Cause Analysis of Collapse and Tripping of HP2-13Cr110 Tubing in Well KeS2-2-12

Jijun Xue and Zhaobin Fan

ABSTRACT

The accident of the collapsed and tripped tubing in a high temperature and high pressure gas well during the oil recovery process was investigated. The macroscopic morphology of the collapsed tubing was analyzed, the physical and chemical properties of the collapsed tubing were tested, the collapsed tubing was detected by the magnetic particle flaw detection, and the physical collapse experiment of the used tubing were simulated with the same batch of new tubing. The results show that the physical and chemical properties of the material of the collapsed tubing meet the requirements of the factory standard and API 5CT standard. The main reason for the collapse and failure is that the sand from the formation causes the tubing passage to be blocked, causes the pressure difference between the inside and the outside of the tubing to exceed the collapsing strength of the tubing, results in collapsing and tripping the tubing. In addition, the SCC crack on the outer wall and the corrosion of the inner wall of the tubing have a non-negligible effect on the collapsing and tripping of the tubing.1

INTRODUCTION

A well KeS2-2-12, a high temperature and high pressure gas well, was put into operation on July 28, 2013. Before production, the tubing pressure was 93.52MPa and the A annular pressure was 29.43MPa in this well. Produced with the nozzle opening of 8 mm+37%, and the tubing pressure was 86.92MPa. In January 2014, the tubing pressure and capacity started to decline abnormally. In April 2014, under the working system with a nozzle opening of 7.0mm, the tubing pressure fluctuated and

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decreased greatly, from the initial 79MPa to 21MPa. From 18:06 to 18:18 on June 16, the tubing pressure decreased from 82.95MPa to 0.97MPa, and the A annular pressure was about 35.6MPa. Around June 18, the pressure of the tubing and the casing tends to be consistent, and the tubing and the casing were channeled, indicating that the tubing had been collapsed and tripped. After shutting down the well on June 22, the tubing pressure increased from 26.57MPa to 82.53MPa, the A annular pressure increased from 27.88MPa to 42.25MPa, and the B, C, and D annular pressures were 0MPa. At 10:20 on June 27, the well was produced. At 14:35, the tubing pressure dropped from 82.53MPa to 12.16MPa, the A annular pressure dropped to 0.72MPa, and the instantaneous output dropped to zero. On June 28, the well was operated to measure flow temperature, pressure and sand surface, and the resistance was encountered when the test tools were strung down to 6127m. On August 17, 2017, the tubing string was began to lifting, the No. 627 (out of the well number) tubing, Ф88.90mm×6.45mm HP2-13Cr110 BEAR tubing of JFE, was tripped at the factory end, and the depth of the tripped tubing was 6180m. The 627# tubing retrieved from the work over has been collapsed.

In this paper, in order to analyze the tripping and collapsing causes of the tubing, the tripped coupling and the tubing were sampled, their physical and chemical properties were tested, and their failure behavior was analyzed and discussed.

MACROSCOPIC MORPHOLOGY AND PHYSICOCHMICAL ANALYSIS

The macroscopic morphology of the 627# collapsed tubing and the tripped coupling was analyzed. The results are shown in Fig. 1. It can be seen from Fig. 1(a) that the tubing has been collapsed and some sections have serious bending deformation. Fig. 1(b) clearly shows that there are obvious scale layers on the outer wall of the collapsed tubing. The scale layers are gray-white and partially break off, and the tubing in the falling place has obvious corrosion[1]. There is a 42cm long longitudinal crack and a 5.4cm long transverse crack at 108cm-150cm from the end face. The crack may be generated during the salvage process[2-4]. Fig. 1(c) shows the macroscopic morphology of the tripped coupling of the 627# tubing (dividing the coupling ends into 0°, 90°, 180° and 270°). It can be seen that the coupling has undergone severe deformation, in which 90° and 270° internal threads are significantly plastically deformed, and no obvious scratches or deformations are observed at 0° and 180°. The 90° and 270° deformations were treated with plastic film and the wear diameters were measured to be 28mm and 19mm respectively.

Fig.2 shows a cross-sectional photograph of the 627# collapsed tubing and the macroscopic morphology of the inner wall of the tubing. It can be seen from Fig.2(a) that the cross-sectional shape is a 8 character figure shape, and there is a soil plug in the tube. Then the lug is analyzed by XRD. The results show that the plug components are NaFe (PO4), CaCO3, SiO2, Fe2SiO4, KClO3 and MgK(PO4) (H2O), mainly phosphate, carbonate and sand.
Fig. 2(b) shows that there is obvious and intensive pitting in the inner wall of the tubing. Through analysis we can see that the tubing pressure and the casing pressure tend to be the same around June 18, 2014, which indicates that the tubing and the casing had been channeled, the tubing had been collapsed and tripped, A annular completion fluid was immersed in the tubing, and the tubing was in the completion fluid +CO2+Cl-(formation water) environment[5]. The completion fluid used in the well is 1.40g/cm3 OS-200, which is similar to Weigh4 completion fluid. Its composition is mainly pyrophosphate and chromate, which is alkaline[6]. Therefore, the corrosion of Super 13Cr martensitic stainless steel in OS-200 completion fluid can be analyzed based on the previous study of Weigh4 completion fluid.

Fig.3 shows the uniform corrosion rate of super 13Cr martensitic stainless steel in different temperatures at 180°C. From the diagram, the corrosion resistance of super 13Cr martensitic stainless steel in Weigh4 completion fluid is poor. The uniform corrosion and local corrosion in the formation water and CO2 environment at 180°C are relatively slight, and the uniform corrosion rate is 0.0375 mm/a. The corrosion in Weigh4 completion fluid at 180°C is more serious than that in the formation water. The uniform corrosion rate is 0.1419mm/a, and obvious local corrosion occurs on the surface of the sample. If the tubing and the casing are channeled, then CO2 invades into the A annular between the tubing and the casing,
the uniform corrosion rate of the super 13Cr increases to 0.3867mm/a, and the local corrosion is more serious than the CO2-free environment. Therefore, serious pitting corrosion occurred on the inner wall of the tubing in the completion fluid +CO2+Cl-(formation water) environment.

The chemical composition analysis of the 627# collapsed tubing is carried out. The results are shown in Table I. It can be seen from the data in the table that the chemical composition of the tubing meets the requirements of JFE.

The mechanical properties of the 627# collapsed tubing are tested. The results are shown in Table II. It can be seen that the mechanical properties of the collapsed tubing meet the factory standard, which shows that the collapsed tubing is not caused by quality problems. In order to find out the problem, the magnetic particle flaw detection is carried out on the outer wall of the tubing sampled from the well KeS2-2-12.
MAGNETIC PARTICLE FLAW DETECTION AND ANALYSIS

The magnetic particle flaw detection is performed on the outer wall of the pipe segment, and the results are shown in Fig. 4. It can be seen from the Fig 4 that there are longitudinal cracks at different positions on the outer wall of the tubing. This may be due to the maximum pressure difference between the tubing pressure and the casing pressure at wellhead is 78.01MPa (the tubing pressure is greater than the casing pressure) before the tubing and the casing were channeled. Because of the large circumferential stress on the outer wall of the tubing, the longitudinal SCC cracks have been initiated and propagated under the synergistic action of corrosion.

PHYSICAL COLLAPSE EXPERIMENT

In order to understand the influence of the tubing anti-collapsing strength by cracks on the outer wall and pitting corrosion on the inner wall of the tubing, the physical collapse experiment is used to analyze and verify the results in this study. The 1.5m length samples of the 626# tubing (cracked) and the same type of new tubing are used to collapse test according to the standard ISO 13679:2002. The test conditions and results are shown in Table III. According to the data in the table, under the same test environment, the collapse resistance of 626# tubing with cracks is 10MPa lower than that of the new tubing. It can be seen that when the tubing is corroded and its surface crack initiation is caused by stress, the risk of collapsing of the tubing will be increased[7].

<table>
<thead>
<tr>
<th>TABLE I. CHEMICAL COMPOSITION OF 627# TUBING.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Element</td>
</tr>
<tr>
<td>-----------------</td>
</tr>
<tr>
<td>Content</td>
</tr>
<tr>
<td>JFE requirements</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>TABLE II. MECHANICAL PROPERTIES OF 627# TUBING.</th>
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</thead>
<tbody>
<tr>
<td>Tensile test (room temperature)</td>
</tr>
<tr>
<td>Items</td>
</tr>
<tr>
<td>-----------------</td>
</tr>
<tr>
<td>Test results</td>
</tr>
<tr>
<td>Factory standard</td>
</tr>
<tr>
<td>JFE requirements</td>
</tr>
</tbody>
</table>
Figure 4. Magnetic particle flaw detection of the outer wall of 627# tubing.

### TABLE III. CONDITIONS AND RESULTS OF THE EXPERIMENT.

<table>
<thead>
<tr>
<th></th>
<th>626# tubing</th>
<th>New tubing</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Steel grade</strong></td>
<td>HP2-13Cr110</td>
<td>HP2-13Cr110</td>
</tr>
<tr>
<td><strong>Dimension</strong></td>
<td>Φ88.90mm×6.45mm</td>
<td>Φ88.90mm×6.45mm</td>
</tr>
<tr>
<td><strong>Test temperature</strong></td>
<td>Room temperature</td>
<td>Room temperature</td>
</tr>
<tr>
<td><strong>Test medium</strong></td>
<td>City water</td>
<td>City water</td>
</tr>
<tr>
<td><strong>Collapse failure pressure</strong></td>
<td>108MPa</td>
<td>118MPa</td>
</tr>
</tbody>
</table>

### CAUSE ANALYSIS OF COLLAPSING AND TRIPPING

Since the well KeS2-2-12 was put into operation on July 28, 2013, sand production began at the bottom of the well during the subsequent production, resulting in decreased production capacity, decreased tubing pressure, decreased flow rate and decreased sand carrying capacity. The sand discharged from the wellhead was getting less and less, and the accumulation of sand in the wellbore was getting more and more serious. The tubing passage was blocked due to sand production from the formation. According to the preliminary research data: on June 16, 2014, from 18:06 to 18:18, the tubing pressure dropped from 82.95MPa to 0.97MPa, at 23:36 (about 5 hours), and the tubing pressure was less than 1MPa. At 13:48 on June 17, 2014, the tubing pressure was always lower than the casing pressure, and then the tubing pressure and the casing pressure fluctuated and finally became consistent. It means that the tubing and the casing had been channeled at the time.

The collapse experiment of 88.9mm×6.45mm HP2-13Cr110 BEAR tubing shows that the collapse strength of the cracked tubing is about 108MPa.

The depth h of the coupling of 627# tubing is about 6180m, and the density ρ of the annular completion fluid is 1.40g/cm³. From the formula 1, the liquid column pressure PL is about 85MPa.
$$P_L = \frac{\rho gh}{1000}$$  \hspace{1cm} (1)

Among them: $P_L$ is liquid column pressure, MPa; $\rho$ is the density of annular protection fluid, g/cm$^3$; $h$ is the height of the liquid column in the well, m.

The pressure difference between the internal and external of the tubing is shown in formula 2.

$$\triangle P = P_L + P_A - P_O$$  \hspace{1cm} (2)

Among them: $\triangle P$ is the pressure difference between the internal and external of the tubing, MPa; $P_L$ is the pressure of the liquid column, MPa; $P_A$ is the A annular pressure, MPa; $P_O$ is the tubing pressure, MPa.

Calculate the pressure difference between the internal and external of the tubing at 18:06, 18:12 and 18:18 on June 16, 2014, respectively, as shown below,

1) At 18:06 on June 16, 2014, the tubing pressure was 82.95MPa, and the A annular pressure was 35.78MPa. At this time, the pressure difference between the internal and external of the tubing was:

$$\triangle P = 85\text{MPa} + 35.78\text{MPa} - 82.95\text{MPa} = 37.83\text{MPa}$$

2) At 18:12 on June 16, 2014, the tubing pressure was 59.57MPa, and the A annular pressure was 35.71MPa. At this time, the pressure difference between the internal and external of the tubing was:

$$\triangle P = 85\text{MPa} + 35.71\text{MPa} - 59.57\text{MPa} = 61.21\text{MPa}$$

3) At 18:18 on June 16, 2014, the tubing pressure was 0.97MPa, and the A annular pressure was 35.30MPa. At this time, the pressure difference between the internal and external of the tubing was:

$$\triangle P = 85\text{MPa} + 35.30\text{MPa} - 0.97\text{MPa} = 119.33\text{MPa}$$

From the above calculation, it can be seen that at 18:06 and 18:12 on June 16, 2014, the pressure difference between internal and external of the tubing was less than 108MPa which was the collapsing strength of the tubing, and the tubing did not meet the collapsing condition. At 18:18 on June 16, 2014, the pressure difference between internal and external of the tubing exceeded 108MPa which was the collapsing strength of the tubing, the tubing was collapsed at the time.

**CONCLUSIONS**

1) Sand production from the formation results in blockage of tubing passage. From June 16 to 18, 2014, the external pressure of 627# 88.90mm×6.45mm HP2-13Cr110 tubing in 6180.85-6190.81m section was greater than the internal pressure, and the difference between the external pressure and the internal pressure of the tubing exceeded the tubing collapse strength, the tubing was collapsed and then tripped.
2) Under the action of circumferential stress, longitudinal SCC occurred on the outer wall of HP2-13Cr110 tubing. Due to SCC cracks on the outer wall and pitting corrosion on the inner wall of the tubing, the anti-collapse performance of the tubing was decreased, and the risk of tubing being collapsed was increased.

REFERENCES

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