells inject produced water at rates below 1,000 BPD. No tubing leaks or liner problems have been reported.

3.1.3. Permian, Arbuckle, and Fairbanks Formations; Mid-Continent, USA Another independent operator has operated over 40 internally HDPE lined produced salt water injection wells since 2002 without any reported problems or leaks in the lined tubing. These wells operate at maximum temperatures of 60°C injecting between 700 BPD and 1,000 BPD of water. The wells are completed using TPL 2 3/8-inch and TPL 2 7/8-inch tubing at a maximum depth of 1,400 meters.

3.1.4. Brown Dolomite Formation, Oklahoma, USA This salt water disposal company operates a few wells with HDPE lined OCTG injection strings. The injection strings are approximately 1,600 meters deep and utilize 5 ½-inch, 15.5 #/ft, API 5CT J-55 casing with a 4.550-inch nominal lined ID. The injection rates vary between 10,000 BPD and 17,000 BPD of produced salt water. The surface pressure on these wells is approximately 6,900 kPa and the maximum bottom hole temperature is estimated to be below 70°C. These wells have been operating since December, 2006 without any tubing related issues.

3.1.5. Clearfork and Capitan Formations, Permian Basin, USA A major operator has been using HDPE, Western Falcon Enertube™, and PPS lined tubulars to inject produced water in over 100 wells since 2001 without any reported issues. Most of the tubulars are 2 7/8-inch with a lined drift ID of 2.000-inch. The typical well is approximately 1,000 meters deep and operates below 50°C and at pressures below 21,000 kPa injecting water with a chloride concentration of approximately 60,000 ppm.

3.1.6. South Texas, USA Independent operator using Western Falcon Enertube™ lined 2 7/8-inch OCTG at a depth of 3,422 meters disposing of salt water at a rate of over 1,700 BPD at a pressure exceeding 32,400.00 kPa, at a temperature exceeding 85°C. This well has been operating daily without any issues for over one year.

3.1.7. Permian Basin, USA A large independent water flood operator has successfully installed over 41,000 joints of HPDE lined 2 3/8-inch and 2 7/8-inch OCTG in over 400 sour salt water injection wells since 2000. The average well depth is 1,000 meters, the typical injection rate is approximately 750 BPD at approximately 7,500 kPa, and the average temperature is below 40°C. The formation water has a chloride content ranging from 40,000 ppm to 125,000 ppm. In addition to lining the tubing, this operator also uses the same liner to protect his packers. Additional injection wells are still being completed weekly in this field with HDPE lined OCTG.

3.1.8. Rocky Mountains, USA An oil and gas producer in the US Rocky Mountain region has been using Western Falcon Enertube™ lined OCTG in two water injection wells since January, 2006 and July, 2007. Both wells are completed using 2 7/8-inch tubing with a lined drift of 2.000-inches. These wells are injecting 9.5 PPG water containing 170,000 ppm chlorides with a pH ranging from 2 to 11. The water is very corrosive and has corroded holes in 316SS nipples in approximately 30 days. The pressure in these wells is over 24,000.00 kPa and the temperature is approximately 99°C. All lined tubulars have performed without any incidents since installation. One well suffered a hole in an epoxy coated packer mandrel in January, 2010 but the lined tubing was reinstalled and continues to operate in that well today.

3.1.9. Ellenburger and Devonian Formations; USA This operator utilizes OCTG lined with HDPE, PPS, and Western Falcon Enertube™ in ten fields with the first installations occurring in 1999. While the lined tubulars are replacing failing ID thermoset coated tubing in the injectors, they are also used to solve rod on tubing wear issues in producing wells in the same fields. In one well, the operator has used HDPE lined 5 ½-inch casing as the injection string at depths as great as 2,740 meters injecting between 12,000 BPD and 15,000 BPD. The well is on a 30-inch vacuum. The produced water contains high concentrations of both CO_2 and H_2S and between 65,000 ppm and 180,000 ppm chlorides. There are no reported failures in the lined tubing in these ten fields since the initial installation over eleven years ago.

3.1.10. Cherokee Formation, USA A large international oil and gas producer has been replacing internally thermoset coated tubing that was underperforming with HDPE lined tubing in 18 produced water injection wells since 2007. The injection rates are approximately 1,100 BPD at temperatures between 50°C and 65°C and depths between 1,200 meters and 2,000 meters. All of these wells are successfully operating today without a single incident since initial installation.

3.1.11. Powder River Basin, Rocky Mountain Region, USA One operator has been using HDPE lined OCTG to protect their injection wells for over five years in the Powder River Basin. The first well was completed with over 2,150 meters of 2 3/8-inch tubing with a lined drift ID of 1.600-inch and has a maximum bottom hole temperature of 72°C. It is injecting salt water with dissolved CO2 at a pressure of approximately 10,700 kPa. This operator has never had any operational problems with their TPL OCTG.

3.1.12. Woodbine Formation, East Texas, USA Produced water disposal company has completed approximately 10 wells with 1,100 meters of HDPE lined 5 ½-inch casing with a lined drift ID of 4.500-inch in each well. The first wells were installed in January of 2004. The operating pressure is over 10,000 kPa and the bottom hole temperature is approximately 50°C with injection rates averaging 17,000 BPD per well. The water has a specific gravity of 1.046 and contains 38,000 ppm chlorides. As a produced water disposal company, the operating costs for their water disposal wells are very important. With over 6 ½ years of experience using HDPE lined casing in their wells, they have closely studied the effect of the smooth ID thermoplastic liner on their pressure drop and pump energy costs. They have reported substantial energy savings compared to unlined casing wells even high enough to pay for both the TPL and new API 5CT J-55 steel injection casing string in less than 18 months.

3.1.13. Southern Alberta, Canada Three produced water injection wells installed between September, 2005 and June, 2006 using 1,500 to 1,600 meters of 2 7/8-inch HDPE TPL OCTG operating between 10,000 kPa and 12,000 kPa at temperatures below 40°C.

4. CONCLUSIONS

With over twelve years of successful documented operation under very extreme water injection conditions, TPL have proven to outperform other polymers in protecting OCTG from corrosion and abrasion. The ductility, thickness, and impact resistance of thermoplastics are able to handle most of the daily abuse seen on well servicing and drilling units. There have been no reported incidents of damaged liner (including by wirelines, coiled tubing, tools, etc…) in any of the case histories presented in this study. It is important to note that while TPL have dramatically improved the damage resistance of OCTG polymer protection products, they are not indestructible and can be mechanically damaged when handled abusively or improperly.

With a wide range of proven benefits like lower capital expenditure requirements, reduced tubular maintenance, corrosion control, improving flow characteristics inside the pipe, reducing the pressure drop, and ease of installation, removal and reinstallation, TPL tubulars are still growing in their use both inside and outside of North America. The value proposition that TPL tubulars bring include using existing equipment and installation methods with very few minor modifications to standard procedures resulting in the ability to install injection tubulars with extreme reliability and service life expectations in severely corrosive wells measured in decades.

5. FIGURES

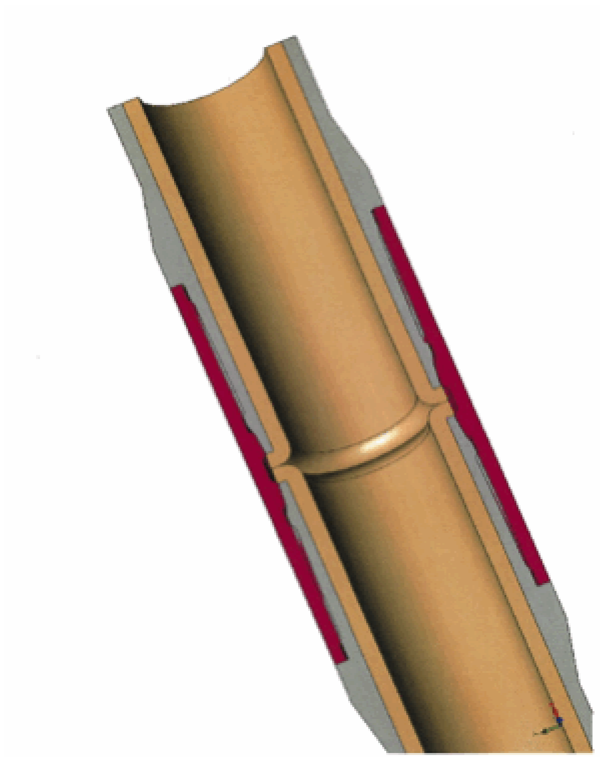

Figure 1: Premium Connection with Thermoplastic Liner

Figure 2: API Tubing Connection Lined with Engineering Thermoplastic