

FAILURE INVESTIGATION OF CAPILLARY TUBING (ASTM 316L) USED FOR CALCITE INHIBITION

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ABSTRACT

A failed capillary tubing (ASTM 316L) used for injection of calcite anti-scalant chemical was investigated. Results of microscopic, petrographic and SEM EDAX analysis suggest that the capillary tubing was subjected to stress corrosion cracking (SCC). The cracking is preceded by localized pitting corrosion. The local corrosive environment leading to cracking is rich in chloride. Sulfur compounds are also present and there may be a contribution of sulfide to the SCC. The presence of chloride, sulfur and other elements (Ca, Al, Si, K) suggest that the pitting and cracking occurred in contact with geothermal fluids. The results of the investigation do not clearly define the time of cracking. However, there is strong evidence that the pitting occurred in well SP-4D. A moving area of flash zone, which crossed the area of final failure, induced this. Periods of failed inhibition (when the flash point was below the injection point) in SP-4D caused the deposition of calcite in the tubing. The calcite deposits provided crevice areas for the concentration of chloride on the tubing surface where pitting occurred. Final failure of tubing occurred during pull-out of the used tubing from well MO-2. Several mechanisms for SCC in geothermal environment are outlined. Detailed analytical work, history and postulated sequence of events leading to final failure are discussed. Action plans to avoid similar failures in capillary tubings in service to calcite inhibition systems are forwarded.

1.0 INTRODUCTION

A two-meter sample of a broken capillary tubing was brought to the Materials Performance Technologies (MPT) laboratory, as trial specimen for failure investigation. The tubing broke at 230 meters at the second pulley during pull-out operations from well MO-2. The

damaged portion of the capillary tubing was about 5 meters. After fishing operations, the recovered tubing below the parted portion appeared to be intact. No pitting and corrosion indicators are visible. Similarly, the upstream portion of the tubing also appeared intact. It was in well MO-2 for a period of only 14 hours (from 1400H of 09/16/00 to 1000H of 09/17/00) as the injection system for a calcite inhibitor chemical. The premature pull-out of the tubing was conducted due to operational constraints that required the immediate shutting of well MO-2.

Prior to service in well MO-2, the capillary tubing was the injection tubing for the calcite inhibition system (CIS) in well SP-4D. It was in service for a year (from May 1999 to May 2000), and was recovered intact. It was spooled and kept in storage at the MGPF warehouse from May, 2000 to September, 2000. Before shipment to Manito, the spooled tubing was pressurized with water to check integrity of tubing (leak test). No leaks were reported during this period.

The main objective of this report is to conduct a failure investigation of the capillary tubing. The results of the investigation and analytical work were used to deduce the chronology of events leading to final failure. Finally, recommended action plans to avoid similar failures in the future for capillary tubings in service to calcite inhibition systems are forwarded.

2.0 FAILURE ANALYSIS OF CAPILLARY TUBING

2.1 Reported History of Failure

The damaged capillary tubing was initially in service at well SP-4D, MGPF from May 1999 to May 2000. The tubing was recovered intact from well SP-4D. Prior to pull out, the chemical inhibitor inside the tubing was flushed with water to clean the inside of the tubing. The tubing was

stored in a 20" spool for 3 months (May to September 2000), inside the winch truck parked at the MGPF, warehouse. The spooled tubing was again purged with water prior to being moved to MO-2, Manito Livelihood Geothermal Project.

No problems were encountered while the tubing was being rolled out. The tubing went into well MO-2 between 1400 –1600 hours on September 17, 2000, and was pulled out of the well the next day at 1000H. The tubing was pulled out due to outside problems related to the power plant and re-injection failure and not to the injection system. The tubing broke while it was being pulled out from well MO-2. Based on winch depthometer reading, the tubing failure was at 230 meters from the sinker bar end. Breaks occurred over the top pulley at the winch and one separated section fell back into the well, while some sections remained on the surface. The length of the damaged portion was about 5 meters.

There was no evidence of abrasion, which might have led to mechanical failure. The failure is characterized by pitting, corrosion and near circumferential breaks with associated material bulges. The damaged sections are "brittle" in comparison with the rest of the exposed tubing.

2.2 Mechanical and Physical Properties of Capillary Tubing

The capillary tubing has a total length of 1100 meters with an OD of 0.25 inch (6.35mm) and ID of 0.18 inch (4.572 mm). This type of capillary tubing has been extensively used by Oxbow Power Services in their calcite inhibition systems at Dixie Valley, USA. This tubing, an excess from their supply in 1998 was donated to PNOC-EDC for use at the MGPF calcite inhibition system (CIS). The mechanical properties of the capillary tubing were assumed to be similar to the tubing presently being used at other PNOC-EDC calcite inhibition projects (Table 1). This tubing arrived without any clear specifications during shipment.

An 85 kg sinker bar (weight in air) was placed at the end of the capillary tubing. The actual weight recorded within well MO-2 was about 65-70 kgs while the well was flowing.

Stainless steels have a high corrosion resistance, high temperature strength, oxidation

Table 1. Mechanical properties of PNOC-EDC CIS capillary tubing.

Sandvik 3R60, ASTM 316L
Austenitic stainless steel
%C<0.03, %Cr=17.5, %Ni=13,%Mo = 2.6, PRE=26, PRE+0.33*%Ni = 31
Mechanical strength= 220 Mpa, min
Tensile strength =515-690 MPa
Elongation = 45%, min
Yield Strength = 316 kg pull

resistance, good ductility and chemical resistance. Improved chemical resistance is obtained by addition of Molybdenum as in the Type 316. Corrosion phenomenon in stainless steels and related chromium bearing alloys are largely a function of the phenomenon of passivation. This passivity is a result of the presence of an invisible oxide film. The passive film is very thin. Stainless steels are usually in the passive condition except when freshly scratched or abraded.

The type 316 has been selected for industrial environments because of the performance edge afforded by the molybdenum against chloride contamination. When chlorides are present in an industrial atmosphere, they may lead to more intensive attack on the stainless steels. If the deposits are not washed, these may be sufficiently hygroscopic and corrosive to lead to localized attack. A value known as the pitting resistance equivalent (PRE), which varies slightly among various groups of alloys, may be calculated as a first approximation of chloride resistance.

$$PRE = \%Cr + (3.3*\%Mo) + (16*\%Ni)$$

The calculated PRE for SS316 is about 26. Higher PRE's are correlated with improved resistance to both pitting and SCC. *A minimum PRE of 40 is recommended for sea water service.* The resistance of stainless steels and nickel base alloys to SCC in aggressive Cl media has long been recognized as being a function of nickel (Ni) content of these alloys. With this consideration a revised PRE of (0.33*%Ni + PRE) has been introduced. Susceptibility to SCC of stainless steels is most pronounced at 8 to 12% Ni and decreases at higher or lower levels. Above 42% Ni the

austenitic materials are immune to cracking in many industrial environments. With these considerations, the SS316 tubing is expected to be highly susceptible to pitting and SCC in a geothermal environment.

2.3 Visual Examination

Visual examination using an optical microscope showed pits and cracks concentrated on the inner curvature of the tubing (Fig. 1). This is typical of a tubing which has been run through a pulley. The pits are shallow spherical holes in random clusters occupying ~3% of the total surface area of the tubing (Zaide-Delfin, 2001). The pits have an average diameter of ~0.8mm and a depth of ~0.14mm (Zaide-Delfin, 2001). They are mostly concentrated on the inner curvature of the tubing, although a few cracks and pits are also found on the outer curvature.

The cracks are crevices oriented perpendicular to the length of the coil tubing (Fig. 2A), associated with corrosion pits. The cracks propagate from the pitting corrosion. Some cracks are wide open and show that they have penetrated or breached the tubing wall. The length of the wide cracks is from ~4.0 to 5.0 mm, with width of about ~0.5 mm (Zaide-Delfin, 2001). Most of these open cracks are located in the inner curvature as the tubing is pulled in a pulley. This is the area of compressional stress.

Gray to black corrosion products with whitish scales are found within the pits. Adherent reddish brown corrosion stains are very visible in the uncorroded areas close to pits and cracks (Fig. 2).

2.4 Microscopic Analysis

A 2-inch section of the capillary tubing was cut longitudinally parallel to the weld. It was cleaned ultrasonically and then investigated under the microscope. Microscopic analysis of the weld shows that it is intact. This suggests that the cracking was not due to weld failure. In fact, most of the cracks are on the opposite side of the weld.

Thin section analysis of the parted tubing show that cracks are propagating from outside the tubing. Cracks were always associated with localized pitting corrosion (Fig. 3). Cracks seen on the surface of the tube form a branching pattern typical of stress corrosion cracking

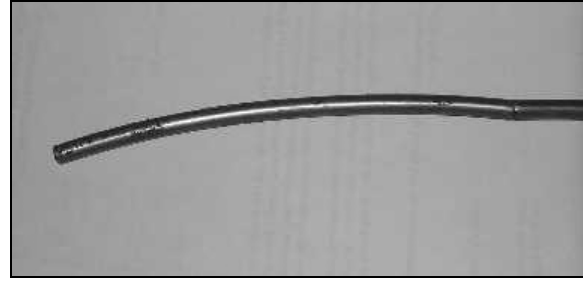


Figure 1. Damaged portion of the capillary tubing showing the pits cracks and corrosion products concentrated on the curved side.



Figure 2. Closer view of the opened cracks which penetrated the tubing and the pits with associated corrosion products.

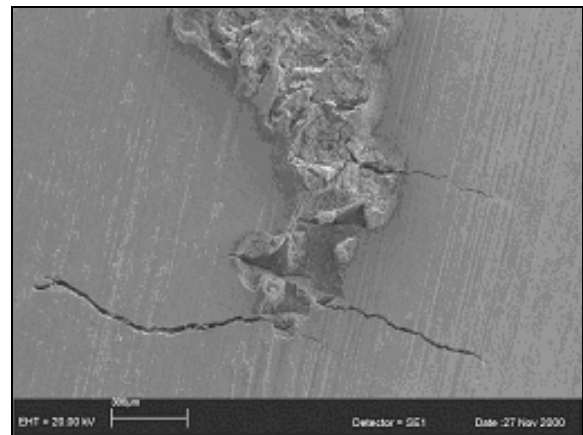


Figure 3. Localized corrosion pit with cracking originating in the pit and first stages of propagation into the un-corroded material.

(SCC). Multiple cracks were seen from most pits but some pits had not yet caused cracking (Fig. 4). Crack opening was primarily by plastic deformation. Finer cracks emanating from the inside of the tubing are just starting to show. However, these finer cracks have not

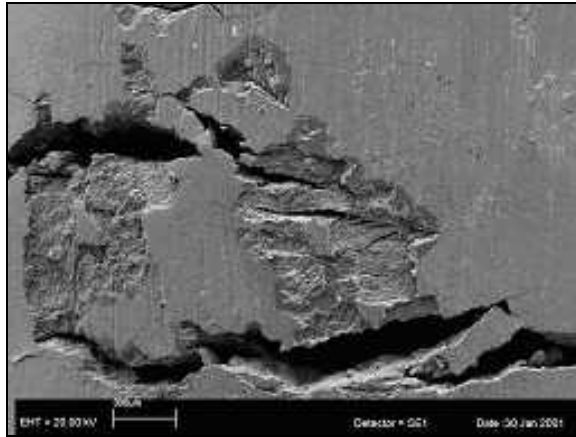


Figure 4. Multiple cracking in localized corrosion pit, with cracks opened by plastic deformation.

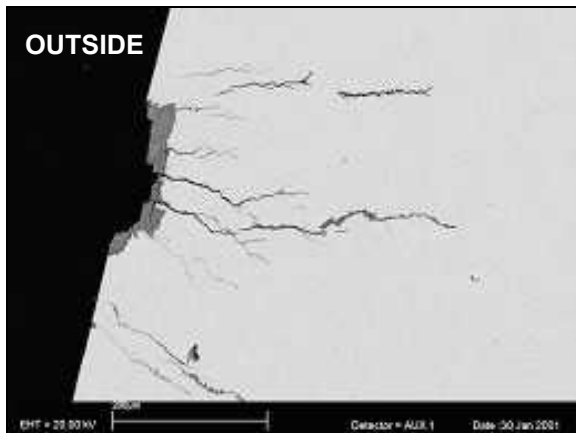


Figure 5. Cross section showing multiple branched cracks originating from corrosion pit.

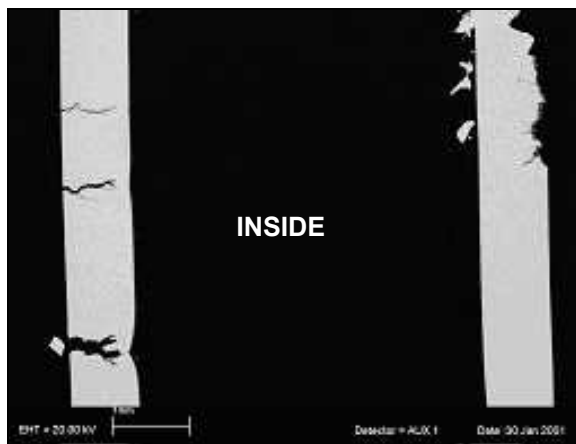


Figure 6. Cross section showing opening crack with plastic deformation on the internal surface.

yet breached the tubing wall. This further suggests that the inhibitor solution (a 10% neutral polyacrylate solution), which passes through the inside of the tubing, did not initiate the failure. Major damage is attributed to cracking from outside.

Scanning Electron Microscope (SEM) examination and Energy Dispersive X-Ray Analysis (EDAX) of the corrosion products present was conducted at the MPT Laboratory. Optical examination revealed that there is minimal corrosion on the inside surface. The cracking was initiated from the outside surface, with multiple cracking occurring from single pits (Fig. 5). Crack opening was primarily by internal plastic deformation at the time of final failure (Fig. 6) indicative of high temperature conditions.

EDAX analysis of the corrosion product present on as received samples at three locations are shown in Table 2.

The EDAX analysis suggests that major corrosion product found in pits is chromium oxide (Cr_2O_3), formed under high temperature conditions. Both Fe and Ni are low indicative of possible dissolution of these corrosion products. The presence of chloride, sulfur and other elements (Si, K, Ca) suggest the pitting and cracking of the tubing occurred in contact with a geothermal fluid.

Petrographic analysis of the corrosion products have identified black magnetite (Fe_3O_4) minerals, found on the surface of pits; while hematite (Fe_2O_3) occurs as reddish brown stains on the surface of the tubing close to the cracks (Zaide-Delfin, 2001). These corrosion products are usually encountered only in oxygen rich environments. Under near neutral conditions the stable corrosion product formed is usually magnetite (Lichti and Braithwaite, 1980). Experiments by Soylemezoglu and Harper, 1982 in aerated steam tests of carbon steel at Broadlands, only formed hematite in significant levels at abnormally high levels of O_2 (about 2.5 g/L). These O_2 levels are not found in high temperature (180°C - 240°C) geothermal wells. The oxygen solubility curve (Fig. 7) clearly show that dissolved O_2 levels in water at high temperature is almost nil. It is believed that if magnetite and hematite were formed only under moist conditions of atmospheric or air contamination, outside the geothermal well

Table 2. SEM EDAX analysis of corrosion products on as received samples with results in Element Weight%.

#	O	Al	Si	S	Cl	K	Ca	V	Cr	Fe	Ni
1	31.82	0.24	1.18	4.79	0.82	0.46	0.49	0.51	57.47	1.74	0.50
2	38.17	0.16	0.69	4.86	0.60	0.57	0.47	0.45	50.78	2.23	1.02
3	34.89	0.08	0.78	4.68	0.94	0.55	0.27	0.17	55.17	1.81	0.65

Table 3. SEM EDAX analysis of corrosion products on as received samples with results in Element Weight%.

#	O	Al	Si	S	Cl	K	Mn	Mo	Cr	Fe	Ni
1	63.86		0.19	1.07	3.48		0.31		2.36	27.20	1.53
2	63.56	9.41	14.72	3.44	1.77	0.63			0.99	4.99	0.48
3	67.90		0.86		0.62		0.29	2.66	22.39	4.14	0.83
4	65.50		0.68		0.16		0.43	2.45	26.53	3.21	1.18

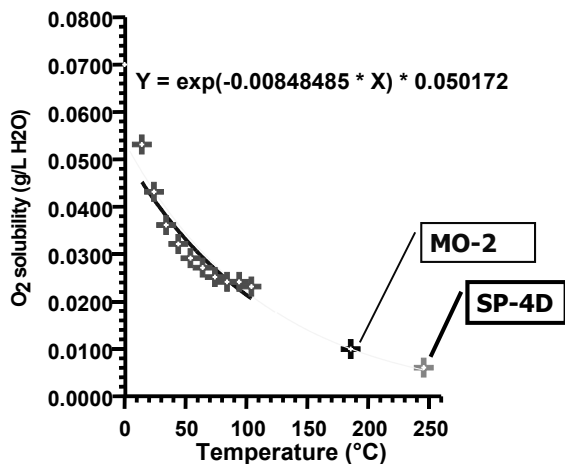


Figure 7. Solubility curve of oxygen in water at various temperatures with P=750mmHg (Data from NACE Corrosion Engineer's Reference Book, 1983; Ed. By R. S. Treseder)

environment. It is likely, that this condition was encountered during storage and transport of the tubing.

Scale deposits identified were weak amounts of white drusy calcite (CaCO_3) crystals in one of the big cracks (Zaide-Delfin, 2001). Rare whitish cubic minerals are also observed inside the cracks. These isotropic cubic crystals are likely salts of halite or NaCl (Zaide-Delfin, 2001). These scale deposits from geothermal fluids suggest that the tubing may not have been completely dried before storage. Another possibility is that calcite was deposited on the tubing at this portion, inside the well. However, halite is highly soluble and could only form under evaporative concentrations as the water dries or during flashing.

The same sample as analyzed at EDC was brought to MPT New Zealand for SEM EDAX analysis, as it was not consistent with earlier MPT findings. The results of the analysis are shown in Table 3.

The EDC prepared cross section was indeed rich in Fe/O and initial optical identification was confirmed by the SEM EDAX. However, inner products are predominantly chromium oxide with low levels of Fe and Mo. It should be noted that both EDAX analysis (Tables 2 and 3) show the presence of significant concentrations of Al and Si suggestive of the presence of silica and/or aluminum silicates. The concentration of Cl is higher in the outer area but is present in all the layers.

2.5 Environment

Next we look at the geothermal environment of the capillary tubing. Although the failure occurred during pull-out in well MO-2, its service period is too short (14 hours) to be the culprit in the catastrophic failure. The cracks were too deep and numerous to have been initiated in this short exposure period. Tests conducted on SS316 to evaluate susceptibility to failure by SCC in worst case aerated geothermal steam environments have shown SCC to occur in periods ranging from 52-63 weeks (Lichti et al., 1995).

Review of the downhole well profile of MO-2 shows two feed zones at 500-600 mMD,- with major feed zone at 900-1000 mMD (Fig. 8). Both zones have close to neutral reservoir pH (6.4) waters, calculated DO levels of 0.01g/L H_2O , Ca of 200-400ppm, Cl levels of 2,000-6,000 ppm, SO_4 levels of 50-70 ppm, $\text{H}_2\text{S}_{\text{TD}}$ and CO_2_{TD} levels of at 0.57 (or 10.8 ppm) and 41 (or 729 ppm) mmols/100 moles steam, respectively.

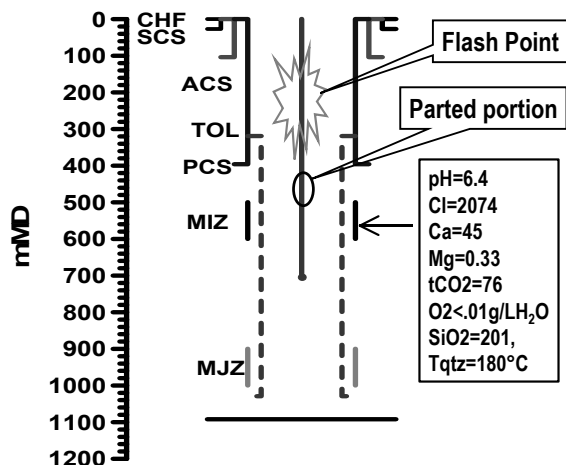


Figure 8. MO-2 well profile showing the location of feed zones, flash point depths, injection tubing and relative position of the parted portion of tubing inside the well.

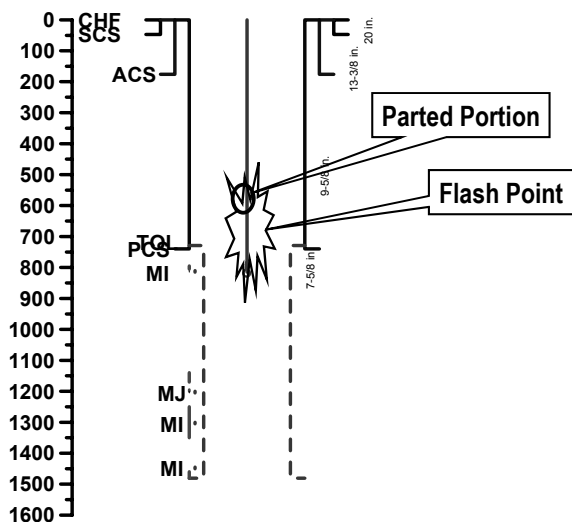


Figure 9. SP-4D well profile showing locations of permeable zones, flash point depths and injection tubing with relative position of parted section inside the well bore.

The very low DO levels (Fig. 7) in the high temperature environment ranging from 180°C to 210°C, would discount oxidative corrosion. Acidic corrosion, which results in more aggressive intergranular attack (H_2 cracking from $2H^+ + 2e^- = H_2$) is also not possible. Acid conditions at 180°C occurs only at $pH < 5.67$, a condition definitely not present in the wellbore. Fast and catastrophic failure of SS316 is not expected in this type of environment.

In well MO-2, the flash point occurs at 100-400 mMD under variable well head pressures.

However, under full bore conditions, the flash point is expected at a shallower level of 100 mMD. Tubing breakage is coincident with ~470 mMD, located deeper than the flash point region in well MO-2 (Fig. 8). It is believed that physical and chemical conditions requisite for the stress corrosion cracking phenomenon leading to the tubing failure were not initially encountered in well MO-2. In fact, a replacement capillary tubing (also of SS 316), which was run-in last October, 2000 is still in service at well MO-2. It was pulled out and recovered intact last April, 2001.

What is the environment in well SP-4D, where the tubing was immersed for a far longer time? The capillary tubing was in service in well SP-4D for about one whole year, a period of 8760 hours, in contrast to its 14 hours of service in well MO-2. During this time it was in a high temperature (240°C), high Cl (4400-4600 ppm) and moderate H_2S (~1 mmol/100mol H_2O) environment. During flashing, the fluid becomes supersaturated with calcite at $CSI \sim 4$. In this well, the tubing was set at 815 mMD just slightly above a confirmed calcite blockage at 825 mMD (Fig. 9). Theoretical calculations at that time suggest that the flash point of the well under choked conditions ranged from 435-800 mMD. However, the WHP and enthalpy of the well varied resulting in conditions of much lower flash point than the injection point or failure of inhibition during some periods of the operation. The location of the parted portion of the tubing inside well SP-4D would have been at ~585 mMD (Fig. 9). The parted portion of the tubing is within the flash point region of well SP-4D, a locus of vibrational stress. During those instances when the flash point was below the injection point, the failed inhibition caused the deposition of calcite or silica or both providing the crevices for the concentration of chloride on the tubing walls resulting to corrosion pitting.

Pits once formed can magnify stresses, and additional thermal stress on the tubing can promote stress corrosion cracking. With the tubing pull-out, additional thermal stress was also introduced. Subsequent spooling introduced other residual stress on the tubing. Moisture from clinging geothermal fluids was spooled with the tubing. Evidence for the presence of entrained geothermal fluids are the calcite and halite crystals found in the big cracks. During this pull-out, the capillary tubing was not yet subjected to freshwater washing and

wipe drying (See Buñing, 2000). The geothermal fluid which was pooled in the pits concentrated and could have initiated SCC upon entry of O₂ during storage.

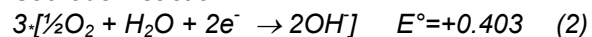
The reservoir fluids of well SP-4D are similarly close to neutral at pH=6.6, Cl_{res} = 4400-4600 ppm, Ca_{res} = 70-80 ppm, Mg_{res} = 0.1 ppm, SO_{4res} = 36-40 ppm, and over-saturated with calcite at CSI ~ 4, T_{SiO₂} ~240°C, CO_{2TD} of 18 mmols/100 moles steam and H_{2S_{TD}} of ~1 mmol/100 moles H₂O. Neutral pH at 240°C is at 5.55, making the reservoir fluids of SP-4D slightly basic. Similar to MO-2, dissolved oxygen levels at 240°C is almost nil (Fig. 7), rendering oxidative corrosion impossible inside the wellbore.

The corrosion products hematite (Fe₂O₃) and magnetite (Fe₃O₄) found in the fractured tubing must have been formed under conditions of high oxygen levels occurring at much lower temperatures outside the well bore. This was likely encountered during the 3 months storage of the tubing in Mindanao. It is believed that the following electrochemical reactions occurred in the abraded or pitted stainless steel surface in the presence of water and oxygen:

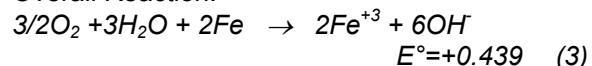
Anode Reaction:



Cathode Reaction:



Overall Reaction:



However 2Fe(OH)₃ can also exist in its hydrated form like Fe₂O₃·3H₂O or hematite. This product can only exist in a highly oxidizing environment as the oxidation of Fe into Fe⁺³ requires a strong oxidizing agent like O₂ to take place.

Similar to MO-2, the high temperature environment in SP-4D precludes the presence of oxygen. Where and when was oxygen introduced to the tubing environment? Atmospheric oxygen was introduced in two instances: 1) inside the tubing during injection of river water diluted inhibitor, and 2) during pull-out and subsequent storage from May to September, 2000. Petrographic analysis shows the presence of O₂ rich corrosion products of

hematite and magnetite. Previous studies (Soylemezoglu and Harper, 1982) have shown that this products gain dominance in high O₂ environments, a condition not present in the geothermal well. By inference, this condition was encountered outside the geothermal well under atmospheric contamination.

Microscopic investigation shows that branching cracks were propagating from outside, rather than from the inside. In some cases, the cracking is so severe that it has breached the tubing wall. In most cases, pits developed into cracks. However, there are also some pits that do not have cracks. This is indicative that the outside environment was responsible for the SCC, rather than the inside fluid environment. Fine hairline cracks propagating from inside were also seen in some thin sections (Fig. 6). This suggests, that similar to the outside, the inside must also be protected from moisture and oxygen during storage. Perhaps, the inside has a slower rate of SCC due to the absence of corrosive Cl and H₂S species.

3.0 DISCUSSIONS

It is generally accepted that stress corrosion cracking of austenitic stainless steels in geothermal environments requires a unique set of parameters to be encountered (Lichti et al., 1995). These conditions include:

- a) Concentration of corrosive species, eg. Chlorides, sulfur – any one is sufficient
- b) Moisture or wetness – thin films of moisture is sufficient
- c) Tensile stress – residual stress is sufficient
- d) Temperature in the range 60 to 180°C – failures have been observed at temperatures as low as 30°C for some alloys
- e) Oxygen (at high chloride environment very little oxygen is require)
- f) Material susceptibility – typically austenitic structure and less than 42% Nickel

In this case the cracking was preceded by localised pitting corrosion. The corrosion pitting left a roughened surface but showed no

evidence of intergranular attack. This would indicate that the level of acidity was not high. Significant Cl was found in the corrosion pits suggestive that the local corrosive environment leading to pitting was rich in chloride rather than sulfide.

The service history, analytical results together with known mechanisms of pitting corrosion and SCC suggest the following possible sequence of events leading to final failure of the capillary tubing.

- a) The tubing was placed in well SP-4D for a period of one year and in that time the level of the flash zone varied and crossed the area of final failure.
- b) Periods of failed inhibition (when the flash point was below the injection point) in SP-4D caused the deposition of calcite or silica or both in the tubing sufficient to provide crevice areas for the concentration of chloride ions next to the surface of tubing where corrosion pitting occurred.
- c) Normally oxygen and some chloride concentration mechanism is required for SCC to occur. In high temperature geothermal environments O_2 is low but there have been reported incidence of SCC in non-aerated geothermal environments with 140,000 ppm Cl (De Berry et al., 1978). The tubing did not fail while in well SP-4D, and when it was removed and subsequently run into well MO-2. This suggests that either the cracking environment was not sustained for the period of exposure in well SP-4D.
- d) Further cracking may have occurred in well MO-2. In this case, the argument would be that air and oxidized sulfur species formed in the corrosion products upon removal of the tubing from SP-4D were carried with the tubing in well MO-2. However, the tubing did not fail inside the well and it could be argued that the time of exposure was short and the cracking did not progress to final failure or the environment changed perhaps by depletion of available oxygen and the cracking stopped.
- e) Final failure on removal of the tubing from well MO-2 occurred as a result of plastic deformation as the tube was bent initially

over the top pulley and reverse bent near the bottom pulley. The first failure was probably at the bottom pulley with the tubing being unable to rapidly feed through the packing and again breaking near the top pulley as the sinker bar dropped inside the well.

4.0 CONCLUSIONS

The injection tubing of the calcite inhibition system composed of ASTM 316L capillary tubing was subjected to SCC. The cracking is preceded by localized pitting corrosion. The local corrosive environment leading to cracking is rich in chloride. The presence of chloride was evidenced from petrographic identification of halite and EDAX analysis of the as received corrosion products. Sulfur compounds are also present and there may be contribution from sulfide to the SCC. The presence of chloride, sulfur and other elements (Ca, Al, Si, K) suggest that the pitting and cracking took place in contact with geothermal fluids.

The results of the investigation do not clearly define the time of cracking. However, there is strong evidence to suggest that the pitting occurred in the chloride rich environment of well SP-4D. This was induced by a moving area of flash zone which crossed the zone of final failure. Periods of failed inhibition (when the flash point was below the injection point) in SP-4D caused the deposition of calcite or silica or both in the tubing sufficient to provide crevice areas for the concentration of chloride ions next to the surface of tubing where corrosion pitting occurred.

Three mechanisms for the SCC are proposed:

- a) The SCC could have occurred in well SP-4D in a chloride rich non-aerated environment, or
- b) In well MO-2, at portions of tubing with trapped air (from atmospheric storage) found in calcite scales and corrosion products from a previous SP-4D usage.
- c) Entrained geothermal fluids clinging to the outside tubing and in calcite or silica scale crevices (and in the pits?) promoted stress corrosion cracking and oxidative corrosion during pull-out and storage.

SCC of austenitic stainless steels like 316L is not considered a problem in high temperature non-aerated geothermal environments like MO-2 and SP-4D. Normally, some oxygen and a chloride concentration mechanism is required to obtain chloride SCC. If we strictly follow these arguments, only pitting corrosion is expected in well SP-4D due to lack of oxygen in the high temperature environment. However, two avoidable conditions promoted pitting in SP-4D. These include: 1) failure of inhibition resulting to concentration of calcite, silica and Cl in the tubing close to the flash point, and 2) the pull-out and storage of the wet tubing specifically at portions where there are already deposits and pitting provided the entry of oxygen into the system. Evaporative concentrations of geothermal brine during storage of tubing cannot be discounted as a possible mechanism for chloride concentration. Additional stresses were also introduced by spooling and the hot/cold conditions of numerous run-in and pull-out. These abnormal conditions can be avoided and controlled to prevent future failures.

5.0 RECOMMENDATIONS

To prevent failures of capillary tubings in service to calcite inhibition set-ups the following recommendations are forwarded:

- a) Revise the calcite inhibition system (CIS) capillary tubing manual to include SOP's on pull-out and storage. The outer tubing should be washed with freshwater to remove adhering corrosive geothermal contaminants, wiped dry and greased. The inner tube should be cleaned with water followed by N₂ purging to prevent atmospheric corrosion during pull out and storage.
- b) Thermal and spooling stresses can be avoided by a single run-in, with pull-out only for emergency cases and/or replacement every about 3 years.

- c) Ensure that injection tubing is always below the water level to avoid conditions that cause pitting and SCC to develop on the surface.

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