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***From The Editor's Desk*:**

[*This article is taken from June 21 issue of Houston Chronicle and condensed for space*]

The oil bust is shaking up the pecking order of Houston's elite companies, elevating those with less exposure to unstable prices for the region's milk and honey – oil and gas. Many of the oil producers that speckled the top of last year's list have fallen, nursing their wounds after deep oil downturn began last summer. But that's not to say Houston's start faded all that much last year.

The data shows that collectively, the 100 best performing companies in Houston amassed 7% more revenue than they did in 2013, even with the sudden collapse of oil prices weighing down on their balance sheets in the second half of 2014. Nine energy infrastructure companies landed among top 30 companies on the list, buoyed by a fee-based business model that doesn't fluctuate with energy prices.

Regulated power markets have kept electricity companies stable, and infrastructure companies will collect fees for pipelines and terminals, no matter what the price is for oil and gas. The companies that pump oil out of the ground, however, are much more exposed to prices, and are much more risky because the prices are outside of anyone's control.

The list of 100 best performing companies reflects both the prosperous first half of 2014 and the oil bust in the second half, and captures a shift in the concentration of economic power from the west side of Houston, the corporate domain of oil producers and their equipment suppliers, to the east, where pipelines, crude terminals, oil refineries and petrochemical plants abound. Inside the metro area alone, companies that turn oil and gas into everyday products are planning $25 to $30 billion in big new construction projects. They are likely to be spurred on by cheap feedstock and the availability of construction workers and other laborers who have been let go by thousands during the downturn.

Looking to the future, however, Houston is showing early warning signs that it could slip into a shallow recession in the second half of this year if the oil prices stay low. The full effects of the oil slump didn't really hit corporate finances last year – most of those are playing out now in 2015 with thousands of oil company layoffs. If the employment trends play out the way they have this year, the area's payrolls could decline 2 percent in the second half of 2015. The upstream sector is the major accelerator for the Houston economy; the key question for Houston regarding oil is: How low for how long?

While some economists believe that massive expansion in the petrochemical sector on the east side will probably just barely keep Houston from falling into recession this year, they also opine that 2014 is really going to look good in the rearview mirror.

The cover image is courtesy of Fourinox in Green Bay, WI. Fourinox is a custom fabrication company specializing in the manufacture of ASME, CE and API certified process and pressure vessels.

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WHAT IS UPSTREAM, MIDSTREAM AND DOWNSTREAM IN OIL & GAS SECTOR?

The oil & gas industry is massive and very complex. It is also essential for today's economy. No modern society can run smoothly without oil & gas.

There are multitude of different functions that must be performed to get the oil and gas from the underground or under water to the consumer. The industry is divided into three major sectors: upstream, midstream and downstream.

Upstream Sector

The upstream sector is also commonly known as exploration and production (E&P) sector. This sector includes searching for potential underground or underwater crude oil and natural gas fields, drilling of exploratory wells, and subsequently drilling and operating the wells that recover and bring the crude oil and/ or raw natural gas to the surface.

<u>Exploration</u>

- Conducting the geological and geophysical surveys required to explore possible sites
- Searching for potential underground or underwater crude oil and natural gas fields
- Obtaining leases and permissions from the landowners to drill

<u>Production</u>

- Being efficient and cost effective with materials, time and labor in the recovery of oil & gas
- Gathering and short term storage of oil and gas
- Plug and abandonment, which marks the end of a well, can be anywhere from a few months to decades later, depending on the size of the underground/ underwater field

The business side of the upstream sector is complex, very risky, and high reward endeavor. It is greatly affected by outside forces like political instabilities, international conflicts and even seasonal weather patterns. The sector is highly regulated by government and environmental entities. The technology is contantly growing and changing at a fast pace.

Midstream Sector

The midstream sector involves the transportation (by pipeline, rail, barge, oil tanker or truck), storage and wholesale marketing or crude or refined petroleum products. Pipelines and other transportation systems can be used to move crude oil from production sites to refineries, and deliver the various refined products to downstream distributors. Natural gas pipeline networks aggregate gas from natural gas purification plants and deliver it to dwonstream customers such as utilities. It is all about taking the crude or natural gas retrieved in the upstream sector and getting it to the downstream facilities so that it can be turned into various finished products. it is the conduit between the upstream sector and the downstream sector.

Sometimes midstream operations are often taken to include some elements of the upstream and downstream sectors. For example, the midstream sector may include the natural gas processing plants that purify the raw natural gas as well as removing and producing elemental sulfur and natural gas liquids (NGL) as finished end products.

Pipelines represent the most common way that the oil and gas is transported. To accomplish this a vast network of pipelines are constructed and maintained. Som eof the most common factors encountered in transporting via pipelines are:

- Compressor stations/ pump stations: Getting the oil and gas to travel long distances requires extreme amount of pressure. Even with high pressure, the pipeline routes need compression/ pump stations at regular intervals for continued flow.
- Geopolitical: It is not uncommon for oil and gas to travel through multiple countries. Building and monitoring pipeline requires successfully navigating the political waters, getting the right permits, complying with the local regulations and negotiation taxes.
- Terrain: The pipeline will need to travel across different terrains. For instance, it may begin its journey over flat land, but travel across mountaineous regions, through deserts, swamps or frozen lands. The wide variety of different terrain types will require unique considerations with regard to the pipeline construction and maintenance.
- Maintenance: The challenge of maintaining the pipeline is one of the most cricial aspects of pipelines. It is imperative to prevent pipes from cracking or bursting because not only would such an accident be expensive, it would also be devastating to the environment, and could also cause significant problems in terms of supply and demand.

Downstream Sector

The downstream industry includes oil refineries, petrochemicals plants, petroleum product distributors, retail outlets and natural gas distribution companies. It refers to the refining, processing and purifying of crude oil and natural gas, including efforts that are made to market and distribute crude oil and natural gas related products. This includes products such as petrol, diesel oil, jet fuel, lubricants, heating oil, asphalt, waxws, and a plethora of differetn petrochemicals.

The downstream sector also includes hydrodesulphurization – a process which sees sulfur containing compound found in crude oil converted into gaseous hydrogen sulfide. Natural gas processing plants are also used to remove hydrogen sulfide and sulfur containing mercaptans from raw natural gas. The hydrogen sulfiude by-product is then converted into elemental sulfur.

Downstream operations are strongly connected with refining industry because it is this segment of production chain that diesel, kerosene, jet fuel oil and all other petroleum liquids get synthesized. Not all refineries can deal with a broad range of crude oils so there are certain production boundaries. Nevertheless, business is straigth forward: refineries buy crude oil, they refine it and then sell the synthesized outputs.

PROCEDURES FOR POSTWELD HEAT TREATMENT

Heat treatment, in the context of ASME Code, is used for stress relieving of weldments for those material P-numbers and material thicknesses as required by the code sections to which the fabrication is being done. It is used to achieve a desirable improvement in the characteristics of the material, or to regain those characteristics which may have been adversely affected by production processes such as welding/ bending/ forming etc. In this article, we will discuss just one heat treatment process, namely, Post Weld Heat Treatment, or PWHT.

As a result of welding processes used to join metals together, the base materials near the weldment, the deposited weld metal and, in particular, the heat affected zones (HAZ) transform through various metallurgical phases. Depending on the chemistry of metals in these areas, hardening occurs in various degrees, dependent mainly upon carbon content. Again, this is particularly true in the HAZ adjacent to the weld metal deposit where the highest stresses due to melting and solidification result.

PWHT is performed after welding and is designed to relieve a proportion of these imposed stresses by reducing the hardness and increasing ductility, thus reducing danger of cracking in the vessel weldments. It reduces and redistributes the residual stresses in the material that have been introduced by welding. The extent of the relaxation of the residual stresses depends on the material type and composition, the temperature of PWHT, and the soaking time at that temperature. A commonly used guideline for PWHT is that the joint should be soaked at peak temperature for 1 hour for each 1 in. (25mm) of thickness although for certain cases a minimum soak time will be specified.

Benefits and Detrimental Effects

Three primary benefits of PWHT are tempering, relaxation of residual stresses, and hydrogen removal. Consequential benefits such as avoidance of hydrogen induced cracking, dimensional stability, and improved ductile toughness and corrosion resistance result from the primary benefits. It is important that PWHT conditions be determined based on the desired objectives.

Sometimes ageing/ precipitation processes can cause deterioration in the mechanical properties of steel, in which case, specialist advice should be taken on the appropriate times and temperatures to use. Excessive or inappropriate PWHT temperatures and/ or long holding times can adversely affect properties. The adverse effects can include distortion, over-softening, decreased tensile strength, and reduced creep strength and notch toughness (generally caused by embrittlement due to precipitate formation).

The influence of PWHT on properties primarily depends upon the composition of weld metal and base metal, and prior thermal and mechanical processing of the base metal. If PWHT is run at higher than specified temperatures and/ or longer specified soak times, the work piece can become more brittle than desired. Control of heating and cooling rates, holding temperature tolerances, and the times at temperature are extremely important, and must be carefully controlled in order to realize the full benefit of PWHT process.

What causes high residual stresses?

Welding involves the deposition of molten metal between two essentially cold parent metal faces. As the joint cools, the weld metal contracts but is restrained by the cold metal on either side; the residual stress in the joint therefore increases as the temperature falls. When the stress has reached a sufficiently high value (the yield point at that temperature), the metal plastically deforms by means of a creep mechanism so that the stress in the joint matches the yield strength. As the temperature continues to fall, the yield strength increases, impeding deformation, so that at ambient temperature the residual stress is often equal to the yield strength.

To reduce this high level of residual stress, the component is reheated to a sufficiently high temperature. As the temperature is increased, the yield strength falls, allowing deformation to occur and residual stress to decrease until an acceptable level is reached. The component would be held at this temperature (soaked) for a period of time until a stable condition is reached and then cooled back to room temperature. The residual stress remaining in the joint is equal to the yield strength at the soak temperature.

What are the drivers for PWHT?

The need for PWHT depends on several factors: material, service requirements, welding parameters, and the likely mechanism of failure. In some codes, PWHT is mandatory for certain material types or thicknesses. These fabrication code requirements are aimed at reducing susceptibility to brittle fracture, and as such is targeted to improve notch toughness and relax residual stresses. But where there is an option, cost and potential adverse effects need to be balanced against possible benefits. The energy costs are generally significant due to the high temperatures and long times involved, but costs associated with time delays may be more important.

The need for PWHT based upon service environment is not treated by fabrication codes. Instead, guidance may be found in recommended practices regarding service environment. Applying PWHT for "service" can have a variety of objectives. Reduction of hardness and stress relaxation are two of the more common objectives related to service environments. It is important to note that the threshold stress levels in such cases are often less than those required for brittle fracture related concerns, and more detailed requirements may therefore apply.

Some points to remember:

- PWHT is designed to return a metal as near as possible to its prefabrication state of yield, ultimate tensile and ductility.
- The rate of temperature rise, holding time at temperature and rate of cooling are vitally important. For this reason, the furnace thermocouples must measure metal temperature, not furnace atmospheric temperature.

Understanding the areas of the work piece

When dealing with the work piece, there are some important areas and key terms one needs to be aware of. They are: weld area, heat affected zone (HAZ), and soak band (SB).

<u>Weld Area and Heat Affected Zone</u>

Weld area is the widest width of butt or attachment weld. HAZ is the area of the base material which has had its microstructure and properties altered by welding, heat intensive cutting, and sometimes bending/ working. In any heat treatment process, the primary objective is to fix this – to restore HAZ to its normal condition.

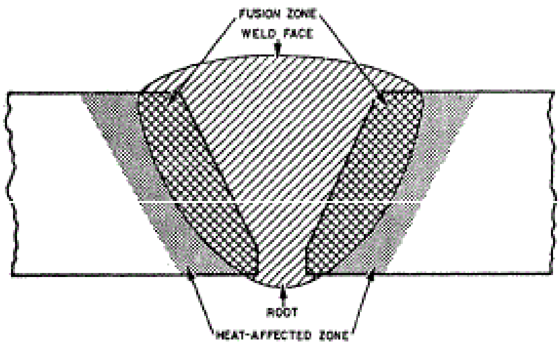

Figure 1: Weld Area and Heat Affected Zones

<u>Soak Band</u>

The soak band consists of the through thickness volume of metal, which is heated to the minimum but does not exceed the maximum required temperature. As a minimum, it should consist of the weld metal, HAZ, and any portion of the base metal adjacent to the weld being heated. The soak band width is established to ensure that the required volume of metal achieves the desired effect.

ASME Code Procedures for PWHT

The ASME Code procedures for post weld heat treatment (PWHT) are provided in paragraph UW-40 of Section VIII, Division 1. Eight procedures are listed in the paragraph that can be broadly grouped under one of the three types given below:

Depending on the size of the vessel and capacity of the furnace (size and maximum temperature), a full or partial PWHT is performed. In full PWHT, there are two types of firing methods. The most common one is the furnace PWHT wherein the vessel is loaded inside the furnace and heated to the required level in a single firing. This is the most desirable type of PWHT because all parameters in the heating, soaking and cooling cycle can be controlled well. However, the availability of such furnaces are the only constraint. If PWHT in one go is not possible due to the size of the vessel, paragraph UW-40 of the ASME VIII-1 code permits the use of part-by-part PWHT with sufficient overlap of the heated zones.

In the second method, the vessel itself is made the furnace by providing burners at appropriate points and by giving insulation all around the pressure vessel. This method is called internal firing and is very much dependent on the skill of those that perform this feat.

The third method is to do the PWHT of welds alone when the design permits, using electrical resistance heating. Here again, proper overlap between two PWHT zones shall be given.

The eight procedures listed in paragraph UW-40 are as follows:

1) Heating of pressure vessel as a whole in an enclosed furnace. This is the preferred method and is recommended to be used wherever practical.
2) Heating the pressure vessel in more than one heat in a furnace, provided the overlap of the heated sections of the pressure vessel is at least 5 ft (1.5 in). When this procedure is used, the portion outside of the furnace shall be shielded so that the temperature gradient is not harmful. The cross section where the vessel projects from the furnace shall not intersect a nozzle or other structural discontinuity.
3) Heating of shell sections and/ or portions of pressure vessel to post weld heat treat longitudinal joints or complicated welded details before joining to make the completed pressure vessel. When the vessel is required to be postweld heat treated. and it is not practical to postweld heat treat the completed vessel as a whole or in two or more heats, as provided in 2) above, any circumferential joint not previously postweld heat treated may be thereafter locally postweld heat treated by heating such joints by any appropriate means that will assure the required uniformity. For such local heating, the soak band shall extend around the full circumference. The portion outside the soak band shall be protected so that the temperature gradient is not harmful. This procedure may also be used to postweld heat treat portions of new vessels after repairs.
4) Heating the vessel internally by any appropriate means and with adequate indicating and recording temperature devices to aid in control and maintenance of a uniform distribution of temperature in the pressure vessel wall. Previous to this operation, the pressure vessel should be fully enclosed with insulating material, or the permanent insulation may be installed provided it is suitable for the required temperature. In this procedure, the internal pressure should be kept as low as practicable, but shall not exceed 50% of MAWP at the highest metal temperature expected during the postweld heat treatment period.
5) Heating a circumferential band containing nozzles or other welded attachments that require PWHT in such a manner that the entire band be brought up uniformly to the required temperature and held for a specified time.

The soak band should extend around the entire pressure vessel, and shall include nozzle or welded attachment. The circumferential soak band width may be varied away from the nozzle or attachment weld requiring PWHT, provided the required soak band around the nozzle or attachment weld is heated to the required temperature and held for the required time.

As an alternative to varying the soak band width, the temperature within the circumferential band away from the nozzle or attachment may be varied and need not reach the required temperature, provided the required soak band around the nozzle or attachment weld is heated to the required temperature, held for the required time, and the temperature gradient is not harmful throughout the heating and cooling cycle.

The portion of the vessel outside of the circumferential soak band shall be protected so that the temperature gradient is not harmful. This procedure may also be used to postweld heat treat portions of pressure vessels after repairs.

6) Heating the circumferential joint of a pipe or tubing by any appropriate means using a soak band that extends around the entire circumference. The portion outside the soak band shall be protected so that the temperature gradient is not harmful.

7) Heating a local area around nozzles or welded attachment in the larger radius section of a double curvature head or a spherical shell or head in such a manner that the area is brought up uniformly to the required temperature and held for a specified time. The soak band shall include the nozzle or welded attachment. The soak band shall include a circle that extends beyond the edges of the attachment weld in all directions by a minimum of t or 2 in (50mm), whichever is less. The portion of the pressure vessel outside of the soak band shall be protected so that the temperature gradient is not harmful.

8) Heating of other configurations. Local area heating of other configurations such as “spots” or “bulls eye” local heating not addressed in 1) through 7) above is permitted provided that other measures are taken that consider the effect of thermal gradients, all significant structural discontinuities and any mechanical loads which may be present during PWHT. The portion of the pressure vessel or component outside the soak band shall be protected so that the temperature gradient is not harmful.

In the above procedures, the soak band is defined as the volume of metal required to meet or exceed the minimum PWHT temperatures listed for UCS, UNF, UHA and UHT materials. As a minimum, soak band shall contain the weld, heat affected zone, and a portion of base metal adjacent to the weld being heat treated. The minimum width of this volume is the widest width of the weld PLUS 1t or 2 in, whichever is less, on each side of the weld. Term “t” is the nominal thickness of the metal used in specifying PWHT requirements. For pressure vessels or parts of pressure vessels being postweld heat treated:

1) Welded joints connecting parts of same thickness using a full penetration butt weld, the nominal thickness is the total depth of weld exclusive of any permitted weld reinforcement.

2) For groove welds, the nominal thickness is the depth of groove.

3) For fillet welds, the nominal thickness is the throat dimension. If fillet weld is used in conjunction with groove weld, the nominal thickness is the depth of the groove or the throat dimension, whichever is greater.

4) For stud welds, the nominal thickness is the diameter of the stud.

5) When welded joint connects parts of unequal thickness:

    a. For two adjacent butt-welded parts, including head-to-shell connection, the nominal thickness is the thinner of the two parts.

    b. For connection of intermediate head to shell, the nominal thickness is the thickness of shell or head, whichever is greater.

c. For connection of tubesheets, flat heads, covers, flanges, or similar construction to the shell, the nominal thickness is the thickness of the shell.

d. For connection of welded nozzles or small fittings to the shell or head, the nominal thickness is the thickness of the weld across the nozzle neck or shell or head or reinforcing pad or attachment fillet weld, whichever is the greater.

e. For nozzle neck to flange connections, the nominal thickness is the thickness of nozzle neck at the joint.

f. For connection of a non-pressure part to a pressure part, the nominal thickness is the thickness of weld at the point of attachment.

g. For tub-to-tubesheet connection, the nominal thickness is the thickness of the weld.

h. When weld overlay is the only welding applied, the nominal thickness is the thickness of the weld metal overlay.

6) For repairs, the nominal thickness is the depth of the repair weld.

The tables, when provided for the PWHT temperatures and the holding times, list requirements that include minimum holding temperatures, the maximum holding temperatures, and minimum holding time at nominal temperature for weld thicknesses.

PWHT requirements for UCS materials are listed in Tables UCS-56-1 through UCS-56-11 as follows:

UCS-56- 1	P. No. 1
UCS-56- 2	P. No. 3
UCS-56- 3	P. No. 4
UCS-56- 4	P. No. 5A, 5B and 5C
UCS-56- 5	P. No. 9A
UCS-56- 6	P. No. 9B
UCS-56- 7	P. No. 10A
UCS-56- 8	P. No. 10B
UCS-56- 9	P. No. 10C
UCS-56- 10	P. No. 10F
UCS-56- 11	P. No. 15E

PWHT of UNF materials is not normally desired. PWHT requirements are provided for welded castings of SB-148 Alloy CDA954, all products of zirconium grade R600705, and nickel alloys UNS Nos. N08800, N08810 and N08811.

PWHT requirements for high alloy steels are provided in Tables UHA-32-1 through UHA-32-6 as follows:-

UHA-32- 1	P. No. 6
UHA-32- 2	P. No. 7
UHA-32- 3	P. No. 8
UHA-32- 4	P. No. 10H
UHA-32- 5	P. No. 10I

UHA-32- 6	P. No. 10K
UHA-32-7	P. No. 45

PWHT requirements for UHT materials are provided in Table UCS-56.

The minimum temperatures referred to above shall be the minimum temperature of the plate material of the shell or head of any pressure vessel. Where more than one pressure vessel or pressure vessel parts are post weld heat treated in one furnace charge, thermocouples shall be placed on the vessels at the bottom, center and top of the charge, or in other zones of possible temperature variations so that the temperature indicated shall be true temperatures for all pressure vessels or pressure vessel parts in these zones.

When pressure parts of two different P-number groups are joined by welding, the PWHT shall be that specified according to either UCS-56 or UHA-32, for the material requiring higher PWHT temperature.

PWHT, when required, shall be done before the hydrostatic test and after any welded repairs. Exceptions are provide for weld repairs to P. No. 1 Group No. 1, 2 and 3 materials, P. No. 3, Group No. 1, 2 and 3 materials, and to weld metals used to join these materials in paragraph UCS-56(f). A preliminary hydrostatic test to reveal leaks prior to PWHT is permitted.

Source: ASME Boiler and Pressure Vessel Code, Section VIII, Division 1

WHAT ARE P-NUMBER?

To reduce the number of welding procedure qualifications required, base metals have been assigned P-numbers by ASME Boiler and Pressure Vessel Code. Ferrous metals which have specified impact test requirements have also been assigned Group numbers within the P-numbers. These assignments have been based on comparable base metal characteristics such as composition, weldability, and mechanical properties. P-numbers are generally assigned as follows:

Base Metals	P-numbers
Steel and steel base alloys	P1 through P11
Aluminum and aluminum base alloys	P2X
Copper and copper base alloys	P3X
Nickel and nickel base alloys	P4X
Titanium and titanium base alloys	P5X
Zirconium and zirconium base alloys	P6X

The table below is a guide and an approximate summary of ASME data for the P-numbers assigned to base metals (Welding only):

P-numbers	Base Metal
1	Carbon manganese steels (Four group numbers)
2	Not used
3	½ Molybdenum, or ½ Chromium and ½ Molybdenum (Three group numbers)
4	1¼ Chromium and ½ Molybdenum (Two group numbers)
5A	2¼ Chromium and 1 Molybdenum
5B	2¼ Chromium and ½ Molybdenum, or 9 Chromium and 1 Molybdenum (Two group numbers)
5C	Chromium, Molybdenum and Vanadium (Five group numbers)
6	Martensitic stainless steels – Grades 410, 415 and 429 (Five group number)
7	Ferritic stainless steels – Grades 409 and 430

P-numbers	Base Metal
8	Austenitic stainless steels Group 1 – Grades 304, 316, 317 and 347 Group 2 – Grades 309 and 310 Group 3 – High manganese grades Group 4 – High molybdenum grades
9A, B, C	2 to 4 nickel steels
10A, B, C, F	Various low alloy steels
10H	Duplex and super duplex stainless steel
10I	High chromium stainless steel
10J	High chromium and molybdenum stainless steel
10K	High chromium, molybdenum and nickel stainless steel
11A	Various high strength low alloy steels (Six group numbers)
11B	Various high strength low alloy steels (Ten group numbers)
12 to 20	Not used
21	High aluminum content – 1000 and 3000 series
22	Aluminum 5000 series – 5052 and 5454
23	Aluminum 6000 series – 6061 and 6063
24	Not used
25	Aluminum 500 series – 5083, 5086 and 5456
26 to 30	Not used
31	High copper content
32	Brass
33	Copper silicone
34	Copper nickel
35	Copper aluminum

P-numbers	Base Metal
36 to 40	Not used
41	High nickel content
42	Nickel and copper – Monel 500
43	Nickel, chromium and iron – Inconel
44	Nickel and molybdenum – Hastelloy B2, C22, C276 and X
45	Nickel and chromium
46	Nickel, chromium and silicone
47	Nickel, chromium and tungsten
48 to 50	Not used
51, 52, 53	Titanium alloys
61, 62	Zirconium alloys

ASME Section VIII, Division 1 currently requires PWHT for materials greater than the following thickness:

P-number 1 (Groups 1, 2 and 3)	> 1½ inch
P-number 3 (Groups 1 and 2)	> 5/8 inch
P-number 4 (Groups 1 and 2)	> 5/8 inch
P-number 5A (Group 1)	> 5/8 inch

P1 carbon steels are generally defined as steels that contain up to 0.35% carbon, 0.6% silicon and 1.65% manganese. When silicon and manganese exceed these amount, the steel is called an alloy steel. Residual amounts of other alloying elements such as nickel, chromium and molybdenum are often found in carbon steels which were in the scrap used in making the steel. These elements must be controlled for carbon steels that are arc welded because their presence can cause problems.

Most of P1 materials fall under Groups 1 or 2. It varies depending on carbon and manganese content and tensile strength. If carbon content is low and tensile strength is average (say 60,000 psi), it could be Group 1. If carbon/ manganese content and silicon content is more and tensile strength is high (say 70,000 psi and above), it could be Group 2.

P2 materials are not listed in ASME Code. Historically, ASME used P2 for wrought iron, however wrought iron pressure vessels are no longer manufactured.

P3, P4, P5A, P5B and P5C materials are the low alloy carbon-molybdenum and chromium-molybdenum steels. The principal distinction between welding these steels and welding carbon steels is the increased hardenability and therefore cracking susceptibility which occurs with increasing alloy content. There is increasing preheat and PWHT requirements in the Code for these steels as alloy content increases with P-number. A guide for selecting preheat and PWHT is the carbon equivalent (CE). One well-known formula for CE is:

$$\mathrm{CE} = \%\mathrm{C} + \frac{\%\mathrm{Mn}}{6} + \frac{\%\mathrm{Ni}}{15} + \frac{\%\mathrm{Cr}}{6} + \frac{\%\mathrm{Mo}}{4} + \frac{\%\mathrm{V}}{5}$$

Steels having CE by this formula of less than 0.40% usually require no preheating. Steels with CE of 0.40% to 0.60% usually require preheating. When CE by this formula exceeds 0.60%, it is usually necessary to use both preheating and post-heating. It must be noted, however, that CE is based on base metal composition and does not include other variables such as heat treated condition or degree of restraint. Therefore, at best, it is only an approximate measure of weldability and susceptibility to weld cracking. **Code requirements must be met**.

P6 and P7 materials are those high alloy steels commonly referred to as martensitic (P6) and ferritic (P7) stainless steels. Whether a stainless steel is ferritic, martensitic or austenitic depends on a complex relationship between composition and thermal history. We can only say that P6 materials are "predominantly" martensitic and P7 materials are "predominantly" ferritic.

Cracking due to martensitic formation is the primary welding concern with P6 materials. If enough carbon is present to increase the martensitic hardness, substantial preheats and retarded cooling is necessary. Embrittlement due to ferritic grain growth is the usual welding concern with P7 materials requiring heating input and maximum interpass temperature to be closely controlled.

P8 materials cover austenitic chromium nickel stainless steels. Welding concern with austenitic stainless steels include proper filler meal grade selection, heat input control to avoid distortion and sensitization, control of delta ferritic content to avoid hot cracking and avoiding sigma phase embrittlement.

P23 materials cover aluminum alloys in which the predominant alloying elements are magnesium and silicon. These are identified in the Aluminum Association as 6xxx alloys (e.g. 6061). The primary welding consideration with these alloys are the rapid heat conduction from the weld area and overcoming the surface layer of aluminum oxide. Welding effects on the heat treat or temper condition of the base metal may also be important.

P35 materials cover the aluminum bronze copper alloys. Alloys 7 to 10% aluminum are the most frequently welded.

P43 materials cover the group of nickel base alloys known generally as Inconel. Nickel base alloys find wide application where corrosion resistance and/ or high service temperatures are a major concern. Hot cracking due to sulfur, halogen or heavy metal (e.g. lead) contamination is a primary concern when welding these materials.

P51 material is titanium. Titanium is highly reactive metal requiring high level of care in shielding the hot base material from atmospheric oxygen and nitrogen. Auxiliary lead and trailing inert gas shielding is sometimes required. Welding for very sensitive applications is sometimes performed in an inerted chamber. From a practical standpoint, titanium can only be arc welded to itself.

Source: Welding Technology *by* Roger Cantrell

HEAT TRANSFER EFFICIENCY

Heat transfer efficiency is an important aspect that must be considered while designing shell-and-tube heat exchangers. In this article, we will look at various factors that affect the heat transfer efficiency of an heat exchanger.

Fouling

When designing shell-and-tube heat exchangers, we should use the available pressure drop to maintain high velocities through the heat exchanger. Safety factor should not be used to allow for future pressure drop due to fouling. Use of such factors will force the mechanical engineer who designs the heat exchanger to use lower velocities in the design. Then the feared fouling will occur, and the ΔP safety factor will be consumed.

But suppose we are operating a heat exchanger subject to rapid rates of initial fouling. The starting heat transfer coefficient U is 20 Btu/(h-ft^2-^{o}F). Four months later, the U value has dropped to 38. The calculated clean tube side velocity is 1½ ft/s. This is too low, but what can be done?

Multipass Exchangers

It is possible sometimes to convert a two pass bundle to a four pass bundle by adding and changing the configuration of baffle plates in the channel head, and by adding a baffle plate at the other end of the heat exchanger. See Figure 1 or Figure 2.

The resulting four-pass tube bundle will have a tube-side velocity twice as high as it did when it was a two-pass heat exchanger. Experience has shown that in many services, doubling this velocity will reduce the fouling rates by an order of magnitude. That is fine – but what about the pressure drop?

When we convert a tube bundle from two to four pass, the pressure drop increases by a factor of 8. For example, assume that the two-pass ΔP was 5 psig. With the same flow, the four-pass ΔP would be 40 psig. Even after several years of operation, the pressure drop of a four-pass heat exchanger will be greater than the ΔP of a two-pass heat exchanger. Also the initial U value of a four-pass heat exchanger, days after it has been returned to service, will be only slightly higher than the U-value of a two-pass heat exchanger. However, the four-pass heat exchanger will maintain its U value with time, far better than will the lower velocity two-pass tube bundle heat exchanger.

The eight-fold increase in the pressure drop is a stiff price to pay for this improvement in long term U value. But remember this – it is the clean ΔP of the tube bundle that will increase by a factor of 8. Let us say that the calculated ΔP for clean tubes is 5 psig in a two-pass configuration, or 40 psig in a four-pass configuration. The tube side is currently operating in two-pass configuration, after 2 years of service, in a badly fouled state. Its ΔP, as measured in the field is 20 psig. After converting to a four-pass configuration, we should expect the heat exchanger to have a ΔP of 50 to 60 psig, rather than 160 psig. Why?

Well, because the doubling of tube-side velocity has promoted turbulence which retards the accumulation of fouling deposits.

Shell Side vs Tube Side

The shell-side cross velocity may be altered in much smaller increments, by changing the tube support baffle spacing. This is one advantage of placing the fluid with poorer heat transfer properties on the shell side. But there is another far more critical, advantage in placing the fluid with poorer heat transfer properties on the shell side.

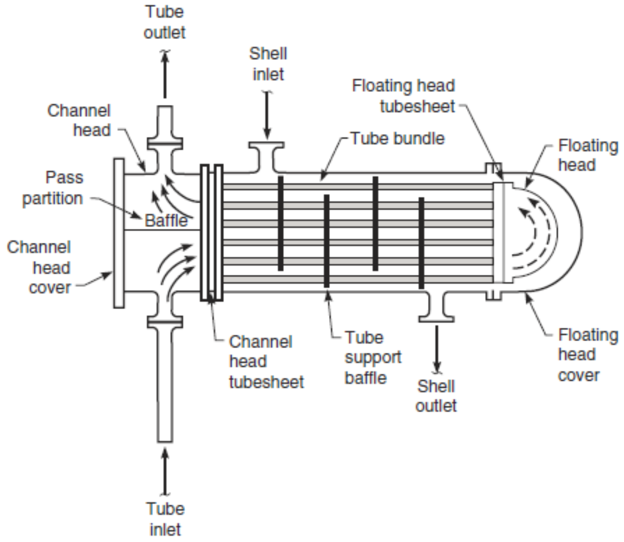

Figure 1: Two-Tube Pass Shell-and-Tube Heat Exchanger

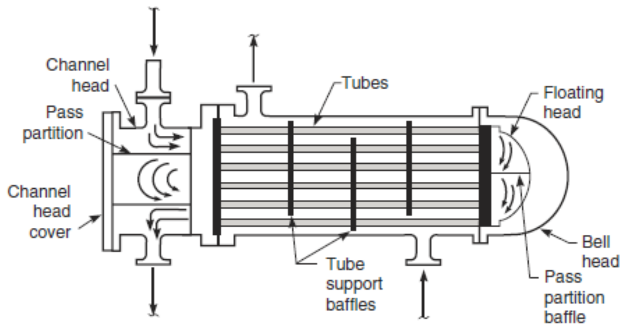

Figure 2: Four-Tube Pass Shell-and-Tube Heat Exchanger

Laminar flow is very bad for heat transfer. After fouling, it is the second biggest reason for low U values. Laminar flow is caused by two factors:

- Low velocities
- High viscosities

A low velocity for liquid is 2-3 ft/s. Velocities greater than 10-12 ft/s may cause erosion of metal surfaces and should be avoided.

A low viscosity is less than 2-3 cP. Viscosities of greater than 50 cP are considered very high. The viscosity of vapors is almost always very low.

When we cool a liquid off, its viscosity markedly increases. Increasing viscosity of fluid from 2 to 40 cP can reduce the observed heat transfer efficiency U from 100 to 25.

The best way to diminish the effect of laminar flow is to place the higher viscosity fluid on the shell side. The shell side of an exchanger is far more resistant to heat transfer loss than is the tube side because of:

- The vortex shedding shown in Figure 3.
- The rapid changes in direction, due to tube support baffles.

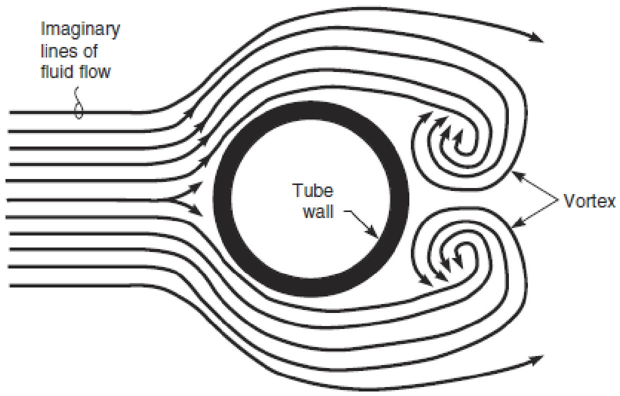

Figure 3: Vortex Formation due to Liquid Flow across a Tube

Purely in terms of heat transfer, it follows that the higher viscosity fluid should be placed on the shell side. Sometimes, pressure and corrosion will force the designer to allocate the higher viscosity fluid to the tube-side. Also, the maintenance department generally prefers that the fouling fluid be placed on the tube side.

Source: A Working Guide to Process Equipment *by*Norman Lieberman and Elizabeth Lieberman

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