PETROLEUM PRODUCTION ENGINEERING
BITS AND PIECES

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Before exiting the oil patch, I want to provide a partial list of the tools that helped me anticipate, find, define and suggest solutions to petroleum production problems. Educators tell us that if we can fully define a problem, the solution usually becomes readily apparent.

PRODUCTION FACILITY PRESSURE VESSELS

1. Relief valves on all pressure vessels should be installed so that the pressure drop between the vessel exit and the relief valve does not exceed three percent of the set pressure. This will allow a blowdown of five percent of set pressure. If the friction pressure drop exceeds blowdown, the relief valve will chatter when activated and this will destroy the seat.

2. Relief valves should be installed upstream of wire mesh mist extractors and pressure taps should be installed up and downstream of all mist extractors to detect plugging, etc.

3. Relief valves cannot be reset in the field for more or less than ten percent of factory set pressure if the set pressure is 275 PSI or less. Set pressures cannot be changed more than five percent if the set pressure is above 275 PSI.

4. Relief valves should be reset by authorized companies or personnel when an inspection indicates that the maximum allowable working pressure of the vessel has been decreased by corrosion, modification, etc.

5. Relief valve gas vent lines should terminate not less than twelve feet above grade and these lines must not contain liquid traps.

6. All vessel exits, except in slurry service, should be equipped with vortex breakers.

7. A very small negative pressure will collapse a tank or pressure vessel. Therefore a vent valve should be opened when a drain valve is opened.

Recommended vent valve size versus drain valve size for different vessel capacities are:

Volume of Vessel, $Ft.^3$	Nominal Vent Size, In.	Nominal Drain Size, In.
Up to 200	1.5	1.5
200 to 600	1.5	2.0
600 to 2500	2	3
Over 2500	3	4

8. Valves and fittings that depend on elastomer seals should not be utilized on or near fired vessels.

9. Firebox flame arrestors should be maintained and tested in accordance with A.P.I. RP12N published in January 1986.

10. Bottoms should be drained off of all vessels automatically. Do not depend on the human element.

11. Gas-liquid separators are usually not required upstream from modern emulsion treaters.

12. Free water knockouts upstream from fired emulsion treaters should allow some water to enter the treater, because fire tube holes will occur. If little water enters the vessel, oil will flow out of the hole and a fire could result. A one-eighth inch diameter hole in a fire tube will leak about 73 barrels of water per day if the pressure in the water bath is 30 PSIG.

PRODUCTION FACILITY TANKS

1. Reliable gas blankets require an outside source of gas.

2. About twelve inches of water will float an empty tank. Dike height should be limited. Dikes double the required emergency gas venting capacity.

3. Tanks should be placed on foundations that will enable the operator to check for tank bottom leaks.

4. Bolted tank deck leaks should be repaired before the construction crew leaves the facility.

5. Spring actuated thief hatches equipped with envelope gaskets are recommended. Some Viton gaskets give satisfactory service in hydrogen sulfide areas.

6. Tank battery gas vent lines should slope up at about one-quarter inch per foot to an in line pressure-vacuum vent valve and should slope down from this valve to the exit. There must not be any liquid traps in this line.

7. Tank overflow lines should be equipped with pee traps that will hold a back pressure equal to one hundred and fifty percent of maximum allowable tank vapor space pressure, when the trap is filled with fresh water.

8. Overflow lines from oil-water gravity separators should overflow water while allowing oil to be stored in the vessel. The bottom of the overflow exit should be equipped with a vortex breaker.

9. Pipeline oil should enter storage tanks or L.A.C.T. run tanks through a vented downcomer that terminates one foot from the tank bottom. The vents should be at least two-one half inch holes just below the tank deck. The optimum downcomer area in square inches will be greater than 0.01872 x maximum inflow, barrels per day. This will allow large gas bubbles to escape through the vent holes and not roll the tank.

10. Carbon steel vessels in corrosive water service should be plastic coated "Holiday Free" and cathodically protected with sacrificial anode. Holidays will be created during installation, when cleaning the vessel, etc.

11. A frangible deck-shell weld can eliminate the need for multiple thief hatches on hydrocarbon storage tanks.

12. All steel tanks should be attached to permanent, reliable grounds. The only permanent ground, onshore, is well casing that penetrates permanent moisture.

13. The National Fire Protection Association No. 78, "Lightning Protection Code", teaches that an air terminal's cone of protection has a diameter equal to twice the height of the air terminal. The code also states that steel tank decks thicker than three sixteenths of an inch will not be penetrated by lightning strikes. It is recommended that tanks with thinner decks and tanks constructed of other materials be protected with air terminals.

14. Vessels and piping that are not in service should be removed from the producing facility. Bacteria breeds in dead spaces.

15. To separate a three phase fluid stream:

    a. Separate the large gas bubbles from the liquid.
    b. Introduce the liquid stream, which contains small bubbles, into the gravity separation chamber under a saw-toothed spreader that is vented into the vapor space.
    c. If the major objective is to clean up the water, the liquid should enter far from the water exit and just below the oil-water interface.

d. If the major objective is to clean up the oil, the liquid should enter far from the oil exit and below the oil-water interface.
e. Oil-water separator capacity is proportional to oil-water interface area.

16. Emulsion blankets build up in low temperature oil-water treating systems. Provisions should be made to monitor the build up and to break it down into oil, water and solids on a regular schedule.

17. If the water bath temperature in a wash tank is greater than the boiling point of the water bath minus 40°F, (above 170°F near sea level) thermal currents and a boiling action occur. This will disrupt gravity separation of oil and water.

PRODUCTION PIPING

1. If plastic or fiber reinforced plastic piping could be subjected to bursting pressure, it should be buried. It fails like a hand grenade when it bursts. The bursting pressure, the tension loads that will cause failure, etc. decreases with time. Sunlight can cause early failure. If this pipe is exposed to sunlight, it should be painted.

2. Water hammer can cause bursting failures in any piping system. In steel pipe water hammer pressure increases can approach 60 PSI per foot per second instantaneous decrease in velocity. For example, if a velocity decrease of 10 feet per second occurs, a pressure increase of 600 PSI could be measured upstream from the activated valve. Air chambers upstream from the valve can decrease the pressure and this is the solution in your home, but is usually impractical in producing systems. Practical solutions include closing the valve very slowly and keeping all valves out of systems where closing the valve could cause a catastropic failure.

3. Don't put straight pipe between to fixed points. If the yield strength of line pipe is 36,000 PSI, a temperature decrease of less than 180°F can cause the pipe to yield and an increase of less than 180°F can cause the pipe to collapse. ANSI B31.3 tells us that a stress analysis should be made if the following approximate criterion is not satisfied: Nominal pipe diameter , inches, times expansion to be absorbed by the pipe divided by (actual length of pipe, ft. minus straight line distance between anchors, ft.) squared must equal, or be less than, 0.03. Here is a problem. Given:

   Maximum difference between atmospheric temperature and operating temperature will be 200°F.

Nominal pipe diameter, D, is 6 inches.

Distance between anchors, U, is 50 feet.

Assume:
Coefficient of thermal expansion is 7×10^{-6} inches per inch per degree F for carbon steel pipe.

Find:
The amount of pipe, L, that should be placed between the anchors.

Solution:
a. Assume L, actual length of pipe = 64 ft.

$$D \times L \times 12 \times 7 \times 10^{-6} \times T/(L-U)^2 = \_\_\_\_\_\_\_\_$$

$$6 \times 64 \times 12 \times 7 \times 10^{-6} \times 200/(64-50)^2 = 0.0329$$

Note: This is greater than 0.03

b. Assume actual length of pipe, L = 65 ft.

$6 \times 65 \times 12 \times 7 \times 10^{-6} \times 200/225 = 0.0291$, so installing 65 ft. of pipe between the anchors will not necessitate a stress analysis.

4. Many piping systems and well annuli should be equipped with relief valves. Temperature increases can cause pressure increases in closed piping systems that can rupture the pipe and these increases in annuli can collapse the inner pipe.

5. Assume that all valves leak. If a well must be positively shut-in, part the exit pipes and install bull plugs or blind flanges. If a vessel, pump, etc. must be isolated, part the entering and exit piping and install plugs or blinds. Block and bleed valves should be used to detect small leaks in by-passes, etc.

6. Water piping should be buried below the frost line. The frost line in Lubbock, Texas, is about 12 inches below the surface. The lowest recorded atmospheric temperature at Lubbock has been -17°F. Buried steel piping should be coated and wrapped and cathodically protected.

7. Water legs on gravity settling tanks should be sized to be self venting. If the inside diameter, or the equivalent diameter in inches, is greater than 0.92 times the flow in gallons per minute to the 0.4 power the downcomer will be self venting. In other words, flow will not entrain

vapors. Some artificial lift wells equipped with sucker rods have to be hot oiled to remove the paraffin from the tubing. If the hot oil is pumped down the casing-tubing annulus, the pump has to be in operation to insure that the melted paraffin is pumped out of the tubing. If the hot oil rate is too high, a slug of hot oil will compress the gas in the casing-tubing annulus and drive the liquid in the annulus back into the formation. This will starve the pump and the resulting liquid pound will damage the pumping equipment. Here is an example:

Given:

A well equipped with 5.5 in. O. D., 15 lb./ft. casing and 2.875 in. O. D. tubing has to be hot oiled down the casing-tubing annulus.

Find:

Maximum allowable hot oil rate, GPM.

Solution:

Area of the 5.5 in. - 2.875 in. annulus is 12.95 in.^{2}.
The equivalent diameter is = 4.06 in.

Since this diameter, d, must be greater than 0.92 $Q^{0.4}$, Q must be less than $(d/0.92)^{2.5}$ or less than 40.9 gallons per minute.

8. Elastomer gaskets should not be used if the operating pressure of a piping system, PSIA, times the operating temperature, ^oF, exceeds 250,000. **Example problem:** If T = 300^oF, use metallic gaskets, if operating pressure is equal to, or greater than, 250,000/300 = 833 PSIA.

9. Temporary strainers for use in 2 inch through 10 inch nominal pipe shall have basket open area of not less than 200 percent of the cross section flow area. The flow area should be 150 percent or more in larger pipe. The basket should point upstream. Permanent strainers should have an open area equal to at least four times the flow area.

10. A piping system will not make excessive noise if the piping velocity head is less than 1.3 PSI. This is achieved if the velocity, ft./sec., is kept below 110 divided by the square root of the density of the flow stream, lbs./ft.^{3}. Recall that API RP14E, the A.P.I. "Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems", Fourth Edition, recommended that this constant be 100 to control erosion.

11. Gravity drainage lines should slope downward enough to cause the velocity to equal 3 feet per second with fresh water flowing. This velocity can keep the line clean. The required

slope is about 0.56 in. per ft. for a 1 in. nominal, schedule 40 steel line and a slope of 0.25 in. per ft. for 2 in. nominal, schedule 40 steel pipe.

12. Liquid lines that change elevation should be liquid packed at start-up.

13. Pipe schedule number is approximately equal to 1000 times operating pressure, PSIG, divided by allowable stress, PSI.
    Example problem:
    Find:
    The required schedule for ASTM A106 grade B steel pipe operating at 1200 PSIG and 600°F.

    Given: The allowable stress for this pipe is 15,000 PSI.

    Solution:
    Schedule No. = 1000 x 1200/15000 = 80.

14. Don't allow well service crews, drilling crews or pipeline crews to apply thread dope with a swab to the female threads of casing, tubing or line pipe, especially in water injection or disposal systems.

15. Do not allow non-upset tubing to be run into wells that will be artificially lifted with reciprocating sucker rods. The threads on non-upset tubing weaken the tube and just a little sucker rod coupling wear will cause the tubing to part.

16. Every length of tubing, casing and liner run into a well should be drifted.

17. Torque has been completely discredited for properly making up API threaded connections.

18. Return pipe bends in indirect heaters should be safety drilled with 1/16" to 3/16", 60°, tapered drills. The drill should penetrate 50 percent plus or minus 0.015" of the nominal wall thickness.

19. Oversized control valves, check valves, dump valves, etc. will have a short life.

20. Three washout plates should be placed on all pipes that penetrate dikes.

21. Threaded pipe in vibrating service should be made up dry and seal welded.

ARTIFICIAL LIFT

1. When an oil well dies, consider installing artificial lift. Money spent swabbing dead wells is often money down the drain. If pressure maintenance or water-flooding is in progress, reservoir pressure could be increased enough to return the well to flowing status, but wishful thinking will not cause it to flow. In most cases, artificial lift will increase production from flowing wells, if the casing is large enough to allow near optimum subsurface equipment to be installed. For example, a subsurface electric pump was utilized in North Africa in the 1960's to increase a well's production from 5000 to 12000 barrels of oil per day.

2. Gas lift is an excellent interim artificial lift method. Gas lift gas supplements the reservoir gas. As water cut increases and as the gas-liquid ratio decreases, the gas lift system will become less efficient than some other artificial lift methods. Gas lift usually cannot reduce producing bottomhole pressure as much as some other methods. If the casing is too small, and if you have to lift several thousand barrels of liquid per day from each well most any casing is too small, gas lift can be the only practical choice. Gas lift may be the only practical choice because of space limitations offshore.

3. Walking beam activated sucker rod pumps are the most idiot proof artificial lift method devised by man to date. The optimum sucker rod installation will have an electric motor prime mover, the well capacity with the producing BHP at, or just below, 10 percent of shut-in reservoir pressure will be between 65 and 85 percent of calculated pump displacement. The well will be equipped with a pump-off control. The lease operator will be sold on P.O.C.'s and he will be trained to operate them. If this has not been done, do not waste your money buying P.O.C.'s. The recommendation to design the installation to have a pump displacement greater than well capacity does not apply if fiberglass reinforced plastic sucker rods are utilized because these rods will be damaged by the compressive load that results from the fluid pounds that will occur if pump displacement exceeds well capacity. Sand production usually prohibits time clocking and P.O.C.'s.

4. Assume that all produced fluids are corrosive and do not allow oxygen to enter the system, especially if the produced fluids contain carbon dioxide and/or hydrogen sulfide because no economical corrosion inhibitor is available. An effective and economical corrosion inhibitor:

   a. Will not require more than 25 parts per million.
   b. Will not cause an emulsion to form when mixed with produced fluid.
   c. Will be water dispersible and oil soluble, and
   d. Will keep corrosion below 0.005 inches per year while prohibiting pitting corrosion.

Do not take just anyone's word for what a corrosion inhibitor will do, pay an independent laboratory to test the inhibitor. Free laboratory work is usually worth less than it costs you. Oxygen does enter the well during the installation of artificial lift equipment, during servicing, etc., so be sure that all of the subsurface equipment is coated with inhibitor at start-up. You should also consider filling the tubing with liquid before start-up if the artificial lift equipment utilizes sucker rods or centrifugal pumps. In dry tubing sucker rod coupling-on-tubing wear is very high and centrifugal pumps experience excessive up thrust wear when required discharge head is low. Low discharge head can cause required input horsepower to exceed the capacity of the prime mover with some centrifugal pumps.

5. Do not lift a corrosive liquid from above the top of the cement behind the oil string. Batch corrosion inhibitor treatments can just protect the casing interior from the surface to the pump intake perforations. The only way all of the casing interior can be protected is to have the pump intake below the producing zone. This may not be practical or possible if economics will not justify the purchasing of larger artificial lift equipment or if casing has not been set through the pay zone and drilled out.

6. a. A gassy well can be lifted most efficiently with positive displacement pumps if the pump intake is below the pay zone.

   b. If the well is making mostly water, assume the liquid capacity of this "natural gas anchor" will be approximately equal to the area of the casing-tubing annulus in square inches times 53. This assumes that large gas bubbles can rise at 6 inches per second. If the well is making almost 100 percent oil, the bubble rise velocity will be decreased and the natural gas anchor liquid capacity will drop. I assume that the viscous liquid capacity is equal to the water capacity divided by the viscosity in centipoises to the 0.25 power.

   Example problem:

   Given:

   A well has a 5.5 in. O.D., 15.5 lb./ft. x 2.375 in. annulus and will produce 15 cp oil before water break through.

   Find:

   Natural gas anchor liquid capacity when well is producing oil and capacity after water cut increases enough for system to become "water wet".

   Solution:

   1. Area of annulus = 0.1029 ft.^{2} x 144 in.^{2}/ft.^{2} = 14.8176 in.^{2}.
   2. Natural gas anchor water capacity = 14.8176 x 53 = <u>791 BWPD</u>.

3. Estimated capacity if liquid to be pumped has a viscosity of 15 centipoises = $791/(15)^{0.25} = 791/1.97 =$ 402 BOPD.

c. I think natural gas anchors are limited capacity vertical gas-liquid separators. For five foot vertical separators the A.P.I. 12J separator spec. empirical formula estimates gas rise velocity to be between 0.12 and 0.24 ft./sec. times (density of the liquid minus the density of the gas divided by the density of the gas) to the 0.5 power. The densities are in lbs./ft.^{3}.

Example problem:

Given:

A gassy well has an annulus area of 0.1029 ft.^{2}

Assume:

A gas rise velocity can be = $0.18((D_l-D_g)/D_g)^{0.5}$; D_l = 60 lbs./ft.^{3}; D_g = 0.5 lbs./ft.^{3}; intake pressure = 100 PSIA; intake temperature = 130^{o}F. Estimate gas separation capacity in standard cubic feet per day.

Solution:

1. Gas rise velocity = $0.18((60-0.5)/0.5)^{0.5}$ = 0.18 x 10.91 = 1.96 ft./sec.
2. Capacity, actual ft.^{3}/day = 1.96 ft./sec. x 0.1029 ft.^{2} x 86400 sec./day = 17457 ft.^{3}/day; capacity, standard ft.^{3}/day = 17457 x 100/14.7 x (460+60)/(460+130) = 104,667 standard ft.^{3}/day.

Note that this is a little over 7000 standard ft.^{3}/day per square inch of annulus area. If this is correct, justification exists for not running 4.5 in. or even 5.5 in. casing in high volume wells when the gas-liquid ratio will exceed 100 to 200 ft.^{3}/bbl.

7. On beam pumping installations:

a. Always screw a plugged polished rod coupling on to the top of the polished rod.

b. Replace the brass follower in the bottom of the polished rod stuffing box when it wears out-of-round more than 0.05 inches. It probably wore because the unit is not "setting over the well".

c. The amount of unanchored tubing above a reciprocating sucker rod pump that buckles on the up-stroke is equal to the transferred load in pounds divided by 4.1, 5.7 or 8.1 respectively for 2, 2.5 or 3 inch nominal tubing. Buckling can be eliminated with tension tubing anchors. If anchors are not run, the buckled tubing should be moved to the top of the string when the tubing is pulled.

d. If the produced fluid contains gas, be sure the valve rod or pull tube in insert pumps is cut so that valves are a maximum of one half inch apart at the end of the downstroke.
e. Fluid pounds can cause threaded connections to leak. Do not time clock a well or install a pump off control if there are collar leaks or tubing leaks. Temperature and pressure cycling can also cause collar leaks in all threaded connections.
f. I cannot recommend "75" or "85" sucker rod strings. Rods in the seven eighths or one inch rods will fail and the large rods falling on the five eighths rods will junk them. A one-quarter inch bend in five feet is permanent damage and will cause a failure in a heavily loaded string.
g. Tapered tubing strings, as well as tapered rod strings are recommended in deep wells. This decreases investment, supports the small rods in the bottom sections and increases the size of the "natural gas anchor". It will be easier to unseat a pump from a 2 inch nominal seating nipple than from a 2.5 inch nominal seating nipple.
h. The maximum instantaneous inflow rate is approximately pump displacement, BPD x 3.1416. This tells me that we should design natural gas anchors and poor boy gas anchors to store 1.5 to 2 pump displacements, in cubic inches, above the natural gas anchor strainer nipple and above the opening in the poor boy gas anchor dip tube.

8. Electric Submergible Pumps:
   a. The only way that you can assure that liquid flows by the motor that is below the pump at all times at a velocity of one foot per second is to install a shroud or a packer.
   b. At this time we do not have an allowable vibration standard for ESPS pumps and motors. An API task group is studying this problem.
   c. Always install a vent box between the well head and the control box.
   d. Large ESPS are more efficient than small ones. Considering the ever increasing cost of electricity, this can justify the installation of larger casing.
   e. First class grounding systems and lightning protection are recommended.

SURFACE PUMPS

1. Reciprocating water pumps should be set not more than eight feet from the suction tank. Low water level should be at least eight feet above the pump suction flange. The pipe from the tank to the pump should be at least one size larger than the suction flange and the line size should be reduced with an eccentric reducer, belly down. The line should slope up from the tank to the pump. Elevation changes should be made with 45 degree ells.

2. If the pump is handling gas saturated water from pressure heater-treaters, free water knockouts, etc., it should pass through a gas boot before it enters the suction tank. It should enter the suction tank under a vented, saw toothed spreader. If this is not done, the gas that is released from the water will roll the tank.

3. The pump plungers should have a 16 microinch RMS finish. The inside of the packing box should have a 63 microinch RMS finish.

4. All positive displacement pumps should have a relief valve in the discharge piping. There should be no isolating valves between single relief valves and the pressure source. The relief valve should never discharge into the pump suction pipe. Multiple relief valves can be equipped with locked open-locked closed isolating valves, but this usually causes excessive friction pressure losses.

5. Suction pulsation dampners can compensate for poorly designed suction piping.

6. Discharge pulsation dampners can decrease piping failures and increase meter accuracy. Do not consider bladder pulsation dampners that cannot be precharged to 70 percent of discharge pressure.

7. The Hydraulic Institute specifies how net positive suction head required, NPSHR, will be determined for a centrifugal pump. This NPSHR results in a 3 percent loss in discharge head. Cavitation damage occurs in the pump before discharge head starts to decrease. The reciprocating pump manufacturers tell the user that the NPSHR results in a decrease in discharge rate of 3 percent. Cavitation damage occurs in these pumps before discharge rate starts to decrease. It is recommended that users ask manufacturers to supply 3 NPSHR curves on important pumps.

    a. A NPSHR that results in a 3 percent loss in discharge head for centrifigal pumps or a 3 percent loss in discharge rate for reciprocating pumps.
    b. NPSHR for no loss in discharge head or rate.
    c. NPSHR to prevent cavitation.

   The user will find that it is impractical to supply the NPSHR for no cavitation except on very important pumps. On these pumps a sacrificial charge pump between the suction tank and the important pump can be the answer.

8. Back-up pumps are not recommended. If a back-up pump is "on location", it can serve as a source for spare parts and, if this occurs, it will not be available when needed. If a back-up pump is available, preventive maintenance may be neglected on the operating pump. Do not ever make it easy for people to not do a good job.

MISCELLANEOUS

1. There must be an isolating valve between a pressure guage and the pressure source.

2. Do not design to use more than 60 percent of a pressure guage's capacity in pulsating service or more than 75 percent in steady pressure service.

3. Sulfate resistant cement should be used in foundations exposed to sulfate action.

4. Welding on anchor bolts can cause catastrophic failures.

5. If fuel gas contains hydrogen sulfide, the flue gas temperature should be maintained well above the dew point. This is about 290°F if the content is one percent and about 360°F if it is 10 percent.

6. Carbon dioxide will not cause a corrosion problem if the partial pressure,PP, is 7 PSI or less. It could cause a problem if PP is 7 to 30 PSI and it will cause a corrosion problem if the PP is 30 PSI or above.

7. Guard and maintain clean guage glasses.

8. Positive displacement meters in gravity metering systems are recommended if the liquid viscosity is above 5 cs. High viscosity drastically reduces the range of turbine meters.

9. Monitor the pressure up and downstream from temporary and permanent strainers. Do not use mesh smaller than one quarter inch in crude oil strainers. Design piping systems so that the temporary strainers can be easily removed and cleaned.

10. Hold a minimum of 10 PSIG on LACT samples. Do not paint the sample container black, be sure it is in the shade and be sure it is easy to clean and that it is cleaned on a regular schedule. Anytime an LACT sample contains free water the seller suffers a revenue loss.

11. When a new reservoir fluid sample is analyzed, determine the foaming tendency of the crude and find an efficient economical defoamer.

12. Gas stripping usually cannot decrease the oxygen content of salt water to 50 parts per billion. Therefore, the water will still be corrosive.

13. Do not allow plastic buckets to be used to secure crude oil or condensate samples, to divert leaks, etc. Static electricity will build-up until it jumps to a ground and a fire can result.

14. Do not allow two chemicals to be injected at the same point. Do not allow chemicals that cancel out the benefits of other chemicals that are being injected to be purchased. For example, chemicals that remove corrosion inhibitor films are available from the same supplier.

15. Steel is permeable to hydrogen atoms. If hydrogen sulfide corrosion occurs in a carbon steel system, hydrogen atoms are released and some flow into the steel. If they unite with another hydrogen atom or a carbon atom in a void space in the steel, molecules are formed, pressure builds up in the void space and if the steel is not ductile, hydrogen embrittlement failures can occur. This is why we should not allow hard carbon steels to be utilized in hydrogen sulfide systems. Hard carbon steels have a Rockwell C hardness greater than 23 and a tensile strength greater than 115,000 PSI. Acceptable steels are listed in N.A.C.E. MR0175-84, "Sulfide Stress Cracking Resistant Metallic Materials For Oilfield Equipment".

16. Plastic pipe is permeable to gas molecules. If plastic pipe is run inside of steel pipe that does not contain vent holes and if the fluid flowing inside the pipe contains gas, over time, gas will flow through the plastic pipe, collect in void spaces in the plastic pipe-steel pipe annulus and collapse the plastic pipe if the pressure inside of the plastic pipe is ever reduced.

17. Undersized, or partially plugged, flame arrestors can restrict air flow to the flame. If excess air is below about 20 percent all of the fuel will not be consumed. If all of the carbon in the fuel is not burned, carbon black can be deposited in the fire tube. This constitutes a safety hazard, because part of the carbon black will burn explosively whenever the burner is ignited because there will be excess oxygen in the fire tube at that time.

18. Oxygen scavengers will not remove oxygen from produced water if the water contains more than 50 parts per million hydrogen sulfide.

19. All 5 horsepower and above electric motors should be equipped with 120 volt space heaters in critical intermittent or critical stand by services.

20. Electric ground wires should be No. 4 bare copper wire, or larger. No. 4 wire has a diameter of 0.2043 inches. The wire should be attached to well casing with a thermite weld. If a clamp is used, the connection should be above ground because dissimilar metal corrosion will destroy the connection if it is buried. The bare wire should be attached to the equipment with a lug, not wound around a foundation bolt.

21. Upset tubing to be utilized in a carbon dioxide environment should be fully normalized after upsetting to control ring-worm corrosion.

22. In time, waterflood injection water will plug the formation and pressure parting will be required to secure economical oil production. Therefore, it is recommended that all waterflood injection system piping be designed to allow pressure parting.

23. It is recommended that crude oil be periodically skimmed from clear water tanks. If waterflood injection pumps try to inject oil, the required discharge pressure can be great enough to burst the discharge piping. This can cause the waterflood station to burn down.

REFERENCES AND CREDITS

My references include the text books from the Conoco Inc. school that I attended, Mechanical and Chemical Engineering Handbooks, API, ASME, ANSI, NFPA, ASTM, NACE and Hydraulic Institute Standards, Conoco Central Engineering Standards and SPE, API and SWPSC Papers.

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