COILED TUBING ROD STRINGS MAY EXTEND THE LIFE OF SPRABERRY WELLS (AND OTHERS) IN THE PERMIAN BASIN

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ABSTRACT

Spraberry operators in West Texas have been fighting casing leaks caused by the corrosive fluids in the San Andres formation for years. Water produced by the Dean, Upper and Lower Spraberry formations is disposed of into the San Andres.

There are possibly thousands of Spraberry wells that were drilled and completed without getting cement across the San Andres. This has resulted in plugging many of these wells. Spraberry wells will produce 5 –10 BOPD for decades, but when the corrosive waters from the San Andres cause casing leaks, it becomes uneconomical to continue producing these wells.

This paper will discuss the combination of slimhole conversion and the installation of a coiled tubing rod string system to solve the casing corrosion problems in wells that are usually considered P&A candidates. The development of the coiled tubing rod string system will be looked at. Case histories will also be presented.

INTRODUCTION

Low BHP is a problem and circulation across the San Andres has been difficult. Recently operators have pumped foam cement and gotten the San Andres covered. The San Andres is around 4500’ while the productive zones are +/- 7000’ to 9000’. Operators have also started using an external wrap on the casing string across the corrosive zone to provide corrosion protection. These completions have not been in the ground long enough to confirm that the external wrap will solve the corrosion problem.

After an “open floor discussion” on using coiled tubing for replacing conventional sucker rods at a monthly Trans-Pecos Section SPE meeting, Pioneer Natural Resources became interested in this new idea. Knowing that this technology was new and virtually unproven, Pioneer was willing to try this technology to extend the productive life of their wells.

CONCEPT AND SYSTEM SPECIFICS

The concept behind CTRS is to replace conventional sucker rods with coiled tubing and produce up the coiled tubing string (figure 1). This concept was originally developed in Argentina and was patented in various jurisdictions, including the USA and Canada.

An international oil producer and an USA based consulting firm were working to develop a method to complete slimhole wells in Argentina and came up with the CTRS idea. The ability to produce up the CT would allow them to greatly reduce the completion size requirement for the desired production rates. Another advantage was the reduction of completion components, since the CTRS functions as the rod and the production strings.

The CTRS system is comprised of coiled tubing string, pump and an anchor or mechanical hold down (figure 2). These components are run in the hole with a conventional coiled tubing unit. This is accomplished with one trip in the hole. The coiled tubing is hung off with a polished rod clamp above the bridle. The CTRS doesn’t require a polished rod; it extends through the wellhead and the stuffing box. The surface production package consists of fittings connected to the top of the CTRS, a valve and a flexible hose that connects to the surface flow line (figure 3). There is only one downhole connection in the CTRS system.

CASE HISTORY

Pioneer’s major objective was to find a permanent solution to the casing corrosion problems that result in the short production lives of their Spraberry wells. A CTRS system would allow them to convert the well to a slimhole completion and isolate the casing leak from the San Andres.

Pioneer selected a candidate that was drilled in June 1995. The casing leaks started in late 2001 and after several squeeze jobs it was determined that a slimhole conversion and a CTRS system was worth trying to save the well from P&A. The casing leaks were between 4352' and 4384'.

The rods and pump along with the existing 2 318" production string were pulled and the hole was cleaned out. A new string of 2 718" with turned down collars was run into the well's 4.5" casing with a Pump-Out Cement Sleeve and a Casing Packer on bottom (7000'). A corrosion protective wrap was placed on the new 2 718" liner from 6200' to 2200' (figure 4). It was expected that the San Andres water flow would prevent a good cement job across that zone.

A ball was pumped to activate the Pump Out Cement Sleeve. The ball lands in the lower seat, seals off the end of the liner and then pressure is applied to open the circulation ports allowing cement to circulate up the annulus. After the lead slurry was pumped, a wiper plug was pumped ahead of the displacement water. The wiper plug has an aluminum core and is pumped into the upper seat closing the circulation ports. A final applied pressure of 2500 psi over hydrostatic slides the sleeve down, shifting locking segments, allowing all internal parts to be pumped out of the tool(s) and into the wells rat hole.

Several unsuccessful attempts were made to pump out the internal sleeve before the top out slurry was pumped. After the top out slurry was pumped, further attempts were made to pump out the internal sleeve. As much as 5000 psi applied pressure was attempted without success. Without being able to pull the tool to determine the root cause, it is speculated that the symmetrical design and short length of the locking segments prevented the internal sleeve from being pumped out.

After the cement had time to setup, a coiled tubing unit with the CTRS and a motor was used to mill out the internal sleeve and the wiper plug. A swabbing unit was brought in to remove some of the San Andres water that had cross flowed into the productive zones when the old completion was pulled from the well. The zone was also chemically treated to prevent H_2S damage to the CTRS system to be installed. The CTRS was 100K material and not ideal for H_2S conditions.

Pioneer wanted to produce up to 150 bpd total fluid and 20 mcfd. The stroke rate desired was 8 strokes per minute (11,520 strokes in 24 hours) and the pumping unit on location was capable of an 86" stroke. Due to the stroke length, rate and Peak Polish Rod Load capacity of the pump (21,200 lbs.), 1.5" x 0.134" wall QT-1000 pipe was chosen for the CTRS.

The CTRS system comprised of 6,975' of coiled tubing and a 1.5" two stage insert pump with a mechanical valve. The mechanical valve was used as the lower traveling valve in the plunger to prevent gas locking the pump. A modified pump anchor was used to hold the pump in the 2 718" liner and
run below the pump. The anchor utilized an auto "J" system to activate the slips. Using a conventional pump anchor would require rotating the coiled tubing. The auto "J" anchor is run in hole in a pre-set position and set by simply picking up and setting back down. The anchor can be unset by picking up again, returning to the RIH position. This can prove to be a problem if the pump gets trash between the barrel and the plunger. Another factor that can cause the anchor to be picked up is "pump friction".

A "Pressure Activated Pump" was used. In this type pump the plunger is packed with API valve cups. This type plunger is designed to keep trash from building up and sticking the pump. The cups contract on the down stroke and expand on the up stroke. Any trash that gets between the plunger and barrel can be wiped to the top, preventing build up and sticking.

The pumpianchor assembly was run into the hole on the bottom of the coiled tubing. The coiled tubing was run through a straightener to remove the residual curvature common to coiled tubing. It took several attempts to get the anchor to set. When the anchor was set, the coiled tubing was cut and the pump was spaced out and hung in the bridal of the pumping unit. The coiled tubing was filled with water before it was run in the hole to minimize the time it would take to fill and to pre-stretch the CTRS.

After the system was rigged up to the flow line, the pumping unit was started and the system started producing fluid. Everyone was happy and went to the house. The following morning the pumper found the system not producing any fluid. **A** CT crane truck was brought to location to lower the pump plunger and "tag" the pump to knock free any debris. It was thought that trash was causing the pump to stick. A lifting elevator was used to lower the pump plunger and it was discovered that the anchor had unset.
The CTRS system was pulled and the pump was inspected to see if trash had caused it to stick. The pump was clean and it

was assumed that pump friction had caused the anchor to unset. The slip and hold down springs in the first anchor were found to be sized wrong causing them to fail. The CTRS system was run back in the hole with **6** sinker (weight) bars below the anchor to help overcome the pump friction. The total weight of the sinker bars was a little over 1000 lbs.

When the system was put back on production, nothing happened. The pump seemed to be tagging in both the up and down stroke. The system had to be pulled and the pump inspected again. When the anchor was pulled out of the top of the production "T", it was discovered that the anchor's mandrel had parted in the lower section of the "J" grooves. The sinker bars had dropped to the bottom of the well.

Another anchor was needed and after looking at a couple of designs, one with a greater slip area was chosen and run in the hole. The new anchor worked the same way as the first anchor. It was an auto "J" system with a mandrel that had a heavier wall and longer than the previous style. The anchor was tested a few times while the system was being run back into the hole. The new style anchor was successful.

The CTRS system ran without interruption for four months at 9.6 SPM with an 86" surface stroke. From the beginning, the pump efficiency was low for a new pump and after just a few weeks of operation, pump efficiency had dropped about 20 BPD of total fluid. The system was analyzed and because a tube was used, as opposed to solid rods, analysis of the system was difficult. Indications were that the standing valve and possibly the traveling valve had been leaking since start up. This was not a surprise since the well had been pumping under a packer for five months because of the non-repairable casing leaks. When the packer was released and the rod system pulled a substantial amount of dirty water was dumped from the San Andres. Chlorides and H_2S were present for some time.

At the end of four months the system stopped producing. **A** fluid pump was used to pressure test the system, determining that a leak had developed somewhere within the system. The CTRS had to be pulled to find the leak. The pump's hollow pull rod was suspected because it was the weakest part of the configuration. Another component that was suspect was the coiled tubing to pull rod connector.

While the CTRS was being pulled, a crack was found in the coiled tubing at 180' from surface. The crack was noticed when it opened as it passed over the gooseneck. The crack propagated through the entire tubing wall for approximately an inch around the perimeter of the pipe. To repair the crack, a welder was called to location. The failure would have to be cut out and the pipe welded back together in order to pull the rest of the system out of the well.

During preparation for the weld, a second crack was found below the injector head, about 30' from the first crack. There had not been any fluid observed leaking from either crack, but when the pipe was cut below the second crack, the rest of the coiled tubing was found standing full of fluid. This observation indicated that the pump's valves were more than likely holding and there probably weren't anymore cracks in the pipe remaining in the hole. This was an indication that embrittlement, caused by H_2S, may not have been a problem. If embrittlement had been a problem, finding more cracks would have been expected.

The decision was made on location to abandon the CTRS project and run a conventional rod pump system. This decision was based on concerns raised while visually inspecting the pipe as it was pulled out of the well. The remaining 6,600' of pipe was pulled out of the hole without finding other cracks. However, wear was noticed and observed to be excessive in the lower portion of the pipe. Stress fatigue, due to overloading, was suspected as well. If these concerns were valid, then running the CTRS back into the hole would have resulted in continuing problems.

To find the root cause of the pipe failure, both failures and pieces of the pipe between the failures were sent to three different labs to be analyzed (figure *5*). Also an independent ultrasonic inspection was conducted on the rest of the pipe that was pulled from the well to determine the amount of wall loss due to any wear while the CTRS system was in operation.

The ultrasonic inspection determined that the wear was not as significant as first anticipated (table 1). The results from the three different labs were not as clear-cut. Each lab had a different opinion as to why the failures occurred. Pioneer sent the bottom failure to a local metallurgical lab and the top failure was sent to the pipe manufacturer that had milled the CTRS.

The local lab concluded that the bottom failure was caused by "hardness variations that produced uneven stresses resulting in a fatigue fracture". This analysis noted that chemical testing for H_2S exposure was conducted and produced negative results for both the interior and external surfaces of the pipe.

The top failure was sent to the manufacturer for analysis. The manufacturer concluded that the only possible explanation was that since the 2 7/8" slimhole liner was set in compression, the CTRS was being bent repeatedly over a section of the liner that was slightly cork-screwed resulting in a small but cyclic bending moment. During the four month period the CTRS would have cycled more than 1.4 millions times at an average stroke rate of 9.6 SPM. The suspected bending moment applied more than 1.4 million times as the forces in the tubing changed, could have caused the transverse cracking. The manufacturer also noted that "observations of the edges of the transverse crack indicated that there were no imperfections at the crack origination point that could have caused a severe loss of pipe life". The manufacturer did note that further cleaning of the fracture face and analysis with scanning electron microscopy might be more revealing. There was no mention of embrittlement caused by H_2S or of corrosion being a contributing factor to the failure.

Both samples from the local lab and the manufacturer as well as two 5 foot sections from each end of the pipe between the cracks were sent to BJ Services' Coiled Tubing Research and Engineering facility in Calgary, Alberta, Canada. Again, different conclusions were found. Some conclusions about the top failure (figure 6) were:

1. The CTRS failure occurred due to a corrosion fatigue rupture initiated from a relatively large external gouge defect (figure 7) while in an oxygenated chloride and sulfur aqueous environment.
2. The macro and micro hardness measurements indicated a wide spread in hardness of the ERW weld in the tubing. The Rockwell C method indicated HRC 19 and the micro hardness VHN 300g and Vickers 10kg methods indicated hardening up to HRC 27 at the center of the ERW weld (table 2).

The lower failure (figure 8) that had been analyzed by the local lab had similar conclusions:

1. The CTRS failure occurred due to a corrosion fatigue rupture initiated from a large external stamp-like defect (figures 9 & 10) while in an oxygenated chloride and sulfur aqueous environment.
2. The pipe was degraded by a moderate external and internal general corrosion, which did not cause any localized or random pitting.

Secondary fatigue cracks were also found (figures 11 & 12) and to have originated at the deformation dished depression in the OD surface. The jagged profile of the secondary crack contained branching with a corrosion film, inferring that the fracture occurred due to a corrosion high fatigue mechanism.

It could not be determined if the external defects, from which the cracks initiated, were induced prior to being milled into a tube or after the pipe was delivered to the end user.

DISCUSSION AND CONCLUSIONS

Pioneer's chosen candidate was the deepest CTRS installation to date. Most goals were achieved or at least partially achieved. A lot was learned from the mistakes encountered during this project.

- The string was milled using one wall thickness. A tapered string should be considered at the depth in this case study.
- The CTRS system was run into the hole three times and through the straightener the same number of times. The three trips into the hole induced 18 stress reversals on the CTRS. The pipe straightener reverse bends the pipe to eliminate the residual curvature. These events contributed to accelerated pipe fatigue.
- The stroke rate was another contributing factor to the early failure of the pipe. Slower stroke rates would reduce high cycle stress on the CTRS just as it does for conventional rod strings. The authors of this paper believe that the lessons learned from conventional rod pumping should be applied to this new concept. In conventional rod pumping it has been known for many years that long strokes and slow pumping speeds reduce the number of stress reversals applied to the rod string. With CTRS a larger pump plunger can be used to reduce the pumping speed without the need for increased horsepower or torque.
- Another consideration is a lower volume candidate if slower pump speed and/or longer pump stroke are not an option.

The significant results of this project were:

- Wells that still have an economic life can be saved from plugging by converting to slimhole.
- The optimum method for pumping wells converted to slimhole is still to be determined.
- Slimhole liners should be cemented while in tension.
- An anchor that can be manipulated with coiled tubing was found and tested. The anchor will eliminate early fatigue due to excessive stresses induced by having to run and pull the CTRS multiple times.
- A need exist for good design and operations analysis software.

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Table 1
Results of Ultrasonic Inspection

	Outside Diameter			Thickness		
Depth (ft)	Max (in)	Min (in)	Ovality	Max (in)	Min (in)	Difference
DH End	1.532	1.499	0.033	0.178	0.139	0.039
64	1.520	1.500	0.020	0.134	0.124	0.010
87	1.540	1.510	0.030	0.134	0.134	0
129	1.530	1.500	0.030	0.139	0.133	0.006
152	1.560	1.500	0.060	0.139	0.131	0.008
285	1.520	1.498	0.022	0.139	0.132	0.007
802	1.510	1.500	0.010	0.138	0.13	0.008
1887	1.570	1.500	0.070	0.143	0.136	0.007
3902	1.579	1.500	0.079	0.139	0.132	0.007
4906	1.520	1.496	0.024	0.135	0.132	0.003
5218	1.543	1.499	0.044	0.136	0.132	0.004
5318	1.517	1.496	0.021	0.134	0.127	0.007
5422	1.538	1.503	0.035	0.134	0.134	0
6003	1.540	1.493	0.047	0.134	0.129	0.005
6690	1.521	1.499	0.022	0.131	0.129	0.002
6694.5	1.526	1.497	0.029	0.13	0.129	0.001
6695	Weld Repair Location					
6695.5	1.533	1.495	0.038	0.132	0.130	0.002
6720	1.522	1.504	0.018	0.129	0.128	0.001

Table 2
Hardness Test Results

Rockwell hardness across the seam weld														
Distance (mm)	-10				-3			0*			3				10
HRC	22				19			19			19				21
Microhardness Vickers 300 gram across the seam weld															
Distance (mm)	-10	-7.5	-5	-4	-3	-2	-1	0*	1	2	3	4	5	7.5	10
VH	265	254	252	252	249	260	263	281	257	252	252	261	263	269	263
HRC (Conversion)	24.5	23	23	23	22	24	24.5	27	23.5	23	23	24	24.5	25.5	24.5
Vickers 10 kg hardness results															
Distance (mm)	-10	-7.5	-5	-4	-3	-2	-1	0*	1	2	3	4	5	7.5	10
10kg	260	258			255	252	265	272	251	254	242			257	257
HRC (Conversion)	24	23.5			23	23	24.5	26	23	23	20.5			23.5	23.5
* ERW fusion line															

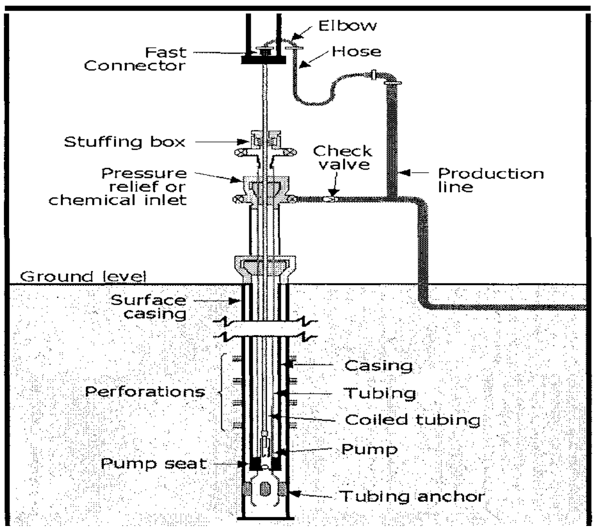

Figure 1 - CTRS Completion

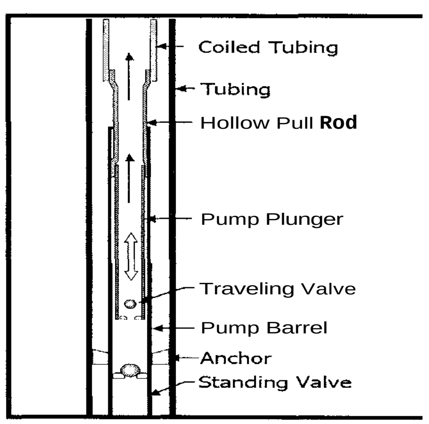

Figure 2 - CTRS Downhole Components

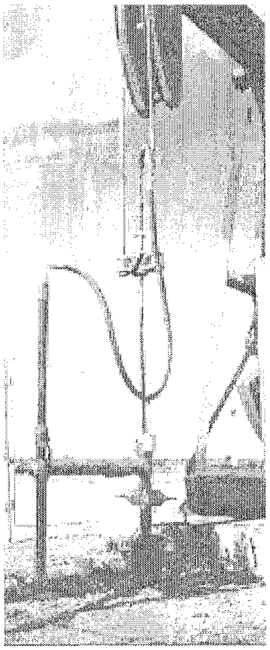

Figure 3 - Surface Components

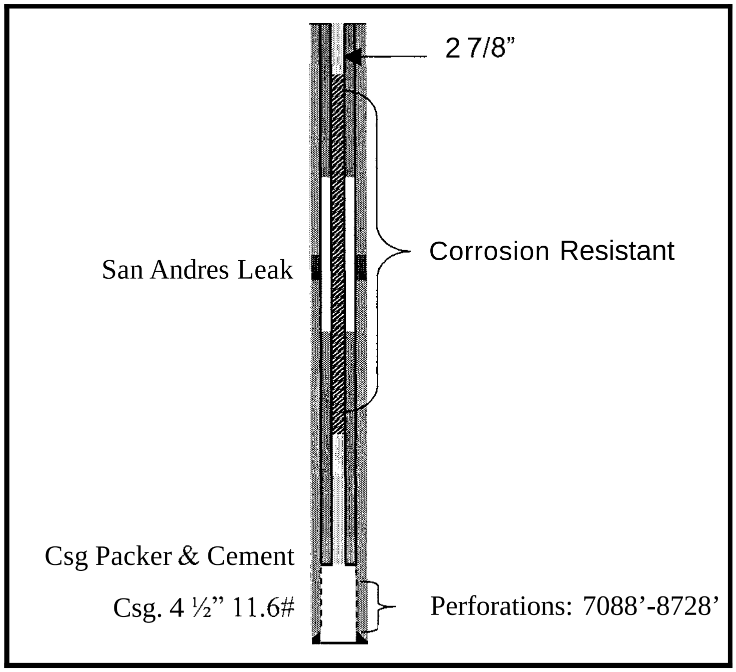

Figure 4 - Slimhole Conversion For CTRS

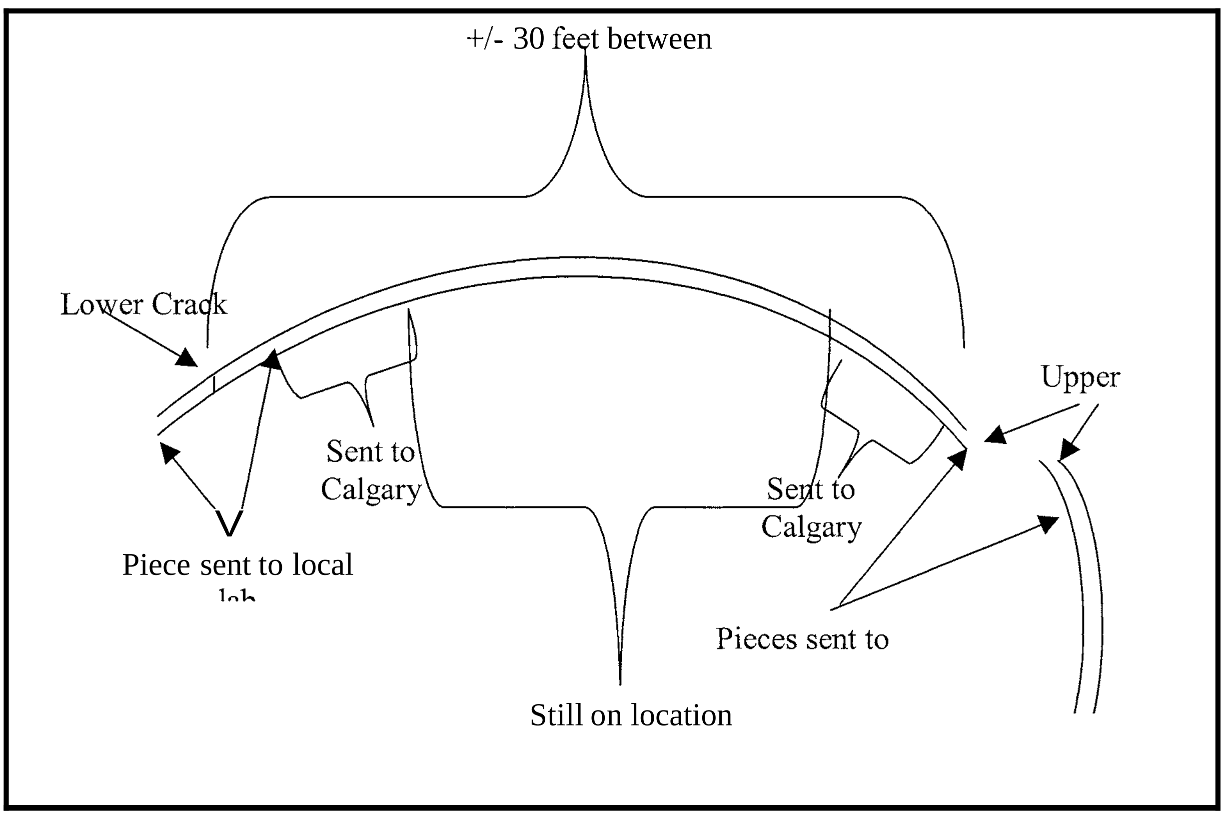

Figure 5 - Sample Collection For Testing

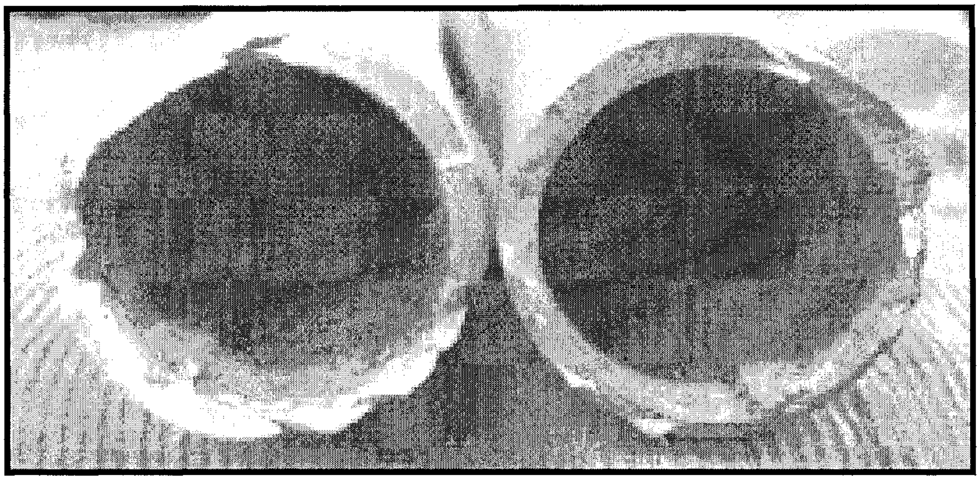

Figure 6 - Top Crack After Opening Up Going Over Gooseneck

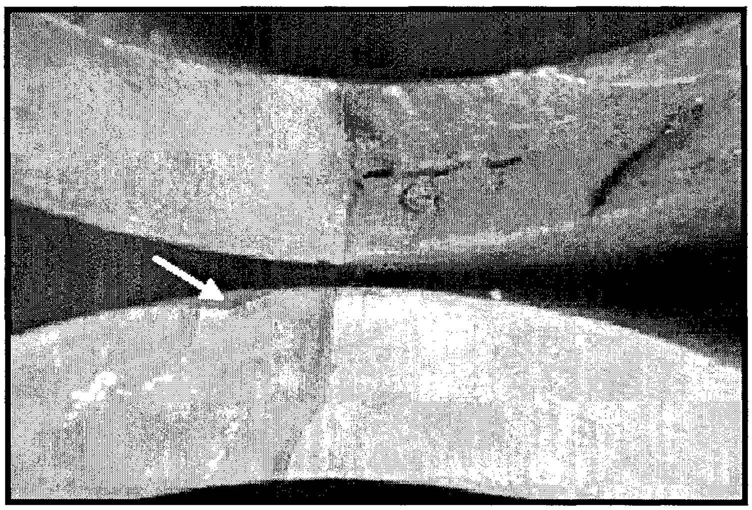

Figure 7- Detail Of Fracture Surface and External Gouge at Initiation Point

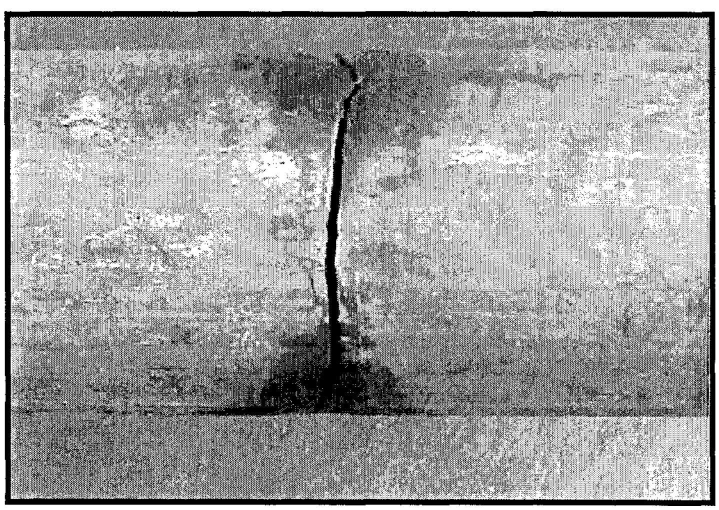

Figure 8 - Lower Failure

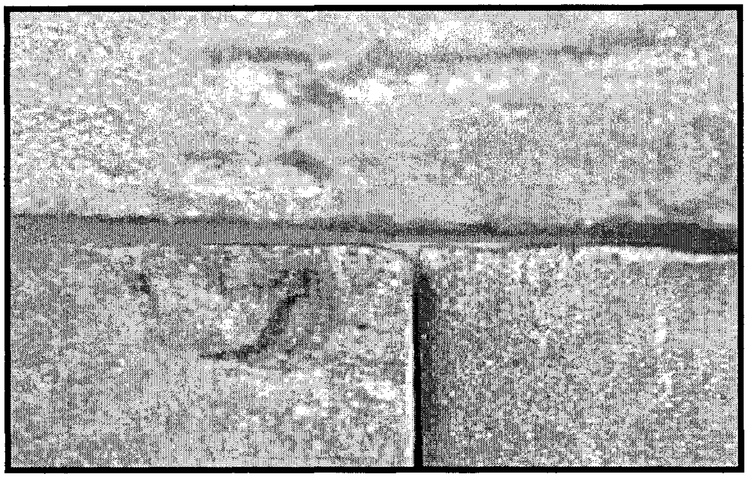

Figure 9 - Stamp-Like defect at fracture Initiation Point (OD view)

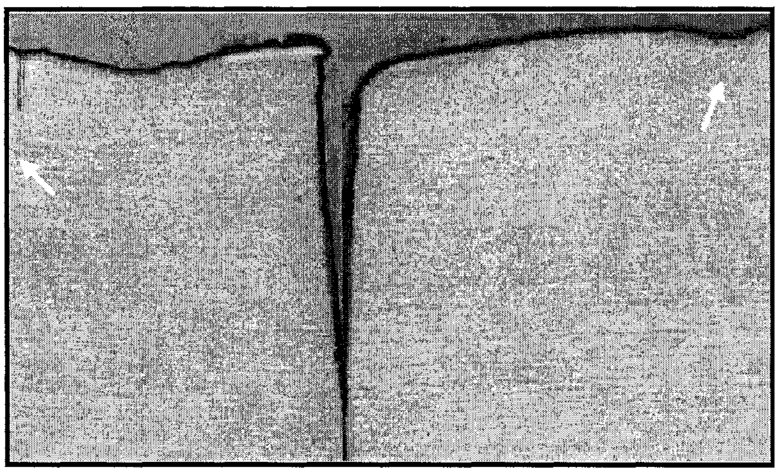

Figure 10 -Detail Of Fracture Initiation Showing Secondary Crack and External Defects

Figure 11 - Detail of Secondary Cracks

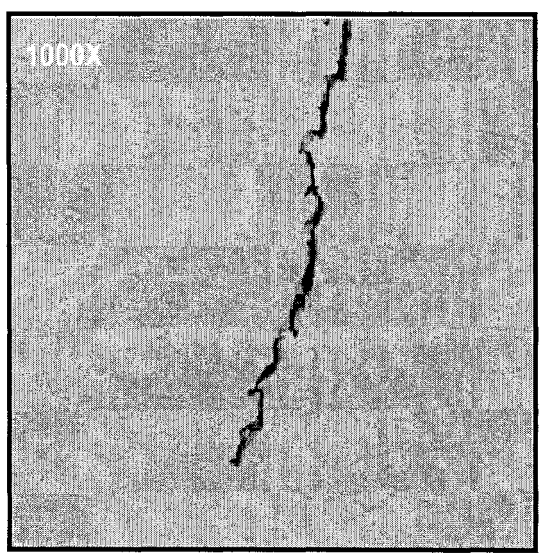

Figure 12 - Detail Showing Tight Fatigue Propagation w/ Corrosion Scale