After two years and nine months of service, corrosion was found on the internal surfaces of premium connection tubing with couplings of 2 7/8-in (73-mm) by 6.4-lb/ft P110 tubing. The well depth range of corrosion was 1,312 to 4,921 ft (40 to 1,500 m) with temperatures of 183 to 212°F (84 to 100°C). The premium connection tubing, from 2,428 to 4,265 ft (740 to 1,300 m) in depth with a temperature of 192 to 205°F (89 to 96°C), was severely corroded. The field pin ends of the tubing were more severely corroded than the mill pin ends, and some of the field pin ends with severe corrosion products were washed out.

The output oil is 178 ton/d, and carbon dioxide (CO₂) content is 0.69%. The temperature is 284°F (140°C) at the bottom, and 167°F (75°C) at the well head. The pressure is 8,122 psi (56 MPa) at the bottom, and 4,351 psi (30 MPa) at the wellhead. The tubing string is 16,732 ft (5,100 m) long.

Corrosion Analysis

Macro-Corrosion Morphology Analysis

Figure 1 shows the corrosion morphology on the internal surface of the tubing. Corrosion was limited to the internal surface throughout the length of the coupling, and featured axial groove morphology. The corrosion became increasingly severe from the mill coupling end to the subsidiary torque shoulder of the field end. There was corrosion perforation at the field pin end, and the corrosion from the field pin end to 28 mm away was most severe. The remaining wall thickness at the field pin end was only ~0.4 mm; the remaining wall thickness at the mill pin end was 1.5 to 2.2 mm. The morphology showed erosion-corrosion (Figures 1 and 2). There was also corrosion on the internal surface of the...
tubing body, but it revealed no erosion-corrosion features, and corrosion was much less than that at the connections.

**Micro-Corrosion Morphology Analysis**

Scanning electron microscopy of the corrosion perforation and pits on the internal surface of the tubing revealed corroded penetration (Figure 3), CO$_2$ corrosion (Figures 4 and 5), and belt erosion-corrosion (Figure 6) morphology. The corrosion product contained C, O, Na, Al, Si, S, Cl, Ca, Mn, and Fe.

Micro-corrosion morphology and corrosion product analysis revealed that corrosion products were carbonate and chloride, indicating CO$_2$ and erosion-corrosion. These data show that the tubing failure was caused by both erosion-corrosion and CO$_2$ corrosion.

**Material Test and Analysis of Tubing**

The test results indicated that the tubing material met API 5CT, and that the tubing experienced erosion-corrosion and CO$_2$ corrosion. Erosion-corrosion is the combined effect of fluid (or fluid and corrosive medium) and erosive particles in the tubing. The fluid and hard impurity particles together form the mechanism of erosion-corrosion, and are continuously impinging and ploughing the metal surface and removing metal flakes in some local regions. Erosion-corrosion is primarily affected by the strike angle and shape of the particles. The extent of damage and distribution depends on the geometrical shape of the tubing. In parts subject to abrupt geometric change, erosion-corrosion is very severe because the parts are exposed to violent fluid turbulence and abrasive particle concentration. The presence of a corrosive medium causes corrosion on metal surfaces. Once the corrosion product is removed by fluid and impurities, the bare metal is
exposed to corrosion. The severity of the corrosion increases as the corrosion product removal process continues.

**Discussion**

After less than three years of service, tubing corrosion perforations occurred. The cause of corrosion is related to the premium connection configuration and the corrosiveness of the fluid.

**Premium Connection Configuration**

The most severe corrosion area was limited to the internal surface near the field pin end. This corrosion is related to the premium connection configuration. Although the premium connection is a flush bore, there is a V form notch at the subsidiary torque shoulder that is subject to abrupt geometric change (Figure 7). Turbulence occurs at the V form notch as liquid flows through the premium connection; erosion-corrosion takes place because of the shear stress stemming from the geometric changes in the connection. At the same time, corrosion occurred on the internal surface of the tubing because of CO$_2$ and Cl$^-$ in the oil. Erosion accelerated corrosion because low-density corrosion products could be easily washed out. The configuration of the premium connection is the same at the field and mill ends. Corrosion at the field end is more severe than that at the mill end because of different make up torque between the two ends. The pin bore of the connection is reduced because of interference between the pin and box. If make up torque is too large at the field end, erosion-corrosion will increase because the geometric change increases. If make up torque is insufficient at the field end, the shoulders of the pin and box do not come in contact; this forms an aperture subject to abrupt geometric change between the pin shoulder and box shoulder. More severe liquid turbulence and shear stress will occur,
which leads finally to more severe erosion-corrosion. Beside the V form notch at the subsidiary shoulder, there is a geometric shape change between the pin and coupling on the internal surface of the premium connection; the pin inner diameter is smaller than that of the coupling, and that can cause liquid turbulence.

The severe corrosion range on the internal surface of the tubing was limited to the coupling length, from mill coupling end to field coupling end. The distribution of corrosion on the internal surface may be related to the pin bore reduction and stress change after make up. As the joints are made up, the coupling swells and reduces the pin bore; this causes micro-structure and stress changes on the internal surface of the section, which permits corrosion to take place as the liquid flows through the tubing bore.

Conclusions and Recommendations

- The tubing failure was caused by erosion-corrosion and CO₂.
- The cause of the premium connection corrosion was the V form notch at the subsidiary shoulder, causing an abrupt geometric change. This notch led to fluid turbulence and erosion-corrosion. Also contributing to corrosion were the CO₂ and Cl⁻ in the fluid.
- The use of properly constructed premium connection tubing is recommended.

References


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