

Failure on Heater Treater Tubes - Case Study

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ABSTRACT

Heater Treater tubes are designed for the removal of emulsifiers and unwanted salts from crude oil. This paper will discuss a case study completed on two heater treaters that exhibited premature failure after 8 months in service, involving an extensive fire with a subsequent loss of production.

Multiple cracking on the mitrated elbow welds, on the flanges to shell circumferential weld and a collapsed tube were observed in the heating section, after the treater went out of service. Visual inspection, metallurgical analysis, physicochemical analysis of the formation water, corrosion deposits analysis and stress analysis were completed to identify the root cause of the failure. Results indicated that the accumulation of deposits from the reservoir water and a low level of crude oil due to the reduction in production caused high thermal cyclic stresses on critical welded areas in addition to a localized overheating on the collapsed tube.

Key words: Heater Treater tubes, reservoir water deposits, asphaltene, mitrated elbows, cracking, premature failure.

INTRODUCTION

Heater Treater tubes are designed for the removal of emulsifiers and unwanted salts from crude oil. Their purpose is to facilitate the oil and water separation by breaking emulsions by means of increasing the temperature of the oil, reducing its density and viscosity. A heater treater is a 3-phase separator vessel, equipped with fire tubes, that utilizes heat and mechanical separation devices to facilitate the separation of oil-water emulsions¹. Its separate gas from the incoming emulsion and separate the

*Working with Petrocorr, C.A. when the work was conducted.

emulsion into a water phase and an oil phase. Heater treaters can be vertical or horizontal in design². The main difference between them is the residence time, which is shorter in the vertical configuration compared with the horizontal one.

Process Description^{1,2,3}: Fig. 1 shows a schematic drawing of a Horizontal Heat Treater³. It consists of four sections: 1. Inlet degassing section, 2. Heating section, 3. Differential oil control chamber and 4. Coalescing section.

Untreated crude enters the degassing section of the Heater Treater through the inlet top section. Free gas is liberated from the flow stream and is equalized across the entire degassing and heating areas of the Treater.

On the heating Section, the emulsion passes over the fire tubes while is heated, a free water and solids flow down into the free water section of the vessel while the emulsion rises to the coalescing section. On the tube side of the heating section, the combustion gases enter through the burner side tube (hot tube) and exit through the chimney side (cold Tube). The heat released gas which then joins to the free gas from the inlet section.

The heated oil and emulsion rise over the fire tubes and flow into an oil surge chamber containing a differential float device that regulates the oil level.

The oil and emulsion flow into the coalescing section through a spreader. This section comprises an electrostatic device that passes alternating current through the emulsion to induce droplet coalescence. As the water molecules separate from the emulsion, they collide and form larger droplets that settle to the bottom of the tank under the force of gravity. The dry oil is tapped via a separate outlet at the top of the tank.

The Heater Treater from this current study operates in the range of 71°C-77°C (160°F-170°F) at about 0.55 MPa (79 psig) with inlet temperature of about 32°C (90°F). Maximum designed tube skin temperature is 450°C (842°F)⁴.

This paper presents a case study of two Heater Treaters Tubes that experienced premature failures under a circumstance where a shortage of production of about 36% and standby for about two months was necessary.

BACKGROUND

Heat Treaters considered on this study were located on two different production fields and experienced diverse type of damage. For the purpose of this paper Heater Treaters would be named: HT1 and HT2.

Heater Treater HT1: The Heater Treater processes a 23-24 API crude and was working about its 36% of the design capacity at the time of the failure. Failure occurred after about 8 months in service causing an intense fire with moderate damage on nearby equipment and no personal injuries. Multiple cracks were reported on the weld of the mitred elbow by the time of the failure. It is believed that the cracking located in the mitred elbow led to the direct contact of the emulsion with the burners of the heater tubes causing the fire. Operating pressure and temperature were reported “normal” two hours before the failure. Water level was reported to be lower than the water “set point” and the sand-jet system (pressured water) used for deposits cleaning was reported not working.

Heater Treater HT2: Treater process a 29 API crude and was working about its 17% of the design capacity at the time of the failure. Failure occurred 6 months after being in standby mode for another two months. The cleaning deposits system (sand-jet system) was informed been working with a frequency of twice a day. The tube skin temperature reported by the thermocouple was variable, increasing with the time in service, from 350°C (662°F) (at the start), 383°C (721°F) (two months before the failure) up to

520°C (968°F) by the time of the failure. Additional high skin temperature pick, about 600°C (112°F), was captured before failure, by that time the burner was turned off and all the solids on the heater tubes were cleaned with the sand-jet system. By the time of the failure the outlet temperature was reported a slightly lower, 130°C (266°F), than the set point temperature, 150°C (302°F).

RESULTS

1. Visual Inspection

After the Failure, the Heater Treaters HT1 and HT2 went out of service and the two fire tubes from each heater, FT-1A y FT-1B, were removed for inspection and repair. For the purpose of the study the fire tubes were separated in four components (see Fig. 2): a) The lower tube where the combustion gases enter also known as “hot tube” located on the lower section of the vessel, b) the top tube where the combustion gases exit through the chimney also known as “cold tube” located on the upper section of the vessel c) mitred elbow, with U shape and multiple welds that join the lower section of the tube with the top tube section and d) Both flange to fire tube circumferential weld that joined the lower and the top tube with the vessel shell.

Visual Inspection revealed multiple through-wall cracking at the mitred elbow, cracking on the flange to fire tube circumferential welds (internal and external), misaligned flanges between the lower hot tube and top cold tube, an inward bulge in one of the fire heaters tubes and large amount of thick layer of deposits on the external surface of the lower hot tubes. Additionally, the sand-jet system (pressure water) used for deposits cleaning, located between the hot and cold fire tubes, were visually inspected and noticed that they were misaligned, pointing in a direction away from the tubes.

A summary table with the inspection findings and it corresponds schematic drawing for the HT1 are shown in Table 1 and Fig. 2, while a summary Table, for the HT2, with the inspection findings and it corresponds schematic drawing can be seen in Table 2 and Fig. 6.

Table 1 Summary of the Inspections Finding for the Heater Treater 1, HT1 and Fire Tubes FT1-A and FT1-B

Heat Treater 1: Tube FT-1A	Heat Treater 1: Tube FT-1B
Large amount of blackish, greyish, and whitish solids deposit on the external surface of the lower hot tube were observed. Tube surfaces were washed before inspected (Fig. 3a).	Large amount of blackish, grayish and whitish solids deposit on the external surface of the lower hot tube with a max thickness of 20 mm (Fig. 3b) was observed. Water jet system was detected pointing away the tube.
Two through-wall cracking on the mitred elbow (Fig. 4) that was believed to allow the ingress of the crude emulsion and cause the fire.	Cracking on the mitred elbow. Dye penetrant testing performed revealed that the cracking did no propagated to the internal surface of the tube.
Multiple cracking on the tube to flange circumferential weld (internal and external) on the hot fire tube and cold fire tube Flanges. (Fig. 5)	Multiple cracking on the tube to flange circumferential weld (internal and external) on the hot Fire Tube and cold Fire Tube Flanges
Misaligned between hot tube flange and cold tube flange	Misaligned between hot tube flange and cold tube flange
Inward Bulge on the hot fire tube (Fig. 3a) with reddish color on the internal surface in the area near the thermocouple indicating high temperature exposure at that particular location.	There were no bulges observed

Table 2 Summary of the Inspections Finding for the Heater Treater 2, HT2, and Fire Tubes FT1-A and FT1-B.

Heat Treater 2: Tube FT-1A	Heat Treater 2: Tube FT-1B
Large amount of blackish, greyish and whitish solids deposit on the external surface of the lower fire tube up to 25 mm of thickness. Water jet system was observed pointing away the lower tube (Fig. 7a)	Small and thinner amount of blackish, greyish and whitish solids deposit on the external surface of the lower fire tube up to 5 mm of thickness. Water jet system was observed to be pointing to the lower tube (Fig. 7b)
One through-wall cracking on the mitred elbow. Dye penetrant testing performed revealed that the cracking propagated to the internal surface of the tube (Fig.8)	Cracking was not observed in this tube
Misaligned between hot tube flange and cold tube flange	Misaligned between hot tube flange and cold tube flange

2. Metallurgical Testing

Chemical analysis and mechanical testing: Chemical analysis and tensile test were completed on representative samples of the heater tubes. Results indicated that the material of construction complies with the composition and mechanical properties for a carbon steel ASTM A 516 Gr-70⁵.

Metallographic examination and hardness testing of Bulge and non-affected based metal: Metallographic examination was completed on the base metal of fire tube FT-1A in order to compare the condition at the bulged location and the non-affected material. For the non-affected area, metallographic examination results indicated the typical microstructure of carbon steel, which consist of lamellae pearlite and ferrite (Fig. 9a). On the other hand, for the bulged area, some carbide platelets that have begun to spheroidize were observed (Fig. 9b), which is the typical microstructure of a carbon steel that have been exposed to a temperature of about 400°C (750°F) ⁶ at that particular location. As the tube metal temperature rose, the tube began to bulge when the yield point was reached while the wall thickness decreased.

Hardness readings (Vickers 20Kp) was completed at the bulge and the non-affected material. At the bulge area the hardness decreased from a value of 78 Hardness Rockwell B (HRB) for a non-affected tube to a 67 HRB for the bulged area.

Metallographic examination and hardness readings of the crack from the mitrated weld: Metallographic examination was completed on a cross-section at the crack tip located on the mitred elbow from the fire tube FT-1A. Metallographic examination results indicated the crack initiated on the external surface of the fire tube (OD) and propagated transgranularly toward the interior surface of the fire tube (ID) as can be seen in Fig. 10a and 10b. This propagation is characteristic of the mechanical stresses such as fatigue stresses, thermal stresses and tension. Crack initiated at the HAZ where a hard microstructure (martensite) and undercut were observed (Fig. 10c). The presence of a hard microstructure and notches and / or localized stresses can lead to the crack to initiate. This notch originated in the heat affected zone and is approximately 200 µm deep, not detectable by routine inspection methods.

Macro fractography examination was completed on an opened trough-wall crack surface, multiple ratchet marks characteristic of fatigue was identified⁷. Crack surface was damaged, cover by oxides.

Hardness readings (Vickers 20Kp) was completed at the base metal, HAZ and weld metal. The hardness profile at the base metal, HAZ and weld metal showed a bell behavior, with higher average hardness values in the heat affected zone of about 232 HV and lower average values in the base metal of about 196 HV Average. Hardness for the weld was around 203 HV.

Metallographic examination and hardness readings of the crack from the Tube to Flange Circumferential weld: Metallographic examination was completed on a cross-section at the crack tip of the Tube to Flange Circumferential weld from the fire tube FT-1A (cold and hot tube). In these photomicrographs (Fig. 11 a, b and c) it can be observed that the crack initiated at the HAZ of the flange to circumferential weld for both external and internal faces. Cracks initiated where geometric changes occurred and propagated with a stepwise morphology, most likely due to a cyclic stress. Lack of penetration can also be observed in the center of the fillet weld acting as notch for crack to initiate and propagate.

Hardness readings (Vickers 20Kp) was completed at the base metal, HAZ and weld metal. Hardness values range from 183 HV in base metal to 286 HV in weld.

3. Physicochemical Analysis of The Formation Water

Table 3 shows the typical results of the physical-chemical analysis performed on water samples taken on each production fields dispatch stations where each heat treater was located. It can be seen that the formation water has a high concentration of calcium and magnesium, indicating a tendency to form scale mainly at high temperatures.

Table 3 Physicochemical Analysis of Water Samples taken from Production Field 1 and 2.

Analysis	Production Field 1	Production Field 2
Carbonates (ppm de CO_3^{2-})	0	0
Bicarbonates (ppm de HCO_3^-)	1342	2172
Chlorides (ppm de Cl^-)	10666	10167
Sodium (ppm de Na^{+1})	7353	7239
Total Hardness (ppm de CaCO_3)	390	390
Calcium Hardness (ppm de Ca^{+2})	120	144
Magnesium Hardness (ppm de Mg^{+2})	22	7
Sulfates (ppm de SO_4^{2-})	165	5
Total iron (ppm de Fe)	1.65	0.5
pH	7.29	7.63

4. Chemical Analysis of Deposits

Energy Dispersive X-ray Spectroscopy (EDS), Scanning Electron Microscopy, and X-ray Diffraction analysis were performed on solids blackish deposits samples taken from Heater Treater HT1 with the following content results:

- High NaCl content.
- Calcium carbonate, CaCO_3 .
- Coke – Asphaltenes
- Iron and Silicon

Additional analysis was completed on the blackish hard and wet deposits taken from Heater Treater HT1 and HT2, respectively. Table 4 compares the results obtained from the gravimetric analysis. In

the extraction method used, the percentage of organic extract, the content of scales and inorganic components, insoluble in HCl (called sand) are obtained. The content of scales includes: bicarbonates, carbonates and salts soluble in acid medium.

Table 4 Gravimetric Analysis Results of the Deposits Samples from the Heater Treaters 1 and 2

Analysis	HT1 Blackish Hard Deposits (wt.%)	HT2 Blackish Wet Deposits (wt.%)
Moisture and Volatile	1.2	2.2
Organics	6.6	23.6
Sand (Insoluble in HCl)	13.1	3.1
Scales	79.1	71.1

It can be seen that both samples present scales as a primary component. Qualitative analysis of the scales (reactivity to HCl) indicates that they have large amounts of carbonates and, in the case of Heater Treater 1, also sulfides. The primary difference lies in the higher concentration of organic components in the Heater Treater 2 sample, at the expense of a lower “sand” content.

The results of the quantitative analysis of Ca, Mg and Si carried out in the inorganic components (scale + sand) are shown in Table 5. It can be observed that the Si compounds are the majority component in the extracts called “sand”, and the carbonates, Ca and Mg, are the majority component in the so-called “scales”. However, in the deposits of the Heater Treater HT1, significant amounts of components other than carbonate were present, which according to previous analyzes may be sodium chloride and corrosion products.

Table 5 Elemental Analysis Results of the Deposits Samples from the Heater Treaters 1 and 2

Analysis	HT1 Deposits	HT2 Deposits
Calcium	11.9%	28.1%
Magnesium	4385 ppm	10900 ppm
Silicon	10792 ppm	1294 ppm

5. Stress Analysis

Stress Analyses were completed to understand the effect of the temperature profile, the load, the deposits and out of service condition in the fire tubes and Flange. The assumptions made for the temperature distribution were based on information and field observation. These temperature distributions are not intended to be completely accurate. Table 6 shows a detail of the stress analysis cases and assumptions used for the stress analysis.

Stress analysis results indicated that the greatest contribution to stress came from thermal expansions. The contribution to the stresses due to sustained loads (weight and pressure) were substantially lower.

For all the cases studied under operating conditions, the maximum stresses occurred in the inner radius of the mitred elbow in the areas adjacent to the junction between the horizontal straight tube (upper and lower section) and the adjacent section of the mitred elbow. These high stress areas coincided with the welds heat affected zones and where cracks occurred.