MECHANICAL INTEGRITY EVALUATION OF PRESSURE VESSELS

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INTRODUCTION

The Federal Government released a new requirement under the Occupational Safety and Health Administration Standards on May 26, 1992. This code for process safety management was issued under 29 CFR 1910.119 in the Federal Register. The code contains requirements for preventing or minimizing the probability and consequences of catastrophic releases of toxic, flammable or explosive chemicals. Oil production and processing facilities which have processes involving more than 10,000 lbs of flammable liquids or gases and which are "normally manned" are covered under this code.

Under Section J of the code, employers shall develop written procedures to maintain the on-going integrity of pressure vessels, tanks, piping systems, vent and relief systems, pumps, controls and emergency shutdown systems. Employers are also required to document that tests and inspections are consistent with applicable manufacturers' recommendations, industry codes and practices, and that they have actually been performed. ARCO Oil and Gas Company has spent a significant amount of time and resources developing programs to be in compliance with this code. One such program involves determining and documenting the mechanical integrity of pressure vessels.

Prior to the 1930's pressure vessels were typically constructed to the purchaser's specifications. At that time a code was developed to cover standard construction of unfired pressure vessels. This code, the API/ASME Code for Unfired Pressure Vessels for Petroleum Liquids and Gases, was the standard construction code in the petroleum industry until January 1, 1957. At that time, the ASME Section VIII code was developed to cover design, fabrication and inspection of pressure vessels. Most pressure vessels in the petroleum industry which were constructed after 1956 were constructed under ASME Section VIII, Division 1.

There are basically two recognized codes covering the inspection of pressure vessels. One code, the National Board Boiler and Pressure Vessel Inspection Code, NB 23 is often used in chemical plants and refineries. It is also used by companies which have registered with the National Board as Owner/User groups. Another code which is available for use is API 510 - Pressure Vessel Inspection Code. ARCO Oil and Gas Company has chosen to use the API code for inspections of pressure vessels.

API 510 has two specific sections covering inspection and testing of pressure vessels. Section 4 covers all pressure vessels except those used in natural resource service. Under API 510 Section 6 - Alternative Rules for Natural Resource Vessels, owner-user field establishments involved in drilling, production, gathering, transportation, lease processing and treatment of liquid petroleum, natural gas, and associated salt water (brine) may elect to use an alternative set of inspection rules. The only stipulation for this section is that any organization which decides to use this set of alternative rules should apply them to all vessels in that field or service environment. ARCO Oil and Gas Company has elected to use Section 6 for all field and plant pressure vessels.

API Section 6 allows vessels in common circumstances of service and pressure in a field environment to be grouped together as a "class of vessels". This allows inspections to be grouped by class and scheduled over a longer time period on lower risk vessels. ARCO has elected to use common class of vessels to group similar vessels on non-OSHA 1910.119 B and C Class facilities.

RISK CLASSIFICATION

The first requirement to develop a manageable pressure vessel inspection program is to determine the potential risk to the public and employees for each facility or lease. Here a facility can be as large as a plant or as small as a remote well site with accompanying pressure vessels. A checklist should be developed to allow categorization of potential hazards. Each facility is then reviewed to determine the potential risk associated continuing operation. A typical facility risk assessment checklist and ranking is shown as Table 1. This ranking should apply to the entire facility. It may be necessary in a large plant to develop a second ranking based upon process stream classification and associated risk.

Once all facilities have been classified by risk, efforts can be concentrated on those which have higher operational risk or are required to comply with codes such as the OSHA 1910.119. Obviously, all facilities should be reviewed and inspected over time, but such a risk classification allows personnel and resources to be funneled to the most critical areas first.

INVENTORY

Pressure vessels within each lease are inventoried. The inventory should include information such as that listed in Table 2. Unfortunately, many pressure vessels in remote oil field operations may be missing the vessel nameplate. In this case the vessel identification (i.e. free water knock out, treater, etc.), and operating information should be catalogued. It is important to get as much information about each vessel as possible. It is very important to note the presence of an API/ASME or U stamp code compliance indication on the nameplate. Any other compliance markings such as "RT - 1" or "HT" should also be noted. Any documents on initial vessel manufacture such as construction drawings, code calculations, U1A reports or manufacturer's test records should be gathered into a file.

Once an inventory is complete, the vessels should be categorized into those vessels showing indications of some code compliance (such as an API/ASME or U stamp) and those with no indication of code compliance. Vessels which show API/ASME stamps are "grandfathered" under that code and this is considered to be an acceptable indication of code compliance.

PRIORITIZATION

The pressure vessels should be prioritized for initial mechanical integrity examinations. One prioritization method developed involves a review of the service history of the vessel along with a determination of the corrosive potential of the process fluids. A checklist is attached as Table 3 which can be used for scoring individual vessel risk. The inspection priority of the vessel is then determined by multiplying the vessel score by a factor associated with the risk level of the facility. This effectively produces a list of vessels on all facilities which ranks the operational risk in descending order.

This prioritization is done only once when the vessel is reviewed for the initial inspection work. The prioritization is used to schedule the initial vessel external visual and thickness inspections. After the first round of inspections is complete, scheduling of continuing inspections is dependent upon the results of this initial inspection.

INITIAL VESSEL INSPECTION

External Visual Inspection

An external visual inspection is performed for each pressure vessel. This inspection includes development of a hand sketch of the external condition of the vessel along with a rubbing of the nameplate if this has not been previously done. The sketch should be very thorough in detail including noting the flange size and rating of all flanges, any flanges which are blinded or which have normally closed valves, indications of surface irregularities such as blistering or peeling paint, rust, prior hardness or ultrasonic thickness test locations, leaking flanges, bulges, dents and dings. The thickness and diameter of all reinforcing pads should also be noted on the drawing.

The external visual inspection serves two purposes: 1) documentation of physical features of the vessel and 2) an indication of possible problems which might require the prioritization of the external thickness examination of the vessel be changed. As an example, a vessel may have a complete historical file which includes U1A report, original construction drawings, prior operating history and prior inspection history; however, if operating conditions have changed causing severe thermal cycling of the vessel, an external visual examination may indicate that paint deterioration has occurred rapidly. This should be an indicator of possible integrity problems elsewhere.

External Thickness Inspection

Documentation of the mechanical integrity of a pressure vessel includes determination of the remaining wall thickness of the vessel. For vessels which have no nameplate or other source of original wall thickness information, this is important to determine if the vessel was manufactured from steel of adequate thickness to contain the operating pressure. A second part of this mechanical integrity documentation is to determine if a pressure vessel has suffered from corrosion, erosion or other forms of damage which would compromise the pressure containing ability of the vessel.

There are no right or wrong inspection guidelines which can be used for every vessel. The inspection points for thickness determination should be chosen to represent the general nature of the vessel and also be indicative of any possible damage areas. Points should be chosen to document the integrity of each shell plate. Points in the water containing area along with ones in the gas phase and ones located to span any fluid/fluid or fluid/gas interfaces should be chosen. A few points should be chosen opposite of inlet nozzles and near outlet nozzles. These points should be reviewed to insure that potential corrosion or erosion points are investigated. At least one point must be examined on the neck of each nozzle to determine the wall thickness of the nozzle pipe pup or integral flange. This is probably one of the most critical points to examine should you be required to perform pressure vessel calculations to determine pressure containment ability since the limiting feature for most pressure vessels is the wall thickness of the nozzles.

Any areas on the outside of the vessel which were noted during the external visual examination as possible problem areas should be checked. Places which show severe paint cracking or rust exfoliation should be checked. It may be necessary to use more elaborate techniques such as shear wave ultrasonic thickness testing if blisters are found.

Mechanical Integrity Analysis

Once external visual and ultrasonic thickness inspections have been performed, the data must be reviewed to determine if further testing is warranted and if the vessel is fit for continued service. This analysis can be fairly easy or extremely complicated depending upon the amount of prior knowledge about the vessel and the results of the inspections. If the vessel has a nameplate with a corrosion allowance noted on it, or if a copy of the original U1A report is available, comparison of the present results to the original wall thicknesses is simple. If the vessel shows no corrosion or if the corrosion does not exceed the original corrosion allowance, the vessel can be immediately placed on a continuing examination list with the length of time before the next inspection based upon the amount of corrosion allowance left and the calculated corrosion rate. Depending upon the class of facility the vessel is on, the inspection period may be the maximum allowable for that facility class or one half the remaining safe operating life (RSOL) of the vessel. The RSOL is calculated form the following formula:

$$RSOL = \frac{t_{actual} - t_{minimum}}{\text{Corrosion Rate (inches/yr).}}$$

A vessel which has lost enough wall thickness through corrosion or erosion to use the entire corrosion allowance will require pressure vessel calculations to determine the Maximum Allowable Working Pressure (MAWP). A vessel with no corrosion allowance noted on the nameplate or no nameplate at all will also require MAWP calculations. These calculations can be done by hand or using one of many commercially available calculation programs on the market today. Initially, the vessel should be evaluated using the present code; however, if the vessel has a nameplate with a construction date, further calculations can be performed using the original code.

One of the trickier analyses is the determination of the minimum wall thickness to use in the calculations. Per API 510 section 3.7, the minimum thickness can be determined by gauging the minimum thickness of uncorroded surfaces or it may be determined by averaging the thickness over a generally corroded area. For vessels with inside diameters less than or equal to 60 inches, the minimum thickness is the average thickness along a line one half the vessel diameter or 20 inches, whichever is less. For those over 60 inches in diameter, the thickness is averaged over one third of the vessel diameter or 40 inches, whichever is less. When the vessel is corroded and has pitting, the pits may be disregarded if the following conditions are met: 1) no pit is greater in depth than 1/2 the vessel wall thickness exclusive of corrosion allowance and 2) the total area of the pits does not exceed 7 square inches within any 8 inch diameter circle, and 3) the sum of their dimensions along any straight line within the circle does not exceed 2 inches. An alternate method can be utilized by determining the minimum thickness for pressure containment of individual components using Appendix 4 of Section VIII, Division 2 of the ASME Code.

CONTINUING INSPECTIONS

Prioritization

Once the original vessel inspections and analyses are complete, each vessel can be placed on a continuing examination list based upon the results of the first inspection and the risk associated with continued operation of the vessel. Per API 510 Section 6, each owner-user shall have an inspection program which will assure that the vessels have sufficient structural integrity for normal service without any undue expectation of endangering the public. Any appropriate engineering, inspection and documentation programs may be used within the context of this program. ARCO has chosen to set the length of time between the external visual and ultrasonic thickness inspections based upon the risk classification of the facility and the individual vessel risk assessment.

Vessels which are in OSHA 1910.119 covered facilities or non-OSHA Class A facilities have external visual inspections performed every 5 years. The vessels also have external ultrasonic thickness examinations performed every 10 year or one half the Remaining Safe Operating Life (RSOL).

Vessels which are on non-OSHA 1910.119 Class B and C facilities have external visual inspection performed every 10 years. Individual vessels on Class B facilities have external ultrasonic thickness examinations performed every 15 years or 1/2 the RSOL while individual vessels on Class C facilities and common class of service vessels on both B and C Class facilities have external ultrasonic inspection performed every 20 years or 1/2 the RSOL. One stipulation on common class of service vessels is that a minimum number of vessels should be examined during each five year period. The sample size chosen is dependent upon the total number of vessels within that common class.

External Visual Inspection

The continuing external visual inspection involves comparing the original visual inspection drawing with the present condition of the vessel to determine if any changes have occurred with would affect the safe operation of the vessel. While the obvious review of the vessel is important, it is also important to note any change in the surrounding area such as new vessels being set which would change the vessel risk assessment due to spacing arrangements. Also care must be taken to insure that all physical changes to the vessel such as dents, dings and bulges are noted.

External Thickness Inspection

The continuing external thickness inspection does not have to completely repeat the original thickness inspection. A number of points should be picked from the original survey. These points should include a representative sampling of both corroded and uncorroded areas on the vessel. The worst corroded areas should definitely be rechecked but it is important to check a few areas where no corrosion was originally found. Depending upon the initial condition of the vessel, as few as five or as many as 100 points might be identified as continuing examination points.

The individual thickness readings for each point should be compared, in some manner, with the original (or last) inspection data. The greatest thickness change should be used for the corrosion rate determination. It is important to note that the corrosion rate for the inspection period <u>should not</u> be calculated using the minimum thickness readings from two different inspection points. This will generally result in a corrosion rate which is lower than the corrosion rate which is calculated based upon the point with the greatest wall thickness change. This becomes especially important when a vessel is approaching the end of its rated life and the calculation of inspection intervals is one half the ratio of remaining corrosion allowance to corrosion rate ($t_{(actual)}-t_{(minimum)}/CR$).

Documentation

A file should be prepared for each vessel or common class of vessels. This file should include a rubbing of the nameplate(s) along with a copy of this rubbing, an initial external visual inspection sheet, a copy of this external inspection with the external ultrasonic inspection points marked, and copies of any original documentation from the manufacturer. The manufacturer's documentation may include original design calculations, a U1A report, and R1 reports, construction or as-built drawings, copies of mill certification reports for the materials, and non-destructive test reports. Anything which can be found about the vessel should be placed in this file.

If a U1A report is not presently with the vessel file, the original manufacturer or National Board should be contacted to obtain a copy. If a copy cannot be secured in this manner, the nameplate rubbing becomes more important. For vessels with a nameplate, the stated nominal wall thickness can be checked against the measured wall and calculations performed to find the corrosion allowance if necessary. Vessels with no nameplate or U1A report will require a complete analysis of the design with all assumptions stated. It is important that the types of information typically found on a U1A report be determined and if necessary, an "alternate U1A" report developed with the actual measured data noted. This alternate report should very specifically state that the wall thicknesses, etc. are either measured or assumed. Under no condition, should a copy of the U1A report shown in the ASME code book be filled out and placed in the file as the original.

Once a vessel file is established, it should be updated with all inspection results, both external and internal. Any changes in the fluid stream or operating conditions should be documented, dated, signed and placed in this file. It is extremely important that all data sheets are signed and dated, with the name printed if the signature is illegible. This file becomes the audit point should OSHA ever request proof of inspection compliance and also is extremely useful when evaluating processing condition changes since all data concerning this individual vessels resides in one place.

Table 1
Facility Risk Assessment

- **Energy Level (Normal Operating Pressure)**
  - Gas < 125 psig or liquid — 0
  - Gas > 125 psig or flashing liquid — 1
  - Gas > 700 psig — 2
  - Steam — 1

  Total _______

- **Flammability**
  - Non-flammable — 0
  - Low flammability liquids (Crude oil, diesel, etc.) — 1
  - High flammability liquids (NGL/LPG, condensate, gasoline, etc.) — 2
  - Flammable Gas (lighter than air) — 1
  - Flammable Gas (heavier than air) — 2

  Total _______

- **Toxicity/Asphyxiants**
  - Non-toxic — 0
  - H_2S < 300 ppm (See Note #1) — 1
  - H_2S > 300 ppm (See Note #1) — 2
  - Heavier than air gas such as CO_2 — 2

  Total _______

- **Exposure**
  - Unmanned and low public exposure — 0
  - Manned 8 hours/day and/or frequent public exposure — 2
  - manned 24 hours/day and/or constant public exposure — 3

  Total _______

- **Environment**
  - Fluid release non-damaging (Fresh water, etc.) — 0
  - Fluid release Minimal Impact (Release limited by system) — 1
  - Fluid release severe impact (Release not limited by system) — 3

  Total _______

- **Economic Consequence**
  - Low potential loss of capital equipment, revenue and good will at this facility — 0
  - Medium potential loss of capital equipment, revenue and good will at this facility — 1
  - High potential loss of capital equipment, revenue and good will at this facility — 3

  Total _______

- **Equipment Spacing**
  - Ample spacing is/will be provided — 0
  - Spacing is marginal — 1
  - Spacing is very tight — 2

  Total _______

- Other factors
  - User may enter a value here, ranging from 1 to 3, to account for hazards unique to a particular process, (i.e., sulfanol, vibration, etc.) or extreme public exposure ____

TOTAL ________

Note #1 H_2S based upon highest anticipated concentration in the process

Facility Risk Assessment Scoring

- Total is 11 or more - **Class A Facility** Risk factor = 1.5
- Total is 6 to 10 - **Class B Facility** Risk factor = 1.3
- Total is 5 or less - **Class C Facility** Risk factor = 1.0

Table 2
Pressure Vessel Inventory Checklist

Lease or Facility ____

Vessel Location (Tank farm, well site, gas plant, etc.) ______________________________

Vessel Identification number ____

Manufacturer ____

Date Manufactured ____

Manufacturer's Serial number _______________ National Board Number __________

Vessel has nameplate? Yes / No

Horizontal ___ Vertical ____ Insulated Yes / No Vessel Size _________________

ASME API stamp? Yes / No

RT , RT-1 , SR (circle one if present)

Shell wall thickness _________ Head wall thickness ________ Head Knuckle Wall Thickness _______

Shell Corrosion Allowance ___________ Head Corrosion Allowance ___________

Maximum Allowable Operating Pressure __________ Design Temperature ___________

Operating Pressure ______________ Operating Temperature __________

Contents (Crude, water, 3 phase, glycol, etc.) ___________________________

Number of pressure safety valves _______ Settings__________________

Table 3
Pressure Vessel Risk Assessment

	Sour			Non-Sour			Selected Rating
Corrosive	None	Mild	High	None	Mild	High	
• **Operating Pressure**							
$\leq$ 0 psig (not designed for vacuum)	2	4	6	6	7	8	
> 0 & < 125 psig	0	0	0	0	0	0	
>125 & < 500 psig	1	2	3	3	4	5	
> 500 & < 1000 psig	2	4	6	6	7	8	
> 1000 psig	3	5	7	7	9	10	___
• **Operating Pressure Level**							
< 80% nameplate MAWP	0	0	0	0	0	0	
> 80% nameplate MAWP	5	6	7	8	9	10	___
• **Age of Vessel**							
Code PV, $\leq$ 10 years	0	2	3	3	4	5	
Code PV, >10 years & < 20 years	1	3	5	5	6	7	
Undocumented PV $\leq$ 10 years	2	3	4	4	5	6	
Undocumented PV .> 10 yrs & < 20 yrs	3	4	6	6	7	8	
> 30 years	4	5	7	8	9	10	___
• **Over-heat or cold fracture potential**							
Unfired or indirect fired	0	0	0	0	0	0	
Direct fired	1	2	3	4	5	6	
Steam Heated	0	1	2	3	4	5	
Heat Medium/Oil Heated	0	1	2	2	3	4	
Cryogenic	0	1	2	2	3	4	___
• **Nameplate status**							
Readable	0	0	0	0	0	0	
Missing/unreadable & vacuum condition	5	7	9	9	11	13	
Missing/unreadable & oper. 0 - 125 psig	1	2	3	3	4	5	
Missing/unreadable & oper. 125-500 psig	3	4	5	5	7	9	
Missing/unreadable & oper. 500-1000 psig	5	7	9	9	11	13	
Missing/unreadable & oper. $\geq$ 1000 psig	7	9	11	11	13	15	___
• **Repair status/patches**							
Flush patch(es), R-1 available	0	0	0	0	0	0	
Flush patch(es), R-1 not available	1	2	3	3	4	5	
Lap Patch(es)	3	5	7	8	9	10	___
• **Bulge(s)**							
None	0	0	0	0	0	0	
1 or more	5	5	5	10	10	10	___
• **External Pitting**							
None	0	0	0	0	0	0	
Moderate	1	2	3	3	4	5	
Severe	2	3	5	5	7	9	___
• **Bent Nozzle**							
None	0	0	0	0	0	0	
1 or more	3	3	3	5	5	5	___
• **Structural Stability**							
Stable	0	0	0	0	0	0	
Unstable	8	8	8	10	10	10	___

SUM OF ALL 10 BOXES = PRESSURE VESSEL RISK FACTOR ...._____