Shut-In Procedures

WILD WELL CONTROL

Shut-in Procedures

Learning Objectives

- You will learn general shut-in procedures:
  - For surface BOPs.
  - For subsea BOPs.
  - Shut-in procedural differences.
  - Modifications to procedures based on activity.
- You will learn to interpret shut-in pressures and be able to perform related calculations.
- You will learn general gas theory.

Shut-in Procedures

Overview

- For wells that can be shut-in, procedures are basically the same.
- Minor differences in shut-in sequences vary by:
  - Company policies
  - Well conditions
  - Equipment
  - Position of equipment
  - Activity

Shutting the Well In

- Once a kick has been detected, the well must be shut in quickly for many reasons:
  - To keep the rig and crew safe.
  - Minimizes the kick and stop the influx of formation fluid into the wellbore.
  - Provides time to evaluate situation, record shut-in pressure and perform calculations.
  - Gives you time to organize the kill procedure.

Shutting the Well In

- Basically, once a kick has been detected:
  - String must be secured.
  - BOP must be closed.
  - Choke/kill manifold aligned.
  - Evaluate pressures.
  - Develop plan to kill/control well.
  - Regain control of well.

General Shut-in Procedure While On Bottom

- Stop rotating, sound alarm.
- Pick up off bottom.
  - Clear lower kelly valve/spacer sub.
  - Space out so tool joints will not be in ram.
- Stop pumps.
- Check for flow.
- Open valve/line from BOP stack outlet to choke manifold.

General Shut-in Procedure While On Bottom

- Close BOP. Ensure that choke is closed.
- Confirm that flow has stopped.
- Begin recording Shut-in Drill Pipe Pressure (SIDPP) and Shut-in Casing Pressure (SICP) at regular intervals (e.g., every minute).
- Record gain in pits.
- Notify Supervisor.

General Shut-in Procedure While Tripping

- Stop pipe movement, (tool joint at easy access level), set slips, sound alarm.
- With the valve in the *OPEN* position, install Full Opening Safety Valve (FOSV, sometimes called a “TIW” or “Safety Valve”). Once made up, *CLOSE* it.
- Check for flow.
- Close BOP.
- Open valve/line from BOP stack outlet to choke manifold.

General Shut-in Procedure While Tripping

- Ensure that choke is closed.
- Confirm that flow has stopped.
- Pick up and make up kelly, *OPEN* FOSV. On top drive units install pup joint or single for easier rig access.
- Begin recording Shut-in Drill Pipe Pressure (SIDPP) and Shut-in Casing Pressure (SICP) at regular intervals (e.g., every minute).
- Record gain in pits.
- Notify Supervisor.

Hang Off Procedure

- Conduct a space-out.
- Ensure that a TJ (tool joint) is not in the ram face.
  - On floating rigs it may be difficult to know exactly where the TJ is.
  - Monitor BOP flow meter and annular pressure regulator.
  - Slowly pull pipe until an increase is noted on the regulator (TJ passing through annular packer), then BOP flow meter should increase to close annular after TJ goes through.

Hang Off Procedure

- Once TJ spacing is known, close rams.
- Slowly lower string until TJ contacts ram. Observe Weight Indicator for decrease.
- Activate ram lock mechanism (if not automatic).

Shut-In Casing/Cementing

- Before casing is run:
  - BOPs should be equipped with casing rams and pressure tested before running casing. Annular Pressure regulator may have to be reduced to prevent casing collapse.
  - A circulating swage with a high pressure/low torque valve must be made up on cement head and positioned near the rotary table, installed as soon as the BOPS have closed.
  - There should be a crossover from the casing to the string on floating rigs to allow the string to be hung off if necessary.

Shut-In Casing/Cementing

- When shutting in using casing rams ensure TJ is not across ram face.
- Close BOP (casing ram or annular according to procedure).
- Install cement head.
  - Note: The inner diameter of the string is usually shut off first because it is the smallest and most vulnerable.
    - When casing is run, and in some slim hole and workover applications, the smaller diameter is often the annulus. In these cases, the annulus smallest diameter should be shut in first.

Hard vs Soft Shut In Procedures

- Depends on the choke position.
- Hard shut in usually preferable because:
  - Quicker, therefore minimizes kick volume.
  - Choke is closed preventing additional influx.
- Use proper Company Policy and Procedures.

Verification of Shut-In

- After well is shut in, these areas should be checked for leaks:
  - Check flow line.
  - Check manifolds.
  - Check lines to BOP stack.
  - Check BOP stack.
  - Check safety and kelly valves.
  - Monitor area around BOP stack for broaching.

Verification of Shut-In

- There should be no flow.
  - Note: any flow can quickly increase and erode equipment resulting in complications. Personnel should check gas detectors.
- Rigs offshore should post watches for signs of gas around the rig.

Shut-In on Collars

- Prior to pulling collars from the well, make a flow check.
- If a well is shut in with drill collars in the rotary, it is possible that well pressure will force the collars out of the well.
- In some cases it may be prudent to make up FOSV on joint in mouse-hole to install on collars, then run until joint's TJ is below ram, then close ram.
- If a well is shut in with spiral drill collars in the rotary, it is possible that a leak may develop in the collar's grove areas.

Shut-In with Braided Wireline

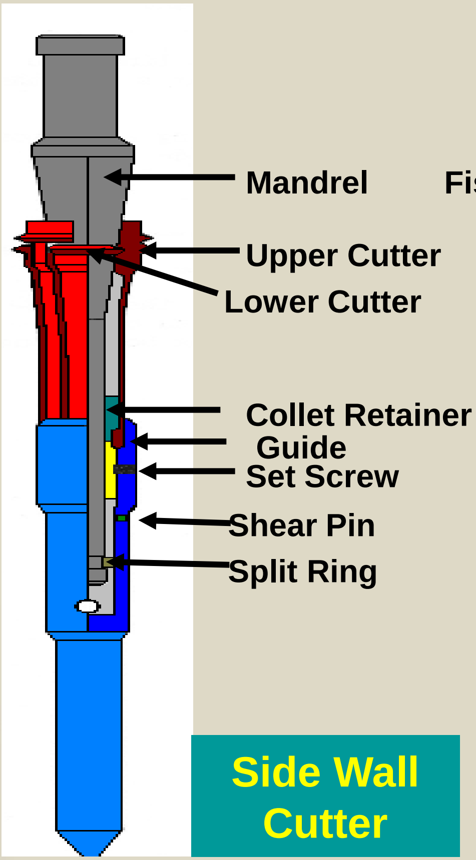
- Wireline operations usually have a lubricator in case there is pressure at the surface during the operation. The lubricator contains a:
  - Stuffing box or pack off head.
  - Grease injectors.
  - Lubricator joints or tube bodies.
  - Blowout preventers.
  - A bleed or pump-in valve.

Shut-In with Braided Wireline

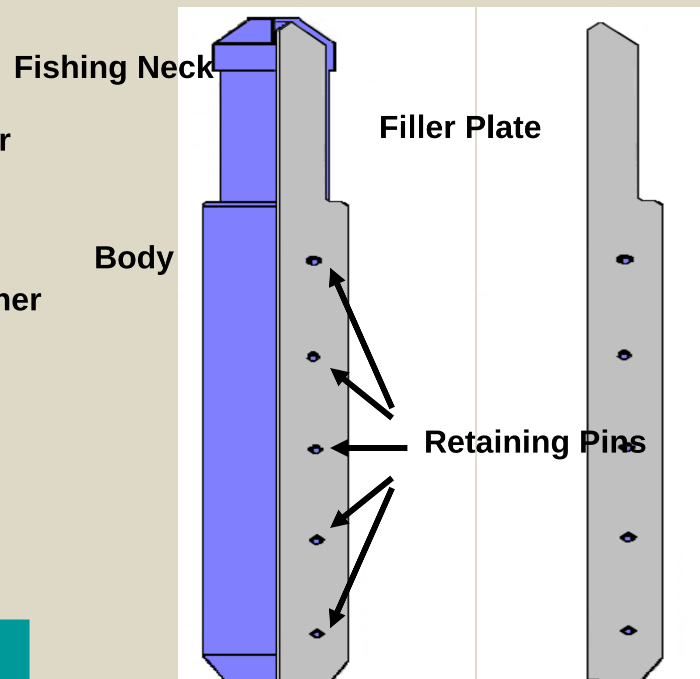
- Equipment may be nippled differently:
  - Flanged up to an annular preventer.
  - Secured inside annular preventer or rams.
  - Made up to a gauge flange on a Christmas tree.
- The shut in sequence is as follows:
  - Tell wireline operator to cease operations.
  - Driller should close the bleed or pump in valve.
  - The driller tells the designated wireline supervisor to close the wireline BOPs.
  - Inform supervisor that the well has been shut in.

Just in case, there should be a planned way to cut the wireline allowing it to be dropped and a blind ram or crown valve to be closed.

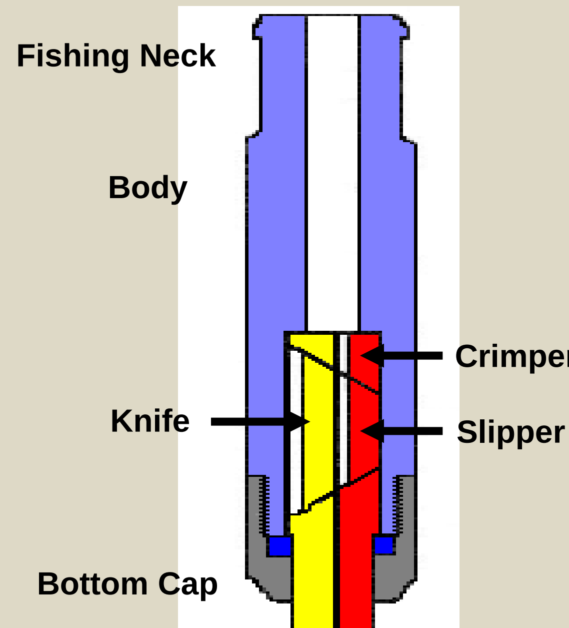
Shut-In with Braided Wireline



Side Wall Cutter



Go - Devil



Kinley Wire Cutter

Kicks While Out of the Hole

- If well flows when out of the hole:
  - Close the blind ram.
  - Monitor shut in pressures.
  - Determine best well control technique.

SIDPP and SICP

- Shut in Drill Pipe Pressure (SIDPP) and Shut-in Casing Pressure (SICP) indicate bottom hole conditions. Think of the string and the annulus as long gauge stems reaching the bottom of the well.

SIDPP and SICP

- SIDPP:
  - The fluid in the drill string is a known density with no kick contamination.
  - Since it is the purer of the two sides, it is used for pressure calculations for density increases.
- SICP:
  - Has kick fluid and cuttings commingled in it. Therefore it doesn’t give as accurate a reading on bottom hole conditions as SIDPP.

Kick Fluid Density and SICP

- The SICP, since it has kicking fluid in it, relates to the density of a kick. This is represented by the following equation:

  SICP = Formation Pressure $_{psi}$
  - Hydrostatic Pressure of Mud in Annulus $_{psi}$
  - Hydrostatic Pressure of Kick in Annulus $_{psi}$

  Or, abbreviated

  $$\mathbf{SICP = FP - HP_m - HP_{\mathit{k}}}$$

Kick Fluid Density and SICP

- Therefore, the density of the influx can be calculated if the length it occupies in the well is known.
  - If the calculated density is:
    - < 2.0 ppg, it is probably mostly gas.
    - > 8.6 ppg, it is probably mostly saltwater.
    - Between the above, it is probably a mixture. Note, could be oil if calculated to be between 5 ppg and, 7.3 ppg.

These are only approximations and all kicks should be treated as gas kicks.

Hydrocarbon Fluid Considerations

- The behavior of Hydrocarbon based fluids are subject to many factors.
  - Hydrocarbons may enter the well as either a gas or liquid depending on temperature, pressure and the formation.
    - Higher pressure and/or lower temperature = greater chance for liquid hydrocarbon. Can result in smaller pit gain.

Determining the Type of the Influx

- When there is a kick in the well, it is essential to be able to recognize the difference between a gas or liquid (oil/water) influx.
- Measuring densities will assist you in determining whether a fluid is a gas or liquid.
- Knowledge of the type of kick can help in the reduction of problems and increase successful well control.
  - Most kicks are a combination of fluids and should be treated as worst case scenario – they should all be treated as gas kicks.

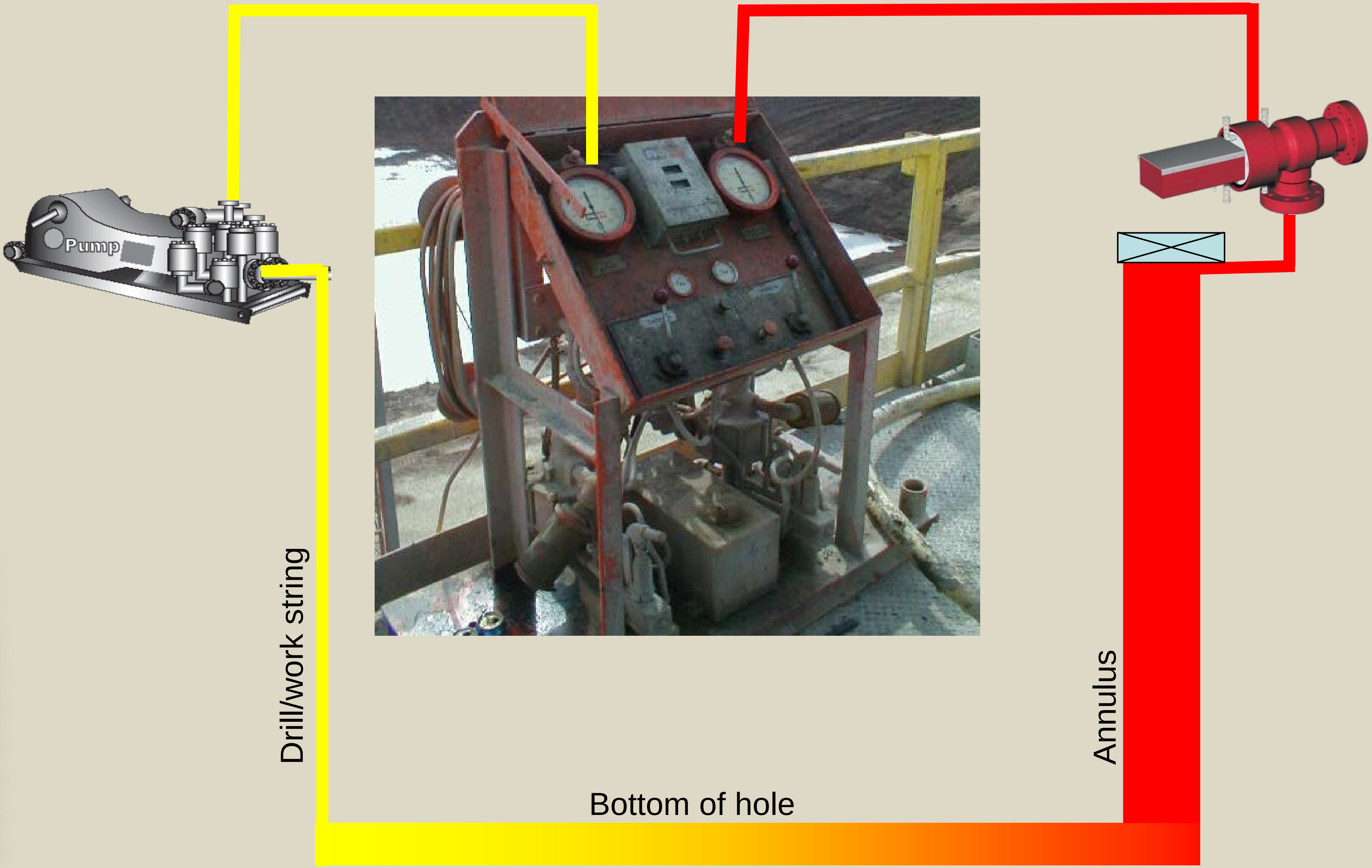
The Well as a "U-tube"

- If both sides of the U-tube are full of the same fluid and have a HP greater than formation, no formation fluid can enter.
- Suppose we could shut the well in and then raise pressure at the bottom of the U-tube by 500 psi. What would the shut in pressures be on the string and annulus at surface?

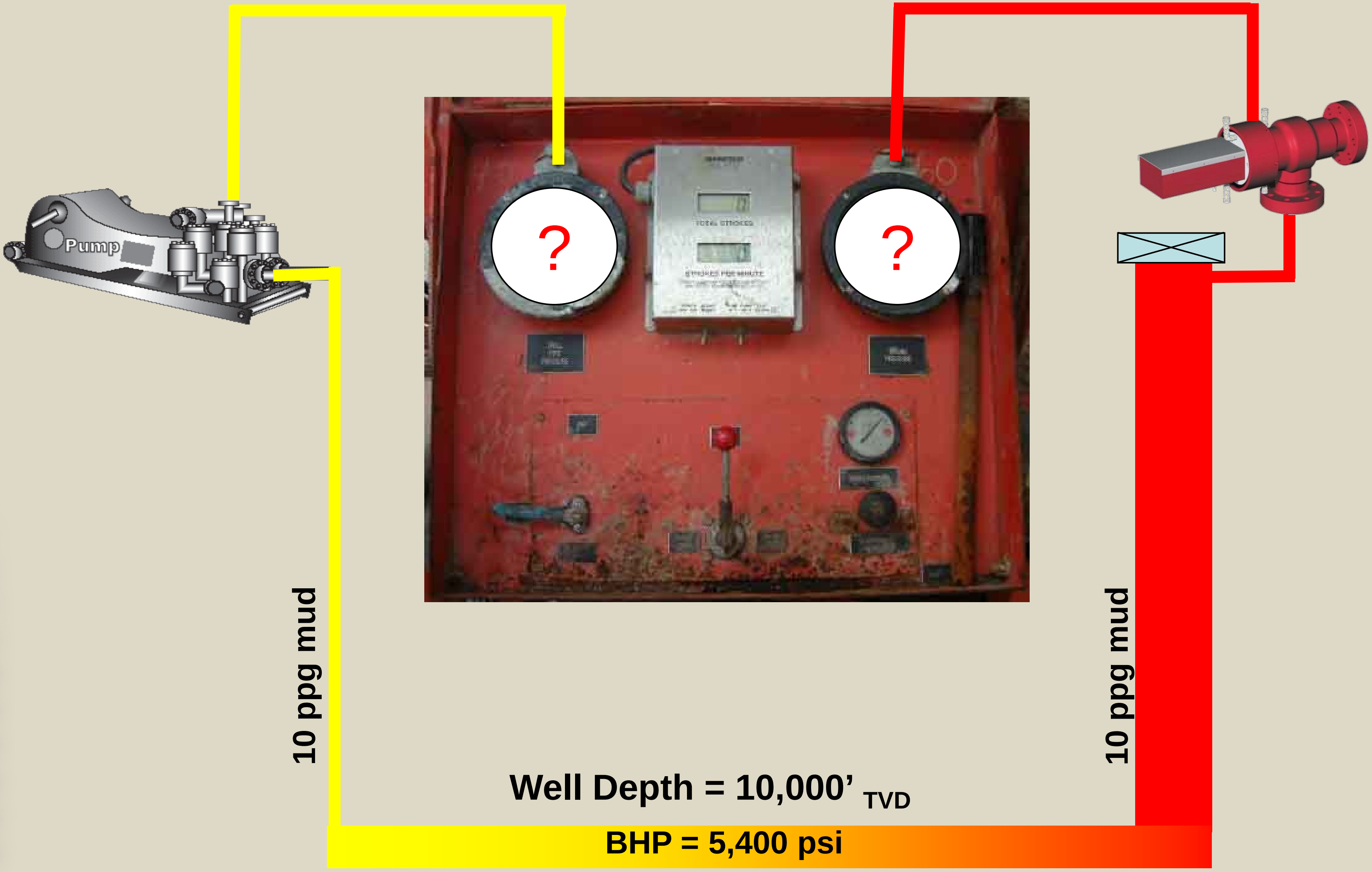
The Well as a “U-tube”

- The same things happens when a formation’s pressure is higher than the HP. A kick ensues and the shut in pressures are increased by the differential in pressure.
  - The surface gauges read the difference in formation pressure and the hydrostatic pressures in each side of the U-Tube.
    - Would SIDPP and SICP be the same?

Choke Panel Gauge Relationship



What Would the Shut-In Pressures Be?



What Would the Shut-In Pressures Be?

- If a kick entered the annulus, you would have two different fluids in the annulus of two different densities. The kick fluid replaces some of the fluid originally in the well.
- Since the kick is less dense than the original fluid and since the formation is exerting force on both sides of the U-tube, on surface which pressure reading would be greater?

What Would the Shut-In Pressures Be?

- The answer is that there is less overall HP in the annulus and therefore annulus pressure is higher. It is higher by the amount of HP differential between the original fluid’s HP and the kick’s HP.

- So, the difference between readings from SICP to SIDPP indicate the amount of HP difference.

What Would the Shut-In Pressures Be?

- Another useful concept of the U-tube is for imagining what happens to pump pressure when fluid density changes.
- As the heavier fluid is pumped down the string, circulating pressure increases due to friction of pumping it. The smaller the diameters, such as within the string (compared to the annulus), the more the friction that must be overcome
- Pump pressure will continue to increase, but much less so, as the heavy fluid is circulated up the greater diameter annulus.

What Would the Shut-In Pressures Be?

- We can predict the increase in circulating pressures by the following:

NCP = OCP X NMW ÷ OMW

Where:

NCP	= new circulating pressure, psi
OCP	= old circulating pressure, psi
NMW	= new mud (fluid) weight, ppg
OMW	= old mud (fluid) weight, ppg

- This same equation is used to calculate the Final Circulating Pressure (FCP).

What Would the Shut-In Pressures Be?

- When circulating a kick from the well, bottomhole pressure must be kept above formation pressure to prevent additional influx.
- If we add shut in pressure together with the pressure we have when circulating, bottom hole pressure will be above formation's.
- So, initially, the circulating pressure would be the pump pressure (at a consistent rate) plus the pressure originally on the SIDPP.

What Would the Shut-In Pressures Be?

- Going from shut-in conditions to circulating conditions means that we will have to circulate through a choke. So, for pump start up, the choke can be adjusted to allow flow, and still maintain the original shut in value on casing.
- Since we have to allow the gas to expand, casing pressure cannot be used to readily predict what is happening with bottom hole pressure.

What Would the Shut-In Pressures Be?

- If we adjust the choke we change the amount of back pressure exerted through the choke orifice.
- In this way we are able to adjust pressures throughout the circulating system. This is the basis for well control circulating techniques. Circulate at a predetermined rate, with known circulating pressure, then add enough back pressure to maintain the original pressure differential (formation to hydrostatic, remembering that the string has a known, pure fluid column).

Kick Size

- You should know these rules in order to estimate the maximum pressure to expect:
  - The magnitude of the kick increases casing pressure.
  - As well depth increases, so does formation and circulating pressures.
  - As fluid weight increases, so does circulating pressures.
  - Generally, surface pressures are lower with salt water kicks than with gas kicks.

Kick Size

- Surface pressure is affected by the procedure used to kill the well. Increasing the fluid weight before circulating may help minimize surface casing pressure.
- Gas migration while the well is shut in could increase surface pressures to formation pressure.
- High circulating pressures can result from added safety margins and extra fluid weight during kill operations.

Using SIDPP to Calculate FP

- Shut in drillpipe pressure is used to measure formation pressure, kill weight mud and initial circulating pressure, so it is essential that pressure recordings and calculations are accurate.
- Since SIDPP indicates the pressure to balance formation pressure, we can add it to existing hydrostatic in the string to calculate formation pressure. The following equation shows the relationship.

Formation Pressure = Hydrostatic Pressure + SIDPP

Using SIDPP to Calculate FP

- It is assumed that the shut in drillpipe pressure is correct, and should be lower than the shut in casing pressure.
  - However, it is possible to have a greater shut in drillpipe pressure than casing pressure as long as the overall density of the fluids in the annulus is heavier than in the drillpipe.

Using SIDPP to Calculate FP

- Reasons that shut in drillpipe pressures can appear as very high or low:
  - There are trapped pressures.
  - The person reading the pressure did not allow the formation pressure to stabilize and took a reading too early.
  - The person reading the pressure read the pressure too late, after gas migration had its effects on it.
  - The pipe may U-tube and be partly empty from a large kick.

Fluid/Mud Weight Increase

- It is necessary increase in fluid density to bring the well back into hydrostatic pressure control. The increase can be calculated using SIDPP.
- Remember that SIDPP has a pure column of fluid, and any pressure registering on the standpipe gauge reflects how much hydrostatic pressure is lacking.
- The calculation is:

$$\textbf{Kill Weight}_{\textbf{ppg}} = \textbf{SIDPP}_{\textbf{psi}} \div \textbf{Depth}_{\textbf{Ft,TVD}} \div \textbf{0.052}$$

Fluid/Mud Weight Increase

- Another reason for a slow rise in SIDPP and SICP is a formation with low permeability. It slowly feeds in when shut in and slowly equalizes.
- If records are kept and a simple plot made (pressure against time), the slope of the plot changes after the well is equalized.

Fluid/Mud Weight Increase

- If records are not kept, incorrect and low SIDPP reading may be used.
  - Kill fluid density and circulating pressures will be incorrect, further allowing additional influx and complicating the well kill.
- Generally speaking, after a reasonable amount of time (assuming that no pressure limitations are reached) if pressures are still increasing, it is due to gas migration.

Low or No SIDPP and SICP

- Other causes for incorrect pressures, such as little, low or no pressure readings can be due to:
  - Gauges are incorrect.
  - Gauge is plugged.
  - Gauges are shut off.
  - Pressure is too low for the range of the gauge.
  - Float in the string.

Low or No SIDPP and SICP

- If equipment is working properly, slowly open choke and check for flow. If flow is detected shut well back in and obtain and rig up lower pressure scale gauges.
- If in doubt if there is pressure, or if there is a potential kick in the well, use the driller’s method and circulate bottom’s up, shut in and recheck.

Gas Behavior and Solubility

- Gas behavior and solubility depends on the type of fluid in use, pressure, temperature, pH, and the amount of time that the gas is exposed to the liquid.
- Methane and hydrogen sulfide are more soluble in oil based solutions than water based solutions.

Gas Behavior and Solubility

- Gas can be compressed into liquid with enough pressure.
  - Liquid gas kicks will not migrate significantly.
  - Gas will expand rapidly once it reaches its bubble point.
- Changes in conditions, such as pressure, can cause unexpected expansion.

Oil/Synthetic Oil Based Mud and Migration

- Gas kicks in oil based fluid behave much differently than gas kicks in water based fluids.
- Gas in oil based fluids will mix/dissolve into solution.
  - In water based fluid oil does not exhibit the same effect.

Oil/Synthetic Oil Based Mud and Migration

- Gas dissolved in solution will not migrate as much as gas free from solution.
  - So, gas in oil based fluids often appears to be a liquid kick – another reason why every kick should actually be treated as a gas kick.

Gas Laws and Gas Expansion

- In well control gas laws such as Charles' Law, Boyle's Law and ideal gas equation, all illustrate that:
  - The volume gas occupies is related to the pressure imposed on it.
  - Even a small volume of gas has the potential to expand greatly.
  - If a gas is not allowed to expand, gas pressure stays constant except for changes in temperature.

Gas Laws and Gas Expansion

- If gas comes from the bottom of the hole to the top without being allowed to expand, it will carry the same amount of pressure to the top that it had at the bottom.
  - The pressure exerted by this gas will pressurize the well and eventually cause equipment failure, formation breakdown, or lost circulation.
- Gas law calculations can be very complex and require specific temperature and known types of gas.

Gas Laws and Gas Expansion

- Gas cools as it comes up the hole, and if gas is allowed to expand, then it cools even more and the pressure of the gas is reduced.
- The solubility of gas also plays a role in its pressure.
  - When a gas is dissolved into fluid, it reduces the volume of free gas and pressures at the surface are reduced.
- Although gas should be allowed to expand at the surface, it should be a controlled expansion.
  - This is because if gas is expanded too much, the gas will take up too much volume in the annulus and push large amounts of fluid out of the hole, causing a reduction in bottomhole pressure.

Shortened Gas Expansion Equation

- Without knowing the exact type of gas, or gas mixtures, it is difficult to predict how a gas will react under pressure. We do know that it will expand.
- Note: this general equation can be useful for other pressure volume relationships.

Shortened Gas Expansion Equation

- A simplistic gas equation, (ignoring the type of gas, compressibility factor and temperature) for gas expansion derrived from more complex gas laws is:

$$P_1 \text{ X } V_1 = P_2 \text{ X } V_2$$

Where:

P_1 = formation pressure, psi

P_2 = total pressure, psi at any other point, or atmospheric pressure once the gas is at surface.

V_1 = original pit gain, bbls

V_2 = gas volume at surface, bbls

Gas Migration Equation

- The rate that gas migrates through a fluid can be easily calculated.
- Use the change in SICP over an hour's time with the following equation:

$$\textbf{Rate}_{ft/hr} = \Delta \textbf{SICP}_{psi} \div \textbf{Mud Gradient}_{psi/ft}$$

Estimated Maximum Surface Pressure from a Kick

- Many factors influence the maximum pressure that will be seen on surface:
  - Type of kick
  - Type of fluid in use
  - Solubility of kick in fluid
  - Migration
  - Expansion
  - Temperature

Estimated Maximum Surface Pressure from a Kick

- Because of this, we cannot accurately predict maximum pressure.
- There are several equations that will give estimates and may be useful when planning the kill technique including the following:

$$MSP_{gk} = 0.2 \times \sqrt{(P \times V \times W) \div C}$$

Where:

MSP_{GK} = Maximum surface pressure from a gas kick, psi

P = Formation Pressure, psi

V = Original pit gain, bbls

C = annulus capacity, bbls/ft

W= kill fluid density, ppg

Calculating Maximum Pit Gain

- In some instances it is desirable to know the maximum volume that will be displaced from the well.
- The same influencing maximum pressure also influences maximum pit gain.
- Several equations can be used to predict gain. A simplistic one is:

$$MPG_{gk} = 4\sqrt{(P \times V \times C) \div W}$$

Where:

MPG_{GK}	= Maximum pit gain from a gas kick, bbls
P	= Formation Pressure, psi
V	= Original pit gain, bbls
C	= annulus capacity, bbls/ft
W	= kill fluid density, ppg

Gas Migration and Expansion

- Gas or gas bubbles float, or migrate up the hole because it is lighter than the fluid in use.
- When shut-in gas migrates.
- When shut-in the well should be monitored. Increases in pressure should be bled off according to volumetric procedures.
- Bleed in small increments. Try to maintain constant SIDPP to ensure that bottomhole pressure is also kept constant.

Liquid Kicks and Migration

- Liquid kicks such as oil and/or saltwater are much closer in density to mud.
- Liquid kicks do not migrate as much as gas kicks do.
- Liquid kicks will mingle with the existing fluid, essentially stopping migration.
- Liquid kicks will not expand so pit level during circulation will remain fairly constant as long as no more influx is allowed.

REMEMBER: It is important to treat every kick as if it were a gas kick.

Burst and Collapse Pressures

- There are many factors to consider during well control operations. If this pressure exceeds surface equipment ratings alternate well control methods must be considered.
- Burst and collapse of tubulars should be known. These are commonly available in industry charts and tables.
- Factors affecting tubular pressure ratings include:
  - Condition (new, used and used condition)
  - Grade
  - Weight
  - Biaxial loading

Burst and Collapse Pressures

WILD WELL CONTROL

Tubing Size	Connection Data: Outer Dia. In.	Connection Data: Inner Dia. In.	Connection Data: Make-up Torque	Grade	Tube Data: Outer Dia. In.	Inner Dia. In.	Drift	Wall Thick	Cross Section	100% Yield	Ult. Strength	Depth 100%	Pull 100%	PSI Burst 100%	Collapse 100%	Cap. (Gals/1000 ft)	Disp. (Gals/1000 ft)	Capacity (bbls/ft)	Disp. (bbls/ft)
2-3/8" PH-6 HYDRIL 5.95# N-80/L-80	2.906	1.805	2,200	N-L-80	2.375	1.867	1.773	0.254	1.692	80,000	100,000	22,700	135,000	17,100	15,300	142.2	91.0	0.00339	0.00217
2-3/8" PH-6 HYDRIL 5.95# RY-85	2.906	1.805	2,200	RY-85	2.375	1.867	1.773	0.254	1.692	85,000	100,000	24,100	143,800	18,200	16,240	142.2	91.0	0.00339	0.00217
2-3/8" PH-6 HYDRIL 5.95# T-95	2.906	1.805	2,200	T-95	2.375	1.867	1.773	0.254	1.692	95,000	110,000	27,000	160,740	19,665	17,595	142.2	91.0	0.00339	0.00217
2-3/8" PH-6 HYDRIL 5.95# P-110	2.906	1.805	2,700	P-110	2.375	1.867	1.773	0.254	1.692	105,000	120,000	29,900	178,000	22,500	20,060	142.2	91.0	0.00339	0.00217
2-7/8" EUE 8RD 6.5# N-80/L-80	3.668	2.441	2,300	N-L-80	2.875	2.441	2.347	0.217	1.812	80,000	100,000	22,300	145,000	12,100	11,160	243.0	99.5	0.00579	0.00237
2-7/8" PH-6 HYDRIL 8.7# N-80/L-80	3.500	2.200	3,000	N-L-80	2.875	2.259	2.165	0.308	2.484	80,000	100,000	22,800	198,700	17,140	15,300	208.1	133.1	0.00495	0.00317
2-7/8" PH-6 HYDRIL 7.9# N-80/L-80	3.437	2.265	3,000	N-L-80	2.875	2.323	2.229	0.276	2.254	80,000	100,000	22,800	180,000	15,300	13,900	220.0	120.9	0.00524	0.00288
2-7/8" PH-6 HYDRIL 7.9# T-95	3.437	2.265	3,200	T-95	2.875	2.323	2.229	0.276	2.254	95,000	110,000	27,098	214,082	18,000	16,000	220.0	120.9	0.00524	0.00288
2-7/8" PH-6 HYDRIL 7.9# P-110	3.437	2.265	3,500	P-110	2.875	2.323	2.229	0.276	2.254	105,000	120,000	29,900	236,000	20,100	18,200	220.0	120.9	0.00524	0.00288
3-1/2" EUE 8RD 9.3# N-80/L-80	4.500	2.992	2,400-3,200	N-L-80	3.500	2.992	2.867	0.254	2.590	80,000	100,000	22,200	207,200	11,600	10,700	365.2	134.5	0.00870	0.00320
3-1/2" EUE 8RD 9.3# P-110	4.500	2.992	3,000-4,000	P-110	3.500	2.992	2.867	0.254	2.590	110,000	125,000	30,600	284,900	15,900	14,800	365.2	134.5	0.00870	0.00320
3-1/2" PH-6 HYDRIL 12.95# N-80/L-80	4.312	2.687	5,500	N-L-80	3.500	2.750	2.625	0.375	3.682	80,000	100,000	22,700	294,500	17,100	15,310	308.4	198.1	0.00734	0.00472
3-1/2" PH-6 HYDRIL 12.95# T-95	4.313	2.687	6,000	T-95	3.500	2.750	2.625	0.375	3.682	95,000	105,000	27,000	386,600	20,300	18,100	308.4	198.1	0.00734	0.00472
3-1/2" PH-6 HYDRIL 12.95# P-110	4.312	2.687	7,000	P-110	3.500	2.750	2.625	0.375	3.682	105,000	120,000	29,800	386,600	22,500	20,090	308.4	198.1	0.00734	0.00472
4-1/2" PH-6 HYDRIL 15.50# P-110	5.125	3.765	8,500	P-110	4.500	3.826	3.701	0.337	4.407	110,000	125,000	31,300	485,000	16,480	14,340	598.0	229.2	0.01424	0.00546

Wild Well Control

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High Pressure – High Temperature

- High pressure > 10,000 psi
- High temperature where choke temperatures could exceed 300^{o}F
- HPHT wells combine both extremes
- Planning:
  - Computer models should be run to simulate maximum gas and fluid flow rates as well as maximum temperature from the highest pressured zone through open choke manifold.

High Pressure – High Temperature

- Consideration should be given to the manifold as high gas flow rates may create hydrates downstream of choke. It may be necessary to install glycol injection line. Also, use of glycol to inhibit hydrate formation may be left in choke/kill lines and manifolds
- Mud Gas Separator capacity should be modeled and low pressure sensors used to detect pressure differential. Heaters and mud injectors may be used to minimize hydrate from forming.

High Pressure – High Temperature

- Equipment should be rated higher than max modeled surface pressure. Also, equipment must be H_2S trimmed and all elastomers rated for anticipated temperature and pressure.
  - Extra casing run contingency planned.
  - Casing runs should plan for the use of casing pipe rams.
  - Consideration to temperature probes at wellhead, stack or manifolds to monitor extreme pressures.

High Pressure – High Temperature

- Pump kill-rate speeds must be selected to not exceed the capacity of surface equipment. Accurate recording necessary.
- Crews should be well briefed on well behavior.
- Indications of swabbing may require circulating bottoms-up through choke.
- Precautions should be taken prior to every connection. Top drive rigs may install FOSV on bottom stand to be installed.

Handling Gas at the Surface

- Until the type of kick is known, the entire rig crew should be notified that there is potential for toxic and/or flammable gases.
- Personnel should check gas detectors.
- After the well is shut-in, personnel should observe the wellhead, BOPs, manifolds, choke, and kill lines for possible leaks.
- Rigs offshore should post warning signs of gas around the rig.

Handling Gas at the Surface

- Leaks should be reported immediately.
- If attempting to tighten a connection to repair leaks, a brass hammer should be used to avoid sparks.
- Align the choke to the gas separator after the well is shut in, and make sure that the separator is working correctly.
- Monitor the separator during circulation for pressure buildup.
- The downwind vent and flare lines should be open and igniter operational.
- Stop all potential sources of ignition not necessary to the operation.