Successful Installation of CO2 Injection Equipment: A Case Study*

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ABSTRACT

Corrosion of injection equipment is a common problem in CO2 miscible injection operations. The two basic mechanisms by which this corrosion occurs are from internal corrosion caused by holidays in the injection tubing coating as well as from external corrosion caused by CO2 invading the tubing-casing annulus through minute seepages in the downhole injection equipment. Unfortunately, these problems are both common and costly.

In one West Texas CO2 injection project, Unocal Corporation, using state-of-the-art connection and testing procedures has developed a method of installing downhole CO2 injection equipment which virtually eliminates this tubing-casing communication. In addition, the internal plastic coating of the tubulars remains intact and holiday-free during field handling procedures. The system involves the use of a helium connection test combined with meticulous attention to detail in the field handling and connection of the tubulars.

The following is a discussion of the development and implementation of these procedures.

INTRODUCTION

CO2 injection was initiated into four wells in the Dollarhide Unit, located in Andrews County, Texas, in June, 1985. Injection into the Devonian formation (average depth--7800 ft. (2380 m)) commenced through casing perforations below a packer at a surface injection pressure of 1350 psig (9300 kPa). The first fourteen installations all utilized 2-3/8" (60.32 mm) internally plastic-coated tubing and eight-round threaded couplings. Various types of eight-round couplings and thread lubricants including modified seal ring couplings, premium nose seal couplings, API Modified thread lubricant, high Teflon thread lubricant, and Teflon tape were installed. All systems developed tubing-casing communication of varying degrees in a relatively short time after injection commenced. Attempts to accommodate the situation by using high concentrations of corrosion inhibitor in the packer fluids were abandoned when the first injection tubing string

* Permission granted to reprint.

SPE Preprint 17294 presented at the SPE Permian Basin Oil and Gas Recovery Conference, Midland, Texas, March 10-11, 1988.

failed due to external corrosion after only eighteen months of service. Close examination of the failed tubing showed nothing to indicate that the corrosion seen on the tubing was not affecting the casing as well.

In light of these severe conditions, each component of the injection well system that could possibly contribute to the problem was analyzed with the aim of maximizing performance from each component. Once this was accomplished the procedures could be economized to produce the optimum injection well equipment installation program.

The final program of an opposing slip packer, modified eight-round couplings, high graphite thread lubricant, and closely monitored field installation procedures has been performed on six CO_2 injectors to date. Five of these six wells currently inject with no communication between tubing and casing. The remaining attempt failed for reasons which are still undetermined.

DISCUSSION:

Injection Packer Selection

Injection packer selection was predicated on the ability of the packer to form an adequate seal between the packer and tubing, between the packer mandrel and the packer body, as well as between the on-off tool and packer body. In order to best effect a seal between the packer body and the casing wall, the softest rubber which would stand up to CO_2 injection service was chosen. It was believed that a softer rubber would more readily conform to the relatively rough casing wall. A polyepichlorhydrin rubber was selected since it is resistant to CO_2 degradation at hardnesses as low as 70 - 80 Durometer. One attempt was made using a nitrile elastomer. The injection system is performing satisfactorily at present, but difficulties were encountered in setting the packer. In light of the satisfactory performance of the polyepichlorhydrin, use of nitrile elastomers as the main packing elements was discontinued.

In order to ensure the most effective pack-off, stress calculations were performed to determine the optimum setting force. These forces were determined to be 25000 pounds (110000 N) for 5-1/2 inch casing and 35000 pounds (160000 N) for 7-inch casing.

In order to maintain this sealing pressure during injection operations, a packer was selected which has opposing slip segments. Once set, these segments maintain sealing pressure independently of tubing-to-packer forces encountered during injection.

Tubular Connections

When evaluating tubular connection design, careful consideration was given to the anticipated service conditions of both the tubing and the connection. Since the injection tubing was to be utilized in CO_2 WAG injection, corrosion control dictated that the tubing be plastic coated. This played a major role in the selection of the tubing coupling as well as the field make-up procedures.

Given the system constraints, the API eight-round thread form was first examined. As shown in figure 1, this consists of a round thread form on a tapered pitch. As can be seen in the enlarged detail of the threads there is flow path in the root-crest clearance area of the thread both at the tube and coupling. In a 2-3/8" (60.32 mm) connection this results in two helical flow paths each 116 inches (285 cm) long. In order for this connection to effectively seal, these flow paths must be completely blocked at some point along their length. In addition, the thread flanks must have adequate bearing pressure to provide a metal-to-metal seal. Due to the configuration of the API eight-round connection, the nose of the tube may be plastic coated without compromising the quality of the seal. Additionally, the center, or "J" area of the coupling may be coated with a soft plastic allowing the nose of the tube to form a barrier to corrosion without hindering the efficiency of the connection.

The chief concern in utilizing an API eight-round coupling in CO_2 injection service is that CO_2 by its nature tends to destroy the thread lubricant. Once the thread lubricant has deteriorated sufficiently, it no longer performs its function of blocking the helical flow paths inherent in the connection and the connection fails in service. Due to the critical role of the thread lubricant in an eight-round threaded connection, careful attention was paid to thread lubricant selection. The two properties which were considered most important in thread lubricant selection were the ability of solids within the thread lubricant itself to seal off the flow passages in the threaded connection and the ability of the oil base to resist deterioration caused by contact with CO_2 at elevated pressure.

The primary mechanism employed by most thread lubricants in blocking the helical flow path is through the use of metallic particles which as the connection is made up deform to fill and block off these flow paths. In most low pressure liquid services, this method is quite acceptable. However, due to the nature of CO_2 injection at elevated pressures a in tighter block is required. We selected a high graphite, non-metallic thread lubricant, because unlike metallic compounds which tend to crush as they deform, the graphite has a tendency to shear along its crystal lattice resulting in finer particles which "fill in" the surface discontinuities of the thread flank nearly at a molecular level. These graphite particles are suspended in a lithium-based grease which is resistant to CO_2 degradation.

Connection Make-up

When determining proper connection make-up it is common practice to refer to API tables. However, these values were developed for use with API Modified thread lubricant at ambient temperatures. Since the thread compound selected was not an API compound, the determination was made to do further testing in an effort to establish the optimum make-up torque for the specific thread form / thread lubricant combination under consideration.

As stated earlier, the purpose of controlling make-up torque is to ensure that sufficient bearing pressure is obtained without damage to the connection itself. The method employed to determine this optimum torque consisted of installing strain gauges on the outside of the tubing coupling and on the inside of the tube. Both sets of strain gauges were cemented in place opposite the threads, and were continuously monitored while making the connection up at a constant speed of 1 rpm. A load cell attached to the back-up on the tubing tongs was utilized to continuously monitor the torque applied to the connection. These data were used to develop strain versus torque plots for both the tube and the coupling. Since a constant of proportionality exists between bearing pressure and strain, it was possible to perform a qualitative analysis to determine the optimum make-up torque.

Figure 2 illustrates a typical strain-torque curve for a 2-3/8 inch (60.32 mm) connection made up with a high graphite thread lubricant. Three distinct regions, each representing a separate type of mechanical process, are present. Initially, the coupling and tube undergo elastic deformation indicated by the relatively constant slope of the strain-torque curve. As bearing pressure gradually increases, the curve flattens out indicating that the energy imparted into the system is being used to deform the solid particles in the thread lubricant. Additionally, one would expect a certain amount of localized deformation due to point loadings on surface irregularities. For purposes of discussion, I will refer to this mechanism simply as local deformation. The third region is one in which minor increases in torque represent substantial increases in strain. This is attributable to gross deformation of the tube or coupling. It is in this region where "tight" becomes "too tight" and the integrity of the connection both in terms of sealing qualities and in terms of structural qualities is compromised. Additionally, in the case of a standard API eight-round thread form, it is the tube that invariably enters this region first. The consequence of this phenomenon is that plastic coating applied to the tubing may be in imminent danger of cracking or disbonding.

The same strain-torque curves were obtained utilizing an API eight-round thread form which has been modified to accept a seal ring made up with high graphite thread lubricant. The seal ring effectively blocks the flow path with a material highly resistant to CO_2 degradation (in this case Teflon), and the high graphite thread lubricant is used to form an effective secondary seal which is also resistant to CO_2 degradation. In order to best simulate actual running conditions, the "J" area of the coupling was coated with Ryton, as was done in actual injection tubing for corrosion protection. The resulting curve showed the familiar three mechanical processes along with an anomaly attributed to the pin penetrating the Teflon seal ring. There is, however, one important exception. The coupling enters the region of gross deformation at an unusually low torque as the tube remains in the region of localized deformation well past the point at which the coupling begins grossly deforming. Further investigation revealed that if the Ryton coating or the seal ring is omitted, or if a relief hole is drilled into the coupling in front of the seal ring groove, the connection make-up profile echos that of a regular API eight-round coupling.

The conclusion drawn from these data is that the seal ring and Ryton coating each effected a seal capable of containing the excess thread lubricant which is normally extruded during make-up, and that hydraulic forces exerted by the trapped thread lubricant were sufficient to cause a gross plastic deformation of the coupling.

In this application, given the forces expected to be acting on the tubing during the service life of the injection string, the anticipated loss in structural integrity of the connection (if any such loss actually existed) was deemed insufficient cause to reject the modified eight-round coupling design. Rather, this peculiar characteristic offers a significant advantage. Since the tube never enters into the region of gross deformation even after the connection is made up past the vanish cone (last scratch), it follows that the plastic coating integrity would not be compromised if torque limitations were inadvertently exceeded. Additionally, the presence of a Teflon ring forms a positive seal along the flow path. Finally, any CO_2 attempting to migrate along the threads would encounter tremendous hydraulic pressures and may thus be prevented from escaping.

Field Installation

In order to obtain accurate, repeatable, make-up torques during field installations, tubing tongs similar to those utilized in the strain gauge tests were used. The applied torque was continuously monitored by micro-computer and the tongs shut off automatically when the desired torque was reached. By maintaining very low make-up speeds (typically less than 1 rpm at final make-up) inertial effects of the tongs were minimized and accurate applied torque values were consistently obtained. The conventional method of utilizing the hydraulic pressure of the tongs to infer torque values was rejected as unreliable for several reasons. Changes in the physical properties of the hydraulic fluids make an accurate determination of torque from hydraulic pressure virtually impossible. Slight changes in hydraulic fluid temperature cause significant changes in system performance. Moreover, normal wear of the tongs render most hydraulic pressure versus torque correlations useless.

Additionally, the effects of rotary inertia cause inaccuracies. In monitoring hydraulic pressure the tongs are shut down when a preset pressure is reached. It is common for the tongs to be rotating in excess of 10 rpm at the time that this pressure is reached. The connection, already at full make-up torque, is used to stop the movement of the tubing and tongs. This "torque spike" is never displayed on the pressure gauge, but it is there in each connection.

Observation of field installations using the methods and equipment described above indicated that for a 2-3/8 inch (60.32 mm) API eight-round connections which were modified to accept a Teflon seal ring, optimum make-up torque was consistently achieved when the pin penetrated the coupling to within 0.125 inches (30 mm) of the vanish cone (last scratch). This indicated that the ultimate bearing pressure of the thread flanks could be correlated to final make-up position with acceptable accuracy. The end result was that the CO2 injection tubing could be installed using standard rig tongs by monitoring final position and limiting connection make-up speed.

The success of this type of make-up program relies on careful field supervision and adequate training of contract rig crews. A clear demonstration of the importance of this operation by company personnel by their on-site inspection of operations will be required. If this is not feasible, it may be necessary to engage specialized tubing make-up services and equipment.

Connection Testing

The final step required in the prevention of the migration of the injected CO2 into the tubing-casing annulus is the testing of each connection. During the development of the installation procedures, several types of testing were employed.

Internal testing with water, internal testing with nitrogen, and external testing with water all failed to detect potential points of CO_2 escape. By using helium as a tracer, detection of minute gas flows across the connections have been facilitated, allowing corrections to be made prior to returning the well to injection service. Also, the use of helium testing has facilitated the measurement of flow rates across the tubing connections.

Figure 3 shows a breakdown of the flow rates measured. Of those connections showing a measurable flow, 94.4 percent had flow rates of less than 1 * 10E-06 cc/sec. This is equivalent to about one standard cubic foot every thousand years. Flow rates this low are for all practical purposes undetectable using pressure decay techniques. One question that arose early in the helium testing program was "How much flow can we tolerate?". Due to diligent attention to connection make-up procedures, only 3.2 percent of the 3178 connections tested showed any flow and a specification of "no detectable flow" was judged appropriate. (Figure 4)

Another major point in the testing procedure is that it is not limited to the tubing connections. Every connection and seal in the injection string and bottom-hole assembly is helium tested. This includes the seals and threaded connections of the packer itself. Nothing may be overlooked.

The use of modified API eight-round couplings, high graphite thread lubricant, low speed controlled penetration make-up procedures and rigorous helium testing of all potential points of CO_2 escape, communication of CO_2 from tubing to casing can be eliminated, thus preventing external CO_2-related corrosion of the injection equipment.

Protective Coatings

During the development of the above tubing connection and field installation procedures, it became apparent that the plastic coating of the injection string is subject to damage by ordinary field handling techniques. Chipping of the coating during shipment and unloading frequently delayed wellsite operations. Routine field installation techniques utilizing standard rig tongs often cracked brittle plastic coatings available for use in CO_2 service.

Due to advances in the toughness of CO_2-resistant plastic coating, special tubing tongs are no longer required and the state-of-the-art in field handling and installation of plastic-coated tubulars is as it has been for the past several years. However, meticulous attention to detail is still required.

All plastic-coated tubing is handled only by fork-lift and is supported during transportation by wood stripping in at least three places equally spaced across the span of the pipe. All hold-down devices are secured only over the stripping. Thread protectors made of a steel jacketed plastic have virtually eliminated chipping of the plastic coating of the pin ends. Frequent inspection of the dies and heads of the tubing tongs for wear during the tubing run is required.

Testing a sampling of injection tubing which had been transported to location and installed using the above procedures, showed no coating defects. This indicates that in addition to preventing external corrosion caused by tubing-casing communication, the procedure developed should provide for superior protection from internal corrosion.

As with the tubing make-up procedures, the company supervisor must show by his on-site presence a dedication to running the injection string holiday-free. This is perhaps the most important facet of proper handling of plastic-coated injection tubing.

RESULTS

Of the six injection wells in which this procedure has been utilized, five have been complete successes. Continued application of the procedures developed are expected to result in the elimination of tubing-casing communication of CO_2 injection wells.

CONCLUSION

This methodical review and optimization of each of the major components of the downhole CO_2 injection equipment has lead to a state-of-the-art procedure which eliminates external damage of the injection tubing due to CO_2-related corrosion while maintaining the integrity of the internal plastic coating. The long range benefits are expected to be additional oil recovery due to lower operating expenses and longer equipment life.

ACKNOWLEDGMENTS

The author wishes to acknowledge the following for their invaluable contributions:

Mr. Trevor West, Weatherford Inc.
Mr. William Stringfellow, Weatherford Inc.

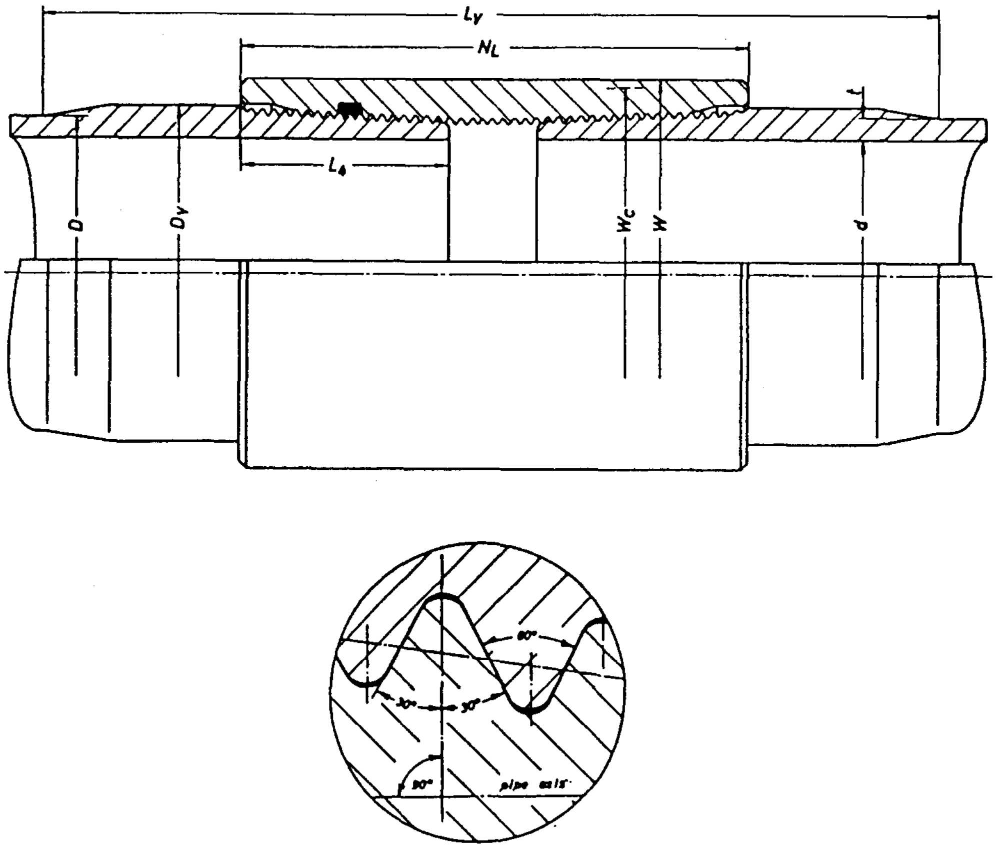

Figure 1 - Eight-round thread form

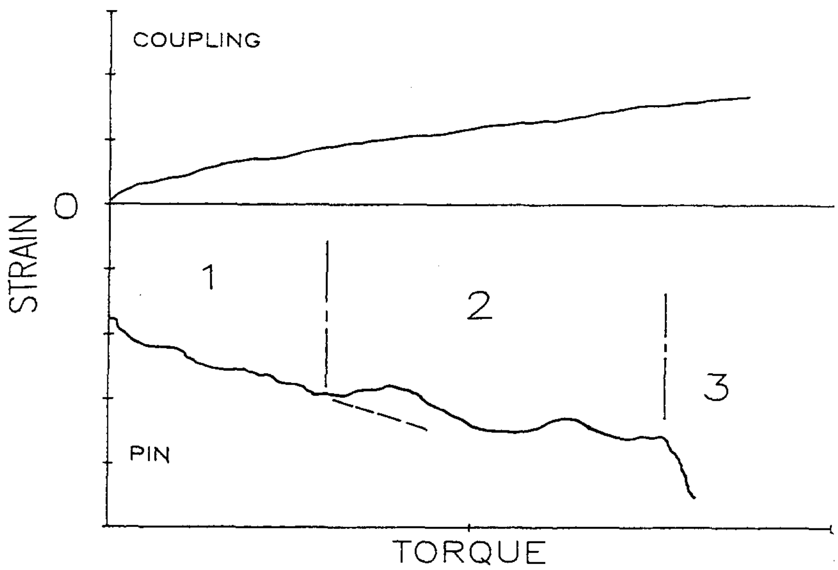

Figure 2 - Torque-strain relationship -
API eight-round connection

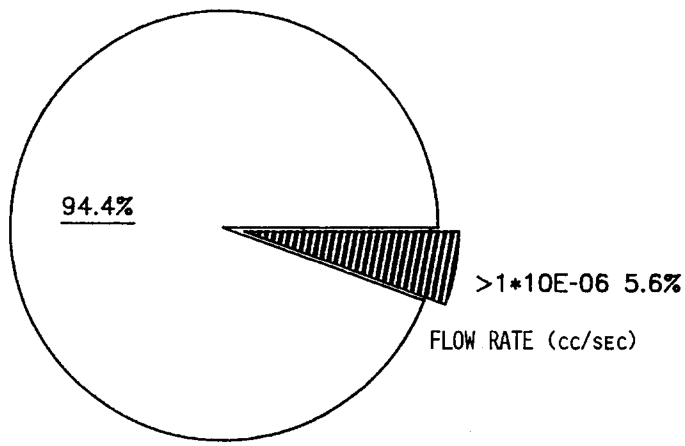

Figure 3 - Dollarhide Unit CO_2 injection - helium test results

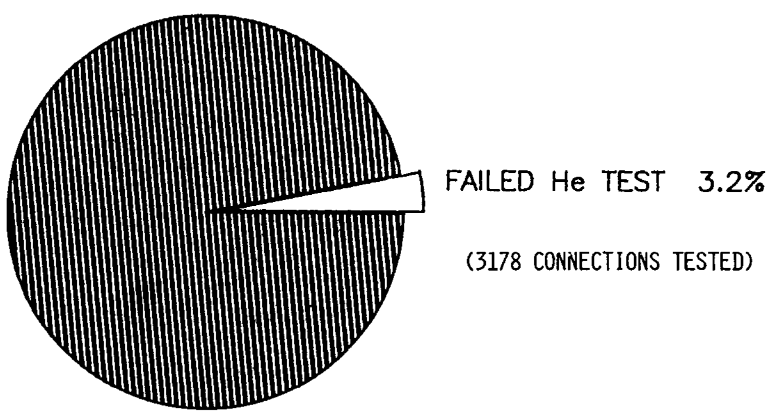

Figure 4 - Dollarhide Unit CO_2 injection - helium test results