Defining the optimal life management strategy for gas heater tubes

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1. Introduction

Industrial furnaces are used extensively throughout the entire oil and gas and other types of industry like pulp and paper, extraction of metals, chemical and petrochemical plants. An industrial furnace or direct fired heater is an equipment to provide heat for a process or can serve as reactor which provides heats of reaction. Furnace designs vary as to its function, heating duty, type of fuel and method of introducing combustion air. However, most process furnaces have some common features. Fuel flows into the burner and is burnt with air provided from an air blower, the flames heat up the tubes, which in turn heat the fluid inside in the first part of the furnace known as radiant section, where the fluid get the desire process temperature. After that, the flue gas (gases from combustion) leaves the radiant section to get into the convection zone, where the heat is recovered before venting to the atmosphere. Figure 1 shows a typical gas heater.

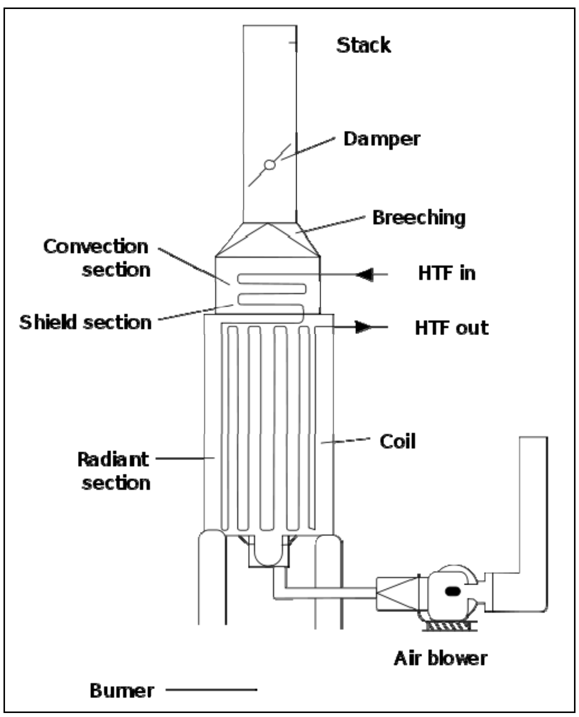

Figure 1.Typical gas heater layout

Due to the world financial crisis, exists and strong pressure over plant managers and engineers to explore ways to reduce operating costs. In case of gas heaters, operating cost is composed by energy (fuel gas consumption) and maintenance cost. For gas heaters the energy cost is a variable that most of time cannot be reduced or the effort to reduce it is not a cost-effective way, meaning that maintenance cost is the variable that can be managed by reliability engineers looking for an optimal maintenance inspection strategy.

There are some standards that help to develop a good maintenance inspection program for gas heaters, these are: API 530, API 573, ABSA-AB-507, API-581 (ed 2000 and API 579. However, if a risk based inspection program should be developed for gas a heater, API-581 (ed 2000) is limited due to furnace tube technical module is just for heating liquid process stream. Another important issue is that most furnace designers take the API 530 concept about defining the furnace tube life for 100.000 hours or 11.4 years. A simple question come up for maintenance managers and engineers, if my furnace tubes reach 100.000 operating hours, should I change all tubes? Can keep operating my furnace in this condition? .Replacing furnace tubes before the end of its useful life, can dramatically increase the operating cost, due to the cost of spare part and downtime. Replacing the furnace tubes after a tube failure could have very costly consequence and safety issues related. Is for those reasons a good maintenance inspection strategy should be developed for gas heaters, assuring the mechanical integrity, reliability and maximizing safety.

This article presents the way to define the optimal maintenance inspection strategy for the gas heater tubes. A case study for a gas heater is presented as an example of reliability and integrity analysis. Risk based strategy, visual inspection, replica metallographic and degradation analysis are tools used to perform the furnace tube remaining life assessment (RLA), helping to engineers, maintenance manager and plant manager to make the right decision even in an uncertainty environment.

2. Case study

The furnace tubes life management case study presented in this paper, focuses on regeneration gas heater type. However the process used to define the best maintenance strategy can be applied for any type of industrial furnace tubes. This heater is used for the gas regeneration process; the main function of the heater is to heat the gas that is getting out the dryers section. The heater type is vertical and cylindrical with tubes made in carbon steel fed with fuel gas working at 330°C. The following table shows some construction and operation characteristics. Figure 2 show the process applied to define the best maintenance strategy for regeneration has heater tubes.

Table-I Gas Heater data

Heater type	**Vertical and cylindrical**
Process	Gas regeneration
Maximum Allowable Working Pressure (tubes, Kg/cm2)	80
Maximum Operating Pressure (Kg/cm2)	68
Fuel	Gas
Maximum Design Temperature (°C)	350
Maximum Operating Temperature (°C)	331
Tube Material	A 106 Gr B
Schedule	80
Outside tube diameter (mm)	168.3
Design service time (years) per API 530	11.4
Current service time	11

2.1 Process for maintenance strategy selection

RBI “Risk Based Inspection” is the most known and pragmatic methodology for maintenance strategy selection for static equipment in Oil&Gas industry. However, in just few circumstances like presented in this article, standards are not very clear in terms of how to perform a risk based inspection program. Appendix-J from API 581 edition 2000 provide the guidelines to perform the likelihood analysis for furnace tube and just for furnace used to heat liquid process streams. In this particular case our gas regeneration heater uses gas to heat gas. In new API 581 2008 edition this module was removed. Because of the timing of furnace retubing can be critical in minimizing equipment costs and maintaining productivity and replacing heater tubes on an early stage can cost a huge amount of money, a procedure was designed to help to engineers to select and define the best maintenance strategy for this gas regeneration heater's tubes. This procedure uses information from standards API-581, API-530, API-573, API-560, API-571 and AB-507.

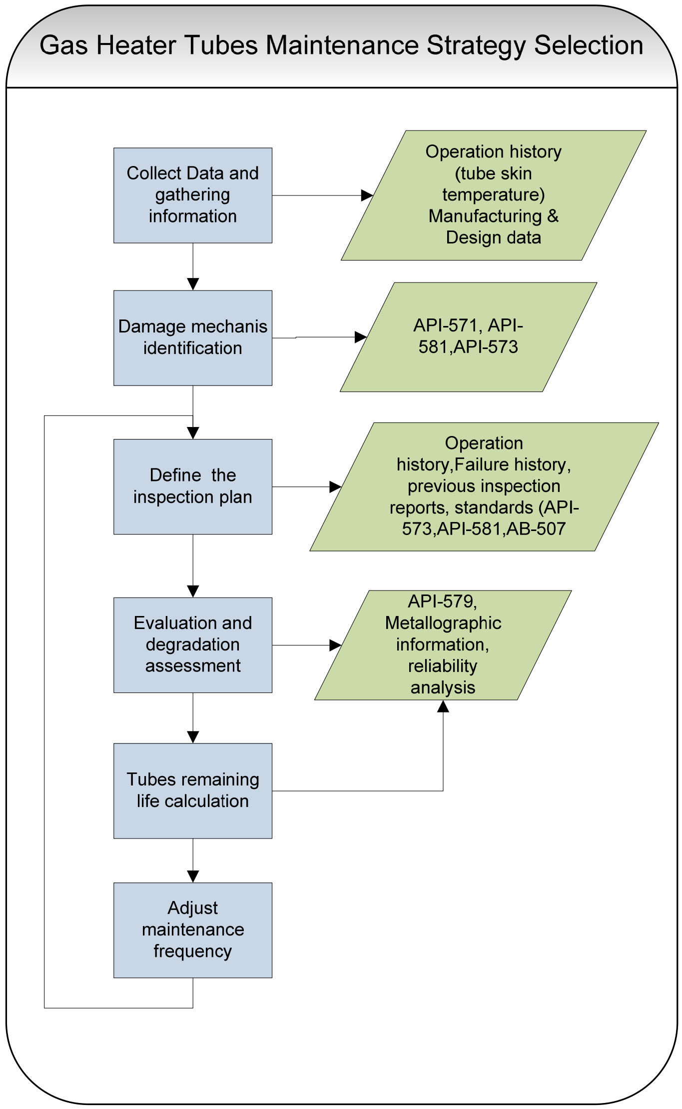

Figure 2. Gas heater maintenance strategy definition process

2.1.1 Collect data and gathering information

Operation, manufacturing and inspection data collection is crucial for tube's life maintenance strategy decision. Data on how the previous operating history has impacted tube life, predictions of deterioration rate, how the future operation will impact tube life, and finally, monitoring of operations and deterioration to ensure the analyses and predictions are required to understand how tube's life could be affected. Manufacturing data also is quite important to define the process operating boundaries, for example to establish the maximum operating tubes skin temperature. Data from previous visual, on-line and internal inspection is critical due to some issues can be advertised from this activities. Tubes should be inspected for bulges, sagging, bowing, localized discoloration or leakage. Hot spots may be the result of flame impingement. Tube misalignment may be caused by damaged supports, or supports that are preventing the thermal growth of the tube. Figure 3 shows the operation, inspection and online monitoring heater tubes condition, manufacturing data is shown in table I. From this figure it is clear that tubes from radian section are free from deformation, uneven heat, bowing and bulges. Information collected in this stage is crucial to define maintenance inspection frequency and strategy. Another important aspect is that heater tubes should always work within the maximum design temperature, like shown in this case study. If heater tubes have the chance to operate out of the temperature boundaries design, the tube's life could be reduced dramatically.

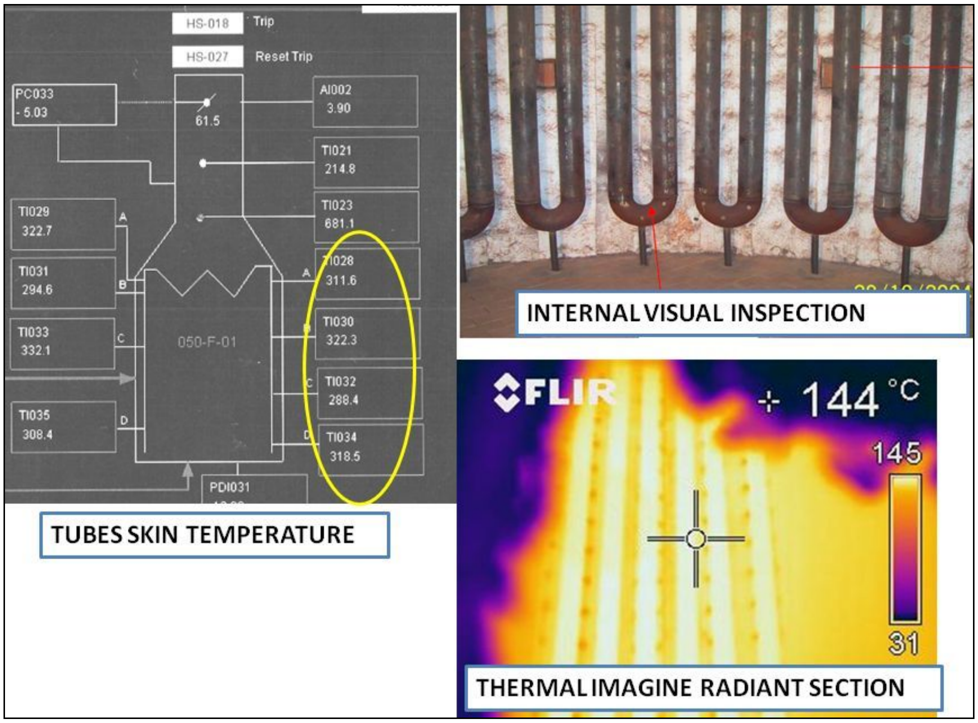

Figure 3. Process, internal visual and thermography inspection data collection

2.1.2 Damage mechanism identification and inspection plan

Damage mechanism identification stage is critical to define what best non-destructive and destructive technique will detect the expected damage mechanisms assessed. Heater tubes can experience deterioration both internally and externally, typical mechanism can be: creep, external oxidation, sulfidic corrosion, naphthenic acid corrosion, carburization, Hydrogen attack, metal dusting, spheroidization, erosion, internal corrosion and thermal fatigue. Susceptibility to one or more of this damage mechanism depends on tubes metallurgy, temperature operating conditions and type of process stream. For this case study, where process stream is fuel gas to heat gas that is a regeneration process where heating cycle exists, damage mechanism expected and inspection techniques are summary in the following table. In this section some standards like API-571, API-573 and API-581 can be useful to study the expected damage mechanisms.

Table-II Gas Heater damage mechanism

Damage Type	Damage mechanism	Inspection technique	Location and extension
Thickness reduction	• Internal corrosion • External corrosion	• Ultrasonic thickness measurement • Internal visual inspection	UT thickness measurement of all radiant tubes
Cracking	• Thermal fatigue	• Penetrant and/or Magnetic testing	Dye penetrant testing of 25% to 50% of weldments on radiant zone
Metallurgical changes	• Ferrite transformation • Spheroidization • Grain growth	• Metallographic replica	Spot metallographic analysis on radiant tubes

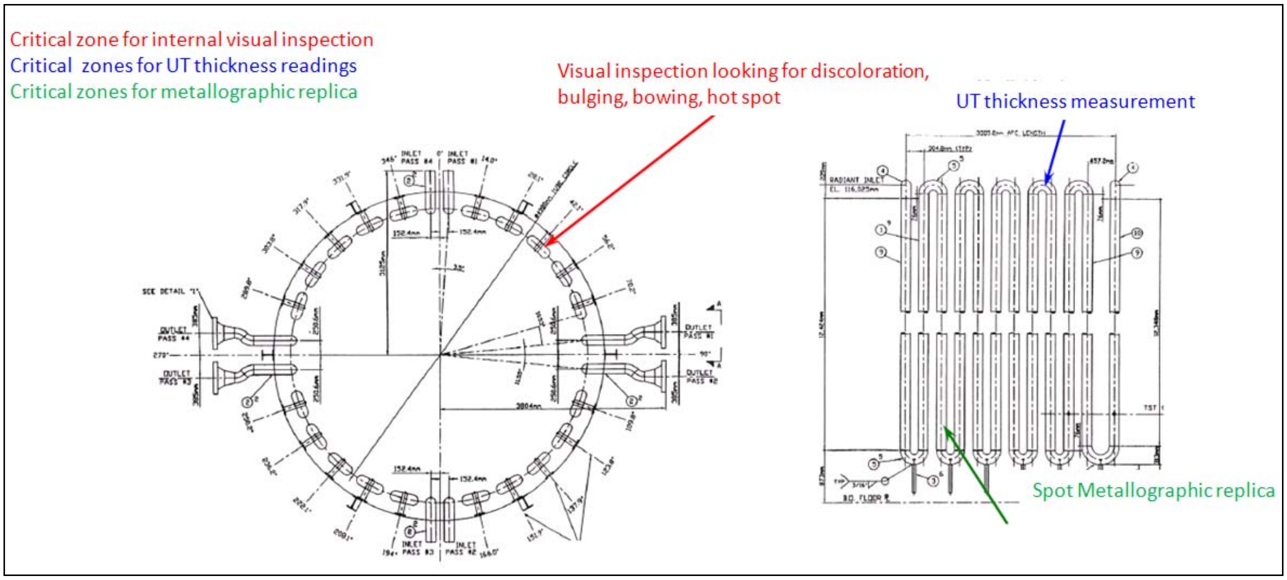

Figure 4. Detailed zones for heater tube internal inspection. Visual, UT and metallographic replica

Table-III Gas Heater inspection plan scope and frequency

Inspection type	Interval inspection (years)	Scope
• Visual internal	• 5	• Looking for hot spot, uneven heat, local corrosion, bulging, and bowing in all tubes. Visual inspection for internal and welded parts.
• UT thickness measurement	• 5	• Spot thickness measurement looking for thickness reduction. Scan B can be used if corrosion zone is detected
• Metallographic replicas and hardness measurement	• 5	• Spot metallographic replicas on radiant coil tubes near from tubeskin thermocouple zone

Internal tube corrosion: is predominantly influenced by the chemical composition of the process fluid, process and metal temperatures, fluid velocity and tube metallurgy. Type and rate corrosion on the internal surface of the heater tubes depend on the gas composition, some typical compounds that influence the type and rate of corrosion are H2S, CO2. For this particular case chromatography analysis shows that gas stream is quite clean and it has no aggressive compounds.

Table-IV Gas stream chromatography

Components	% Molar
N_2	0.905
CO_2	1.075
CH_4	88.765
C_2H_6	5.376
C_3H_8	2.165
i-C_4H_{10}	0.377
n-C_4H_{10}	0.669
i-C_5H_{12}	0.202
n-C_5H_{12}	0.194
C_6H_{14}	0.272

External tube corrosion: external corrosion of the tube depends on the heater atmosphere and temperatures. The external surface of the tube will corrode from oxidation, due to excess of oxygen necessary for combustion of the fuel at burners. Oxidation rates for a metal increase with increased temperature, is for this reason that tube skin control temperature is crucial for tube's reliability performance. Internal visual inspection is critical to detect sagging, bowing, bulging. For this particular case, due to the fuel gas is clean and free from sulfur compounds is that corrosion rate is quite low, furthermore visual inspection shown a good external aspect of tubes, without uneven heating and/or scaling.

Figure 4. Internal visual inspection of radiant coil tubes

Thermal fatigue: is the result of cyclic stresses caused by variations in temperature. Damage is in the form of cracking that may occur anywhere in a metallic component where relative movement or differential expansion is constrained, particularly under repeated thermal cycling. Cracks start at the surface of the material where the stresses are normally higher, progressing slowly at first and then more rapidly with each cycle of temperature change. Thermal fatigue is often found at locations where metals that have different coefficients of expansion are joined by welding. In this the regeneration gas heater works on duty cycles, heating by 16 hours and cooling down by others 8 hours, means that heater is exposed to two thermal cycles per day. If some tube expanding movement is constraint, cracks can be developed at seam welds. For that reason dye penetrant testing and/or magnetic testing is quite important to know the existence of cracks at welds. For this heater inspection no cracks have been detected.

Metallurgical changes: tubes subjected to high temperatures and stress for long periods can undergo metallurgical change. This change can results in various conditions, including carburization, decarburization, spheroidization and grain growth. Creep damage (time dependant deformation at high temperature of stressed components) in this case study is not a concern because of the maximum expected tube skin temperature is less than critical temperature for carbon steel (370-410°C). Even the creep damage mechanism it was not a concern for this heater, the tube´s service lifetime was determined by the design standard for heater tube thickness calculation (API 530) by 11.4 years. Metallographic replica and hardness measurement are the best ways to detect if there are metallurgical changes. For this case grain growth and spheroidization are the expected damage mechanism. In last tube's metallographic replica analysis shown that no carbide at grain boundaries was found, hardness level was less than 130HB (Brinell) and an average grain size of 6 based on standard measurements (ASTM E-112). Following pictures shown a ferrite matrix and an incipient perlitic globulization. Based on the chart in figure 5 where a perlite evolution exposed at high temperature is shown, it can be appreciated that the gas regeneration tube is in stage "B" (6-12% of life consumed).

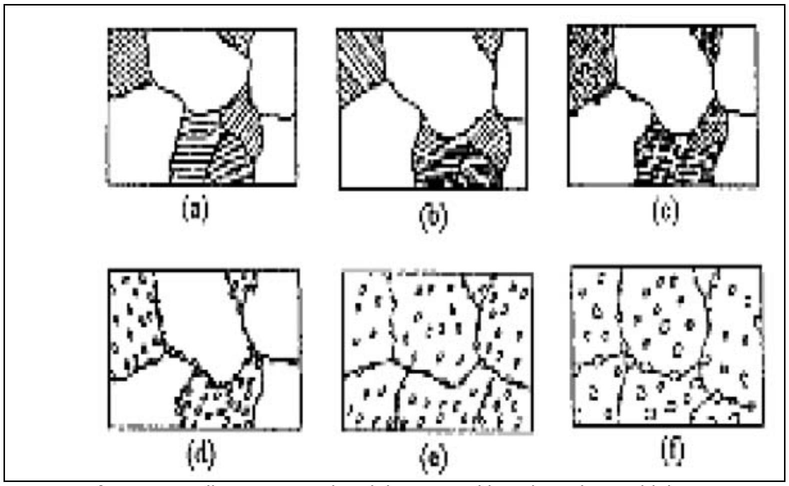

Figure 5. Perlite's stages when it is exposed by a long time at high temperature

Table-V Perlite stage description

Stage	Description	% of life consumed
A	New material, ferrite (clear area) and very thin perlite (grey area compound by ferrite + laminar carbide)	0-6%
B	First sign of carbide spheroidization.Carbides precipitation at the grain boundaries	6-12%
C	Intermediate stage, perlite spheroidization is appreciable, some carbide sheets are visible	12-27%
D	Spheroidizaton of carbides from perlite is finished	27-65%
E	Dispersed carbides (no ferritic-perlitic structure)	65%90%
F	Carbides coalescence	90%-100%

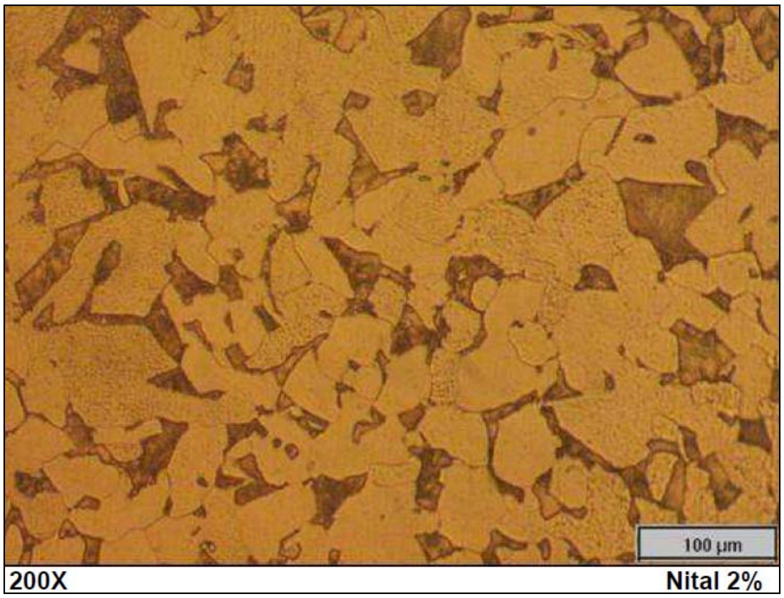

Figure 6. Ferritic matrix plus incipient perlitic globulization.Stage "B"

2.1.3 Degradation assessment and remaining life calculation

In this stage all information gathered during inspection phase is collected and analyzed to perform degradation analysis, remaining life calculation and/or fitness for service assessment in case of detect flaws that are beyond design codes limits. For this case study two mechanisms are assessed, general corrosion and metallurgical changes.

General corrosion: Corrosion rate has been determined per each tube pass. Spot UT thickness reading has been used to calculate the corrosion rate per each tube pass. Using nominal thickness, minimum thickness per design (API 530) and current thickness, the remaining life calculation has been performed. From figure 7 it can be appreciated that tube pass # 3 has the higher corrosion rate and the minimum remaining life. In table VI remaining life per each pass is summarized.

$$RL(y) = \frac{Current\ \ thickness(mm) - Minimum\ \ thickness(mm)}{Corrosion\ \ rate(mm/y)}$$

$$CR(mm/y) = \frac{\Pr evious\ \ thickness - Current\ \ thickness}{time\ \ between\ \ inspection(y)}$$

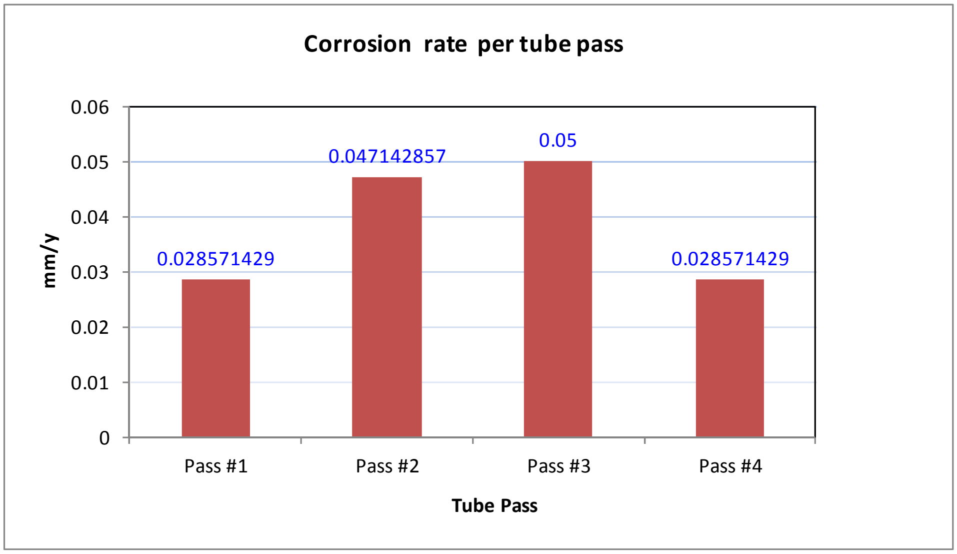

Figure 7. Corrosion rate per tube pass

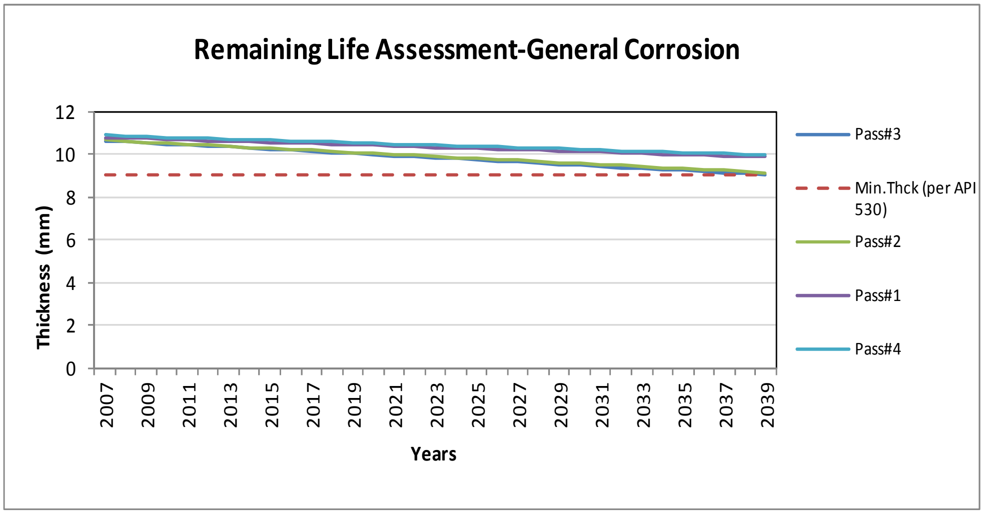

Figure 8. Remaining life per tube pass

Table-VI Remaining life per each pass

Pass #	Corrosion rate (mm/y)	Remaining Life (years)

Pass #1	0.028571429	61.95
Pass #2	0.047142857	35
Pass #3	0.05	32.4
Pass #4	0.028571429	65.45

Metallurgical changes: First metallographic replicas analysis performed in 2004 no found any metallurgical damage, meaning that in 2004 the tube's metallurgical stage was "A", based on figure 5. In 2011 the metallographic analysis had shown an incipient spheroidization. The last tube's stage is "B". Based on this information an approximately degradation analysis can be performed to know what is the expected end of tube's life from metallurgical point of view. Assuming the end of tube's life when they reach the stage "E-F" (80-90% of lifetime consumed).

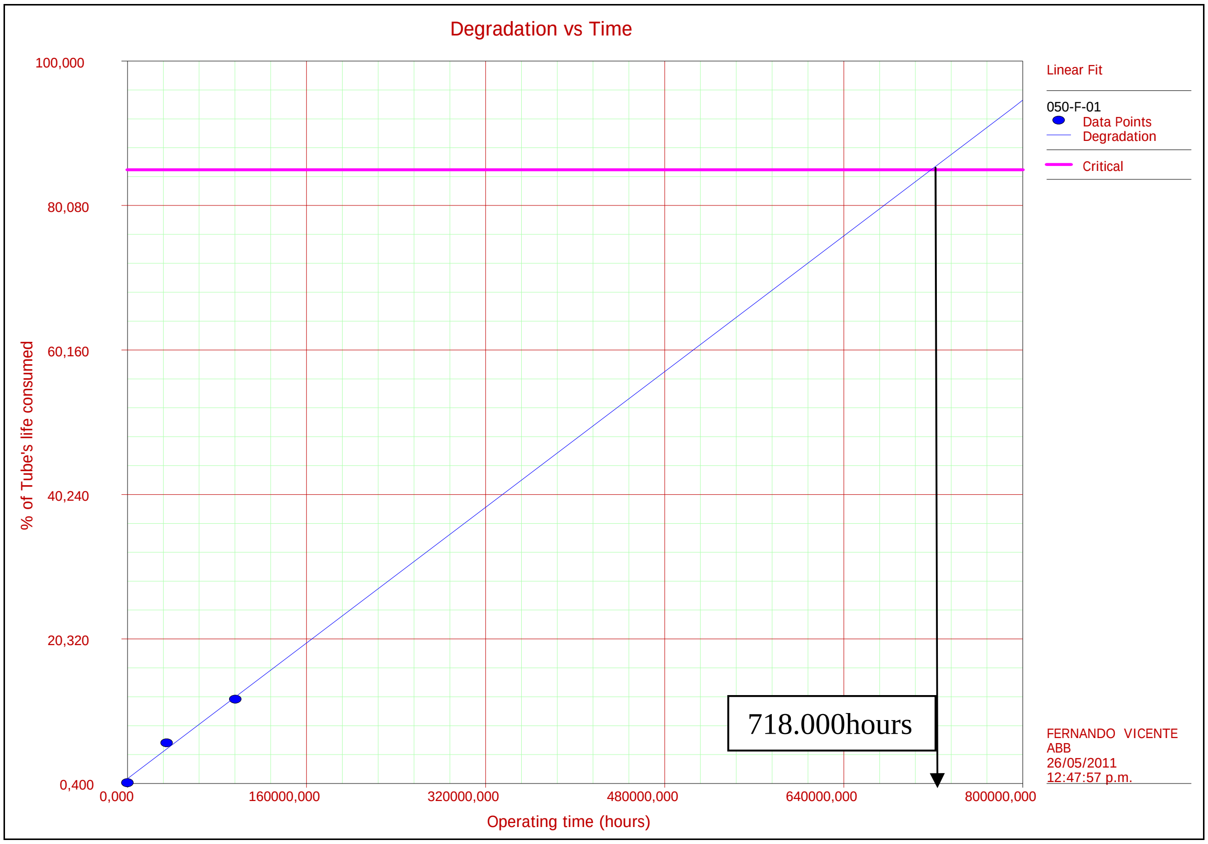

Figure 9. Metallurgical Remaining life calculation

The remaining life is calculated based on the following equations:

$$RL(years) = Calculated \quad \deg radation \;\; time - current \;\; operation \;\; time$$
$$RL(y) = 718000 hours (82 years) - 96360 hours (11 years) = 621640 hrs (71 years)$$

This means that damage mechanism general corrosion is leading the remaining life of the gas heater tubes.

Table-VII Remaining life per damage mechanism

Pass #	RL(years)-Metallurgical changes	RL(years)-General corrosion
Pass #1	71	61.95
Pass #2		35
Pass #3		32.4
Pass #4		65.45

The appropriate inspection must provide the information necessary to determine that all of the essential sections of the gas heater's tubes are safe to operate until next scheduled inspection. Once tube's remaining life is calculated a better knowledge about when next scheduled internal inspection should carried out, instead of performing internal inspection at fixed frequency. The best cost-effective way to determine the optimum tube's interval inspection is through condition based maintenance via degradation analysis (as shown before). A rule thumb adopted is to perform the next scheduled inspection at one half of tube's remaining life time and no more than 10 years. The table VIII shows the adjusted interval inspection defined by the knowledge of tube's condition got it after degradation analysis.

Table-VIII Adjusted interval inspection

Inspection type	Fixed Interval inspection (years)	Adjusted interval inspection (years)
Visual internal	**5**	**Min (1/2RL;10y)**
UT thickness measurement	**5**	**Min (1/2RL;10y)**
Metallographic replicas and hardness measurement	**5**	**Min (1/2RL;10y)**

The adjusted interval inspection will be valid if the IOW parameter (Integrity Operating Window) are within the limits. For example, if maximum tube skin temperature is exceeded, a new assessment needs to be performed and new interval inspection need to be defined. Integrity operating windows (IOWs) are those preset limits on process variables that need to be established and implemented in order to prevent potential breaches of containment that might occur as a result of not controlling the process sufficiently to avoid unexpected or unplanned deterioration or damage to pressure equipment. Operation within the preset limits should result in predictable and reasonably low rates of degradation. Operation outside the IOW limits could result in unanticipated damage, accelerated damage and potential equipment failure from one or more damage mechanisms. For gas heater's tubes these operating parameters can be, maximum tube skin temperature, %CO_2, %H_2S, water content in gas stream.

CONCLUSIONS

Gas heater's tubes that are designed by API-530 and is not in the creep range and the integrity operating window parameters remains within established limits the tube's useful life is much bigger than 11.4 years as defined in the standard. Replacing heater tubes at fixed time before the end of useful life increase the equipment cost dramatically, replacing tubes after the end of useful life can be catastrophic. The prediction of tube remaining life is not an easy task; tube life can be shortened by uneven heating, coke buildup, or short-term high rates of corrosion. This event cannot be predicted, is for this reason process control, IOW parameters and inspection analysis are combined activities developed to predict the tubes remaining life.

This article showed how an effective tube management inspection program can be used to help to maintenance engineers and plant manager to select the optimal life management strategy for gas heater's tubes. Due to the world financial crisis, companies are forcing to reduce maintenance cost and this kind of maintenance strategy presented in this article is a powerful tool to optimize the inspection plan.

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