Completions & Workovers

Learning Objectives

- You will learn -
  - The reasons why a well needs to be worked over.
  - The benefits derived from working a well over.
  - To prepare a well completion.
  - To design a completion for the type of reservoir.

- You will also learn -
  - The types of well completion equipment.
  - The surface completion equipment needed.
  - The downhole completion equipment needed.
  - You will also review how to control and kill live wells.
Completions & Workovers

Overview

- We will design the well from start to finish.
- We will review ways to work the well over.
- We will utilize kill methods.
- We will review different workover methods.
- We will review methods to keep operators on track for proper workover procedures.
Completion Design

The completion designed can be broken into five phases –

- Establishing design criteria.
- Preparation of the production zone.
- Mechanical completion of the well.
- Initiate production and apply treatment procedures.
- Monitoring & assessment of the wells and the performance of the completion.
Completions & Workovers

- Integrating the five phases -
  - Efficient completion is a complex process.
  - Must use a rigorous approach to establish design criteria.
  - Comprehensive formation evaluation program is essential

- Well completion design is a dynamic process, it must include -
  - Feedback from completion performance data.
  - Changes in design criteria.
Completions & Workovers

- Design process to allow flexibility for operational requirements and uncertainties in available design data.
- Completion has limited number of specific tubular components.
- Overall number of components affects complexity of completion and its reliability.
Well Completion Tips

- **When arriving on location** -
  - Count the joints of tubing.
  - Number all joints of tubing.
  - Rabbit the joints of tubing.
  - Check the threads and pin ends.
  - Lubricate the tubing joints.
  - Check the completion equipment.
  - Check the I.D. to ensure it is the proper diameter for the completion string.
Well Completion Tips

- If running a combination of nipples, (selective and NO-GO), be sure that you know how to install them correctly.
- If installing hydraulic, or hydrostatic set packers, check I.D’s, check that all shear pins are in place and none are missing.
- Bi-Directional slips -
  - Check that slips are functioning correctly.
    - May not be aligned properly.
    - Will only move part way.
    - Will keep the packer set from below.
  - Ensure bi-directional slips are aligned properly.
Well Completion Tips

- Check that the packer has a setting port drilled into the inner mandrel of the packer.
- Know the setting area of the packer.
- Calculate the setting force needed -
  \[ \text{Setting force}_{\text{lbs}} = \text{Setting area}_{\text{sq. in.}} \times \text{Hyd. setting pressure}_{\text{psi}} \]
  - The actual depth that the packer will be set should be measured from the sealing elements.
  - Now the completion string is run and installed.
  - Note: the completion string is not only a mechanical hookup that you are putting inside of the wellbore; It is also pressure vessel.
Well Completion Tips

- Several small things done incorrectly will lead to failures.
- Normal completion string running speed is a stand per minute.
  - If more than 10% of dead hanging weight is lost, then it is being run too fast. This can cause the well to be surged.
- If running a hydraulic or hydrostatic set packer, do not run setting ball or standing valve in place. The water hammer effect will prematurely set the packers, because it will shear the setting pins.
- When landing the completion string, be sure that the seal on the tubing hanger is in good working shape.
Well Completion Tips

- Always have a back pressure valve installed in the tubing hanger.
- When removing the back-pressure valves, NEVER dry rod the back pressure valve from the tubing hanger.
- Always install a lubricator for pressure control.
- Drilling fluid in well can be circulated out with the completion fluid after the X-mas tree is installed.
- Packers with metal fold back rings on each end of the sealing elements will protect them from pump pressure wear.
- A circulating rate of about one bpm is a good rate when displacing fluids.
Well Completion Tips

- Drilling fluid displacement can be done either with forward or reverse circulation when using a hydraulic set packer.
- If the packer is a hydrostatic set packer, you can only displace it by reverse circulation.
  - Forward circulation will set packer prematurely.
- A surging rig pump should never be used to displace drilling fluid as it is possible to prematurely set a hydraulic or hydrostatic packer.
- Ensure hydraulic and hydrostatic set packers are at proper setting depth before you starting displacement. You must have a circulating device (sliding sleeve, SPM) installed in tubing string.
Well Completion Tips

- If you don’t know why a certain type of packer is used, then check with your supervisor.
- Know the setting mechanism of the packers, how it sits, and learn the problems you can encounter.
- Set hydraulic or hydrostatic packers with a ball if the formation will take fluid.
- Don’t use a ball to set packers if the formation won’t take fluid. Use a standing valve or hydrotrip sub to set packers.
Well Completion Tips

- When installing a single well with multiple production zones, ensure there is no tubing movement between packers. If tubing movement is present install expansion joints between packers.
- If the well has been installed for gas lift, do not inject gas too fast and cut out the gas lift valves.
- Do not restrict the flow by installing too many 90° angles in the flow line; streamline the flow line.
- Always install a positive choke in the flow line.
- All wells under MMS regulations must be installed with surface controlled sub surface safety valve.
Well Completion Tips

- SCSSVs must be installed at a depth below the mud line to give protection in case of an impact or explosion at surface. (MMS dictates SCSSVs must be installed 100 feet below the mudline)
- Place circulation devices one joint above packer, never directly on top.
- Do not circulate too fast through sliding sleeves or side pocket gas lift mandrels.
  - Fast circulation cuts sleeves and mandrels out.
- If setting hydraulic set packers, do not use the bottom layers of barite weighted mud as weight may not be consistent.
Well Completion Tips

- Run tubing conveyed perforator below packers. Use tubing string weight and hold back pressure on top of packers. This keeps from blowing the completion string up the hole.
- If using an equalizing standing valve to set hydraulic set packers, the standing valve has to be equalized before it is pulled.
- Always install two way check valve in the tubing hanger to pressure test the X-mas tree and valves.
Packers

- **Types of Packers** –
  - Permanent
  - Permanent Retrievable
  - Mechanical Set
  - Hydraulic Set
Permanent Packers

- High Temp Packer
- Sump Packer
- Tubing Set
- Hydraulic Set
- Wireline Set
Permanent Packers

Wireline Set Packer
- Scoop Head Design
- Overshot
- Seal Guide
- J Latch Receiving Head
- Internal Locking Slips
- Case Carburized Upper Slips
- Triple-Seal Multi-Durometer Element Package
- Metal Back-up Shoes
- Case Carburized Lower Slips

Hydraulic Set Packer
- Internal Locking Slips
- Triple Slips Multi-Durometer Package
- Sealing Bore
- Setting Sleeve
- Cylinder
- Setting Piston
- Setting Rotation Feature

Tubing Set Packer
Permanent Packers

- Mandrel
- Case Carburized Upper Slips
- Case Carburized Lower Slips
- Severe Environment Packer
- Hi-Temp Element Package
Typical Permanent Packer

Wireline Set

Hydraulic Set
Packers

- Designed for single-string completions.
- For emergency pulling, straight pull will unseat the packer.
What are the advantages of using an isolation tool squeeze packer?

- Face seal unloaded (valve) located at the top of the tool seals off the inside tubing.
- Has a built-in balance sleeve system that holds the valve closed when tubing psi is greater than the annular psi.
- By-pass system, located at top of the packer allows circulation above packer.
- Three piece sealing element.
- Jay slot and slips located below sealing elements holds the packer and prevents downward movement.
Isolation Packer

Q&A #1

- This well has 3 productive zones. The company wants to acid/frac each zone, clean them out, set a packer and tubing string as a production string.
  
  - *What type of packer must you use?*
  
  **Answer** - The type of packer must be a hook wall packer with hydraulic hold down buttons.
**Q&A #1**

- Can all these things be accomplished in one trip or must you make several trips?
  
  - Yes they can if you do not have a thief zone (in this case all 3 zones have the same pressure with shale stringers between the productive sands).

  - After frac'ing the zone, the packer is released. Then, wait until the sealing element returns to its original shape or as close as possible. (approx.15-20 mins or a cup of coffee and two cigarettes)
Isolation Packer

- Next, lower the unseated packer down hole slowly and reverse out the excessive debris.
- Then, pick up the packer above the zones after cleaning them up and re-set the packer.
- Depending upon what type of packer is selected, release and re-set. (the packing elements will try to return to their original position)
Wire line Set Cement Retainer Model K-1

Mechanical Set Cement Retainer Model K-1

Wire line Set Cement Retainer With Flapper Valve Model K-1

Mechanical Set Bridge Plug Model N-1

Mechanical Set Cement Retainer w/Flapper Valve Model K-1

Isolation Packer
Packers

• Hydraulically Set Retrievable Packer
  ▪ The packer is set hydraulically by pressuring up on tubing against a check valve located below packer.
  ▪ The packer can also be set with a standing valve, positive wireline-set plug or a hydrotrip sub.
Packers

- Hydraulically Set Retrievable Packer
  - Packer is retrieved by a straight pull on the tubing string.
  - Catcher subs accept a brass ball as a check valve.
  - Expendable catcher sub is normally used.
Hydraulically Set Retrievable Packer

Expendable Catcher Sub
Setting Hydraulic Packer w/Pump Out Sub

- 2-3/8" OD Tubing
- Tubing Fluid: Diesel 7.0 ppg
- Casing: 7" OD, 6.25" ID
- Ball
- Perforations: open but not taking fluid.
- Tight Gas Sand
- Bridge Plug
- Hydraulic Set Packer
- Annular Fluid: Brine 10.0 ppg
- Tubing Fluid: Diesel 7.0 ppg
• How much Force (lbs) is exerted under the packer?

• To release the ball we need 4,000 psi of pressure.

Force lbs.

= Area x Well Pressure
= ID² x 0.7854 x Well Pres.
= 6.25 in x 0.7854 x 4,000 psi
= 122,719 lbs force
• Ball goes down and hits bridge plug.
• This allows communication with the production zone and the tubing.
Setting Hydraulic Packer w/Pump Out Sub

- Force travels up.
- Full impact of the pressure is exerted on the packer.
Setting Hydraulic Packer w/Pump Out Sub

- Impact blows and unseats the packer and moves with the completion string up hole.
Typical Retrievable Packers

Single Hydraulic Packer

Dual Hydraulic Packer
Packers

- Baker Model FH packer is hydrostatically set with a field adjustable shear release mechanism.
- To set packer a ball, standing valve, hydrotrip sub, or a positive plug must be installed below the packer.
Packers

- Model DAB packer can serve as Baker Model FH packer is hydrostatically set with a field adjustable shear release mechanism.
  - Production packer
  - Zone isolation packer
  - Reliable squeeze packer
Packers

**Hydrostatic-Set Packer**

- This packer type is designed to be run and set in -
  - Highly deviated wellbores.
  - Horizontal wellbores
  - When conventional running and setting techniques are difficult to achieve.
  - It uses existing hydrostatic pressure of the wellbore to set the packer.
Packers

- The Type BB packer is a retrievable packer that can be run on -
  - Conventional electric line
  - Slickline
  - Coiled tubing
  - Conventional workstring
The tubing conveyed perforating tool is run below the packer with the tubing.
Tubing Conveyed Perforating

- Gun is fired by dropping firing bar after setting packer.
Tubing Conveyed Perforating

- Displace drilling fluid with completion fluid.
Tubing Conveyed Perforating

- Well bore is charged from the perforations by 7,000 psi of formation pressure after perforating.
Tubing Conveyed Perforating

- Pressure from the formation returns and travels downwards and upwards.
- Forces then rebound.
- Now calculate the force underneath the packer.
Tubing Conveyed Perforating

- Force = \((\text{ID, in.})^2 \times 0.7854 \times \text{Pressure, psi}\)
  
  \[
  (6.25)^2 \times 0.7854 \times 7,000 = 214,758 \text{ pounds}
  \]

- Plus 50,000 pounds shock force (from firing perforating tool)

- Total Force = 214,758 + 50,000 = 264,758 lbs
Tubing Conveyed Perforating

- Force travels up -
  - Corkscrews tailpipe (tubing below packer)
  - Bursts casing at packer seal
Tubing Conveyed Perforating

- Tubing is -
  - Corkscrewed
- Packer is -
  - Unseated
  - Blown up hole
Permanent Packer Accessories

Locator Seal Assembly

“G” Locator

Seal Extension

Extension

Anchor Latch

“K22” Anchor Seal Nipple

“EBH22” Anchor Seal Assembly
These types of completions have been run.

Experience has taught us to make sure that the packers were always at the proper setting depths.

The shifting tools were run. The top to shift down to open the sleeve. The lower shifting tools shift upward to close.
太重的重量被施加在隔隔器上，导致短串钻具螺旋打滑。

- 有什么可能的解决方案？
Dual Completion

- The sliding sleeve in the long string was opened below the dual packer.
- The plug had to be pumped down by a pump truck, because the tubing was corkscrewed.
- The plug was set.
- The pump was swapped to the long string and pressured up below the plug in the short string.
- The upward force removed some of the weight from the short string and the packer set.
Dual Completion
Landing Nipples and Key Profiles

Type X

Key Profile

Seal Bore

Type XN

NO-GO
The nipple, left, has a sliding sleeve which prevents solids blocking the control line port when valve is out of the hole.

Standard nipple, right, lacks the inner protective sleeve.
- The sleeve shifts each time the valve is set or pulled.
- When the valve is set, a shifting mandrel attached to the locking mandrel shifts the sleeve open.
- Sleeve closed when safety valve is pulled from nipple.
Down hole Safety Valve Nipple

- Sleeve closed when safety valve is pulled from nipple.
- A shifting tool can open sleeve prior to setting the wireline safety valve in the nipple.
- The control line then attaches to the tubing hanger and is accessible via a needle valve mounted to the tubing spool.
- The control line of ¼” SS tubing attaches to the nipple and is strapped to the tubing as it is made up and run in the hole.
- In deep set safety valves an additional hydraulic line is attached to this valve to enable increased hydraulic fluid and pressure to be supplied. This becomes a necessity in deep set safety valves.
Tubing Nipples and Lock Mandrels

- Production tubing nipples are special tubulars made up as part of the production string incorporating a machined profile into which specific locking devices can be set.

- Pictured at left is a Position 1 S Lock Mandrel and its companion nipple. The nipple and mandrel are said to be selective as per the nipple profile and matching locator key profile. There are numerous “positions” for this type of nipple and locking device which allows freedom as to the specific nipple and depth a flow control device will be set. Shown below is an example of varying positions available for this equipment. The locator portion of the nipple is machined to a specific profile and matching locator keys are installed on the locking device. The locking device will only set and lock in its matching nipple.
Another form of a positive plug is one that is run on an S or T locking device. The prong, once again, serves as an equalizing device, but in this case, it is run with the plug body as the prong is pinned to the valve.
Pulling of the plug entails two trips in the hole. The first trip to pull the prong achieving pressure equalization and the second trip retrieves the locking mandrel and the plug.
“X” & “XN” Wireline Landing Nipples

“X” Selective Landing Nipple

Orientation Groove
Key Profile
Seal Bore

“XN” NO-Go Landing Nipple

Orientation Groove
Key Profile
Seal Bore
Trash Groove
No-Go Shoulder
Flow Couplings and Blast joints are Specialty tubulars w/ thicker walls to protect the completion string.
Flow Couplings

- Flow couplings eliminate turbulence existing above and below a nipple due to its restriction.
- Installed above and below tubing nipples.
- Thicker walls resist erosion better.
Blast Joints

- Placed in tubing string opposite, open and at flowing perforation or tubing hanger depth. At both of these depths there is extreme flow which can cause tubular erosion.
- Protect tubing from –
  - Excessive wear
  - Premature failure
Tubing Nipples and Mandrels

- Tubing Nipples are selective as per the running tool. (this allows bypassing of shallower nipples to set nipples at the desired depth)

- All nipples run in the tubing of this type (“CAMX”) have the same profile with the exception of the NO-GO nipple containing the NO-GO restriction.
• The running tool used to run and set the equipment allows the operator to select a specific depth to install flow control devices based on various depth of the nipples.
- The AX is a plug installed on an CAMX locking mandrel.
- The plug body, made up of the lock mandrel, equalizing sub, and valve cap are run and set in the desired CAMX nipple.
- A standard pulling tool is run to retrieve the prong for equalization.
- Another trip is made to pull the plug body.
Nipples and Mandrels

- The CAMXN (locking) nipple has a NO-GO ring machined into the bottom. This allows only a mandrel with a No-Go ring to be installed.
- This nipple is the lowest run in the tubing string because of the presence of the NO-GO restriction.
Locking Device: Landing Nipple/Safety Valve
Locking Dogs

- Two types of locking dogs for the selective and the NO-GO nipples.
Circulating Devices

- Sliding Sleeve
  - Circulating devices
  - Production devices
- Side pocket mandrel
  - MM series
  - KB series
A SS is a window placed as a part of the completion string which allows communication with annulus.

Opening or closing the sleeve is with a shifting tool which locates in a machined profile in the inner sleeve.
A nipple profile can be installed above the SS. This profile is used to blank (close) off the ports by installing an isolation tool. The same is true when, you want to produce through the SS then, a separation tool is installed in the nipple profile.

- NOTE:
- Sliding sleeves are installed to open up or down, depending on the application.
SS and Shift Tools

- The pin x pin “B” shift tool may be run so the sleeve can open either direction this dictates how the shifting tool is run.
SS and Shift Tools

- The right angle shoulders of the locator keys match a machined profile in the sleeve.
- After the sleeve has shifted, the tool releases from the shifting profile.
A side pocket mandrel has been run in the horizontal part of the well in the next slide and has rotated to the top side of the well bore.

When the well was completed, the design engineer was told to be sure the well could be worked over and killed by circulating through the side pocket gas lift mandrel.

Study this drawing and give the design engineer the proper methodology to establish communication between the tubing and annulus.
Q&A #1
What are your recommendations?

Wireline and coil tubing are poor choices. The correct way would be to install a dump kill valve (this is a burst disc one way valve) in the side pocket mandrel and open it by applying pressure on the annulus.
Gas Lift Equipment and Systems

- One type of gas lift which can be installed in wells that were not initially completed with gas lift equipment is a gas lift packoff.
- Rather than pulling the tubing, packoff type gas lift assemblies can be installed.
Gas Lift Equipment and Systems

- The tubing is perforated at the desired depths and the assemblies as seen at left are installed opposite the perforations. Installation and servicing of the equipment can be performed by wireline or coiled tubing.
- In the illustration slip type stop devices are used to hold the assembly in place but, as seen in the inset at lower left, collar locks can be used as well – usually as the lower stop with a slip stop at the top of the packoff.
Old Type Kick-Over Tools

- The appropriate pulling or running tool for the gas lift valve would be installed below the kick-over tool.
Down-hole Safety Valves

- The Series 10 Flapper Valve is a hydraulic valve, NC (normally closed) operated from the surface.
- Full bore to tubing on which it is installed.
Down-hole Safety Valves

- Allows servicing of well thru safety valve.
- Valve has a lock-out feature
- In the event the valve becomes inoperative, the internal safety valve nipple may be used after the tubing retrievable safety valve has been locked out.
Kickover Tool

- Running and Retrieving Tools for Side Pocket, Mandrels, Kick over Tool.
The safety valve is a NC valve which must have hydraulic pressure supplied in order to operate.

- Lock-out feature capability for the installation of a wireline valve
- The flow tube protects the flapper during well production
The Storm Choke (velocity valve) is a direct-controlled, normally open valve -

- Spring and spacers determine the spring force used to hold valve open.
- When pressure differential across valve reaches a pre-determined point and is less than spring tension, valve closes.
Storm Choke (Velocity Valve)

- To reopen the valve, pressure is applied to the tubing or an equalizing prong can be run into the valve and equalizing sub.
- The valve, right, is attached to an X locking mandrel but can be attached to many different types of locking devices.
The Storm Choke is an ambient, normally open valve, pre-charged with a set dome pressure. Usually, used in deep setting operations.

When flowing pressure of well drops below the dome pressure, dome pressure and valve spring close valve.
Ambient Storm Choke

- Valve reopens when tubing pressure returns above dome pressure. This is done by applying surface pressure above valve, or by running an equalizing prong and equalizing pressure across the valve.
- It can be attached to many types of locking devices.
Wireline Retrievable Surface Controlled

- The Series 10-W Valve is a NC valve, hydraulically controlled from the surface through a control line.
- Should the loss of hydraulic pressure occur, the spring takes over and closes the valve.
- When setting or retrieving this type of valve, an equalizing prong must hold the flapper open.
Wireline Retrievable Surface Controlled

- Equalizing feature - secondary valve.
  - When hydraulic pressure applied (slightly greater than wellbore pressure) the piston begins to move down and opens the secondary valve. This allows pressure to enter the equalizing ports.

- The valve shown is attached to an X lock. It can be fitted to other locking devices.
  - Next slide shows this opening sequence.
Opening Sequence of the Series 10-W Safety Valve

1. **Closed**
   - Secondary Valve on Seat
   - Hydraulic Fluid

2. **Equalizing**
   - Secondary Valve Off Seat
   - Hydraulic Pressure

3. **Open**
   - Hydraulic Pressure
Back Pressure Valve

- Cameron Type H back pressure valve.
- The valve seals off the tubing
  - Repairs can be made.
  - Tree can be installed or removed.
  - BOPs can be installed or removed.
  - BPV can be pumped through if needed.
Back Pressure Valve

- Valve installed in a threaded profile in the tubing hanger.
- Pressures can be equalized, if present, before pulling BPV.
- Use lubricator if installing or removing the valve.
- Valve can handle 15,000 psi differential.
Two Way BP Valve

- Holds pressure from either direction.
- Installed in a threaded profile in the tubing hanger.
- Used when the tree is pressure tested.
- Can withstand differential pressures to 15,000 psi.
Tubing Hanger

- The tubing hanger is an anchor point for the production tubing in the Christmas tree.
  - The tubing hanger is held in place in the tubing head adapter by tubing weight and by hold down pins which are part of the tubing head adapter.
  - Once the hanger is landed the hold down pins are “run in” and tightened.
The seals seal off the top of the annulus.

Tubing hangers contain internal threads or a machined profile for installing a BPV (back pressure valve).

The tubing hanger can be a point of anchor for the control line(s) in the case of a multiple string completion, for the surface controlled subsurface safety valves.
Pressure Testing the Tree

- Rig up lubricator and purge tree.
- Install a 2-way BPV in tubing hanger.
- Install pump discharge line to top of tree or wing. In either case ensure that the correct flanges are installed and any caps removed.
Pressure Testing the Tree

- Prior to pumping into the top of the tree, open the crown swab, surface safety, and master valve.
- Close the wing valve. Then pressure up to the rated working pressure of the tree.
- Check all flanged connections for leaks.
- Break, repair, and re-check any leaking connection again until successful.
Pressure Testing the Tree

- Systematically close and test each valve by itself checking for leaks around stems.
- A good test fluid is clean, solids-free water.
- Do not dry rod the back pressure valve.
This Cameron HLB hand adjustable choke uses a “needle and seat” type of restricting device. This is a manual choke and should be installed on the inside. Hydraulic choke is also used and installed on the outside.
This Cameron hydraulic production choke has a gate and seat design which allows the gate to be reversed as it wears, thus doubling the effective life of the choke.
Completions & Workovers

- Well Completion Operations is the work conducted to establish the production of a well after the production casing string has been set, cemented and pressure tested.
- Workover Operations is the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.
Completions & Workovers

• Brushes and magnets used during wellbore cleanout prior to completion.
How Comp. & WO’S Differ from Drilling

- Solids-free fluids and fluid loss.
- Job may start with well kill.
- Few underbalanced kicks.
- Gas frequently in both tubing and annulus.
- Different kill procedures likely.
- More trips.
- Wellbore tubulars may not be intact.
- Well control equipment varies with job type.
- Little or no open hole.
- May have no slow pump pressures.
- Assured source of hydrocarbons.
How Comp. & WO’S Differ from Drilling

- Operational Characteristics
  - Solids-Free Fluids and Fluid Loss Completion Fluids.
  - Clear, solids-free, completion fluids universally used.
  - Highly permeable and often unconsolidated reservoirs.
  - Ever present fluid loss during completion/workover work.
How Comp. & WO’S Differ from Drilling

- Brines are used when formations are sensitive to damage by invading wellbore fluids.
- Brines are also more likely to invade formation.
- Completion fluids weighted to overcome formation pressures.
- Higher completion fluid weights encourage further fluid losses.
How Comp. & WO’S Differ from Drilling

▪ Workovers Start with a Well Kill
  • Initial completion “brings” on a well.
  • Most workovers begin by killing a live well.
  • There is no well circulating history on the well.
  • There is no annular fluid distribution knowledge.
  • Kill operation involving circulation and constant BHP method are complicated.
  • Kills begin by “bullheading” the tubing with a known fluid sufficient to Kill the well.
How Comp. & WO’S Differ from Drilling

- Few Underbalanced Kicks
  - Any kick is likely the result of a misjudgment, when mud becomes under balance or a casing leak.
  - Kicks on workovers and completions are likely to occur on trips
  - Kicks might occur as the result of gas/liquid swap-outs or unseen falling fluid levels during shutdown periods.
  - The well had a “kill” fluid weight prior to kick. Use Driller’s Method to regain control.
How Comp. & WO’S Differ from Drilling

- Gas in Tubing and Annulus
- On workovers, gas in tubing and annulus is common on rig-up and when releasing packer.
- Condition can come from a tubing or casing leak, squeeze job breakdown, packer failure, or the normal fluid distribution of a packer-less completion.
- These are frequent problems in a workover.
- These are reasons for the workover itself.
- Oil and/or gas on either or both sides requires that kill and cleanup techniques be modified for killing the well.
How Comp. & WO’S Differ from Drilling

- **More Trips**
  - In completions and workover, trips are made for a wide variety of operations. Kicks on workovers and completions are likely to occur on trips.
  - Each operation may call for several trips when trouble-free and more when not.
  - The well had a “kill” fluid weight prior to kick. Use Driller’s Method to regain control.
How Comp. & WO’S Differ from Drilling

- Tubular May Not Be Intact
  - Many factors create tubular failures in productive bores including –
    - Age of tubulars
    - Internal and external corrosion
    - Temperature and pressure of the environment
    - Differential cyclic stresses from pumping
    - Plus wear and tear from tripping and operating downhole tools.
How Comp. & WO’S Differ from Drilling

- More frequent failures
  - These failures show up more in workover than in the drilling –
    - Buckling
    - Burst
    - Collapse
    - Coupling seal
How Comp. & WO’S Differ from Drilling

- Assured Source of Flow
  - A completed wellbore is always open to a source of hydrocarbon flow.
  - Exceptions are when the wellbore is temporarily sealed or plugged off from the pay zone.
  - Even “impregnable” deterrents (packer failure, plug failure or sand bridge giving away) to flow can fail at inconvenient and vulnerable moments.
Porosity is the spaces between the sand grains, 25% - 35%.

Yellow represents space between sand grains which dictates porosity.
Permeability

- Permeability is the ability for fluids to flow between connected pores of a rock.
  - It is an essential property to allow oil or gas to flow into the well instead of being locked into the rock body.
  - Without permeability, no oil or gas will flow to the well, no matter what the size of the pores in the formation.
  - Permeability to oil flow is easily damaged in immediate vicinity of the borehole.
  - This damage may result in a well workover.
Causes Of Formation Damage

- While drilling.
  - Pipe dope, mud solids, mud filtrate, water blocking, clay swelling from freshwater loss.
  - While completing/stimulating.
  - Pipe dope, pipe scale, perforation debris, dirty completion fluid, failed injection stimulation.
Causes Of Formation Damage

- Casing
- Cement
- Perforation
- Skin Damage
- Cement Particles
- Junk from Perforating
- Paraffin, Asphaltines, etc
- Formation Particles
A measure of formation damage commonly is between zero and ten.

Positive Skin Factor – Formation damage exists, can exceed 100.
Negative Skin Factor – Implies the well is stimulated, rarely below –3.
Zero Skin Factor – The well is neither stimulated nor damaged.
• Natural consolidation comes with age. Many GOM sands are very young. Surface tension due to water saturation can help but . . . rock failure leads to sand production.
• Gravel packing allows sand-free production of rocks with low sand strength.
Fracture Stimulation

- Benefits – Fractures bypass damage zone, increases wellbore diameter.
- Fracture is generated hydraulically and gravel packed with high-perm synthetic gravel, steel or ceramic balls.
Formation Damage

- Reduction of permeability in the rock surrounding the wellbore which occurred during drilling, completion, stimulation and production.
- Depth of formation damage is usually less than two feet from the well-bore, this is an extremely critical region.
Formation Damage

- Casing
- Cement
- Perforation
- Skin Damage

Cement Particles
Junk from Perforating
Paraffin, Asphaltines, etc
Formation Particles
Formation damage is usually less than 2 feet from the well-bore.
Water Drive – Associated w/large unbounded reservoirs where drive energy comes from lower water movement, pressure stays high.
Gas Drive – Associated with large unbounded reservoirs where drive energy comes from gas movement from above, pressure stays high.
Combination Drive – Partial water drive, partial gas drive.
Pressure Depletion – Limited and bounded, drive energy comes from the expanding gas, no water. Drive pressure declines as gas is produced.
Types of Completions

- Interface between Wellbore and -
  - Reservoir
  - Open hole
  - Cased hole

- Production Method
  - Pumping
  - Flowing

- Number of Zones Completed
  - Single
  - Multiple zones
Open Hole Completion

- Mostly Used for Thick Competent Rock Reservoirs
  - **Advantages**
    - Entire pay zone is open
    - No perforating expense
    - Reduced casing costs
    - Casing may need to be set before the pay is drilled or logged.
Open Hole Completion

• Disadvantages
  - Well control while completing may be more difficult.
  - Not acceptable for layered formations consisting of separate reservoirs and incompatible fluid properties.
  - Casing may be run with an ACP (annular casing packer)
  - ACP at 3 joints, minimum below packer
  - Allows opening of cementing collar above the packer.
  - Run in low BHP areas.
Typical Stages of Completion

- Production casing is run and the tubing head installed.
- Wellbore fluid is displaced with a non-formation damaging completion fluid.
- Several cased hole log runs are usually carried out.
- The perforating and well testing assembly is run in the hole, the well perforated, and the formation tested.
- After evaluation, debris from the perforating guns and/or formation flow back, may need to be cleaned from the well.
- The downhole completion equipment is then run (gravel pack or slotted liners, etc).
- The production string is then run and the BOP removed. The production tree is installed.
A sump packer is usually used in gravel packing. It is usually set below the perforated interval. Gravel is then pumped down the drill pipe, usually, you have some method that is used as a tattle-tail, to inform you when the gravel has reached its mark.
Q&A #2

Besides gravel packing—what are other uses of the sump packer?

- To set accurate measurements.
- To tie in the tubing strings.
- To do perforating (this helps to decrease perforating shock forces, offers reservoir protection from fluid loss, etc.).
Flowing Well Completions

- Single or Multi-Zone
  - Designed to optimize production from a variety of reservoir environments.
  - Consider the following completions by a major operator in the GOM -
    - Single, gravel packed completion
    - Single, selective gravel packed
    - Dual gravel packed
    - Single gas completion
Flowing Well Completions

- Subsea single gravel packed completion.
- Single completion using a low density proppant water pack.
- Co-mingled completion using low density circulation packs.
- Dual selected gravel packed.
- Many useful completion options and features are possible when using a packer and tubing string.
Completion – Cementing Liner

- The liner hanger and packer were run. When the liner hanger was near bottom, the liner hanger could not be set.
- From experience, we must always run enough liner to set on the bottom of the well.
The liner was set on bottom. The running tool was released from the liner hanger. Cement was then pumped down, followed by the drill pipe wiper plug. When the drill pipe wiper plug landed into the liner wiper plug, the liner wiper plug would not shear out at the pinned 5,000 psi shear out force. Now you have cement from the top of the liner to the bottom, plus 90% of the liner cemented up.
Q&A 3

- The liner wiper did not shear out as expected. You can not circulate since the liner wiper has been plugged off.
- What are you going to do before the cement sets up?
  - You can pressure up and bleed off. Continue to repeat this pressure up and bleed off for several times until the shear pins weaken and shear out.
Coiled Tubing Pack off Installed
Spoolable Completion

CT Gas Lift Installation

- 7-5/8” Casing
- 2-7/8” Tubing
- 1” OD Gas Lift Valves
- Coiled Tubing
- Landing Nipple
Spoolable Completion - Extension

- 7-5/8” Casing
- 2-7/8” Tubing
- Safety Valve
- Hanger
- Packer
- 1” OD Gas
- Lift Valves
- Coiled Tubing
- Landing Nipple

Lower Sand
Spoolable Completion - Extension

CT Gas Lift Mandrel With Connectors
Pumping Wells include –
  • Rod pumping
  • Submersible pumps
  • Plunger lift
  • Pumping wells completed with an open annulus

Gas produced at the surface can be bled off.
Packers are not normally run with submersible pumps.
All pumping systems become less efficient with the presence of gas.
  • Exception - plunger lift pumping systems.
Drilling and Completion Tools

- Alternative Borehole Liner by Petroline Wireline Systems.
- Repair hole or sand/shale problems.
- Well control or drilling problems.
Drilling and Completion Tools

- Expandable Sand Screen.
- Repair hole or formation damage.
- Sand and well Control.
Common Reasons for a Workover

- More common reasons for a workover include -
  - Repair mechanical damage.
  - Stimulate an existing completion.
  - Complete into a new reservoir.
  - Complete multiple reservoirs.
  - Reduce/eliminate water/gas production.
  - Reduce/eliminate water coning.
  - Repair faulty cement jobs.
Common Reasons for a Workover

- **Repair Mechanical Damage** -
  - Repair performed without killing well.
  - Or well killed to perform the work safely.

- **Reasons for Repair** -
  - Failed tubing or downhole tools.
  - Packers.
  - Sliding sleeves.
  - Gas lift equipment.
  - Wireline retrievable safety valves.
  - Failed or failing wellheads.
Common Reasons for a Workover

- Reservoir Stimulation –
  - Introduce a mild acid through perfs. into a reservoir to dissolve acid soluble solids and restore production.

- Performed by –
  - Coiled tubing unit.
  - Snubbing unit.
  - Small tubing unit.
Completing a New Reservoir

- It is done when a well is drilled through multiple productive plays
- Lower zone is finally depleted.
- The new completion might be shifting a sleeve open to allow flow.
- Or, it might require the lower zone be plugged and abandoned before the upper zone is allowed access into the wellbore.
Completing a New Reservoir

Depleted Reservoir

Non-Produced Reservoir

Depleted Zone is Plugged

Packer Set

Re-perforated
Completing an Existing Zone

- Lower depleted zone is isolated with a cement plug prior to opening the sleeve adjacent to the next zone to be produced.
Completing an Existing Zone

- After the cement plug is in place and tested, the sleeve can be opened and the next zone produced.
Re-Completion of Existing Zone

- Production tubing above the depleted zone cut and removed.
- Lower zone isolated with cement plug.
- New completion run in hole next to the reservoir to be produced.
- Upper zone is perforated.
- Production begins.
Re-Completion of Existing Zone

- Lower depleted zone has been isolated with a plug conveyed by either coiled tubing or wireline.
- Plug has been set.
- Plug has been tested.
- Sliding sleeve opened.
- Production then from upper zone.
Completing Multiple Reservoirs

- A dual completion allows for production from two zones simultaneously.
Unwanted Water Production

- Water appears as the lighter fluids are depleted.
- Initial production may contain some water, but O/W ratio goes down as production goes on.
- A temporary solution is to squeeze off affected perforations.
Unwanted Gas Production

- Expanding gas cap forces more gas into oil producing perforations than can be handled.
- This is temporarily remedied by squeezing those perforations.
- Eventually mostly gas will be produced as producible oil is depleted from the reservoir.
Water Coning

- Excess production rates cause water coning and water is pulled up into the perforations.
- Water coning can be slowed by reducing production rate.
- Perfs are then squeezed.
- New perfs above water zone to restore production.
Repair Cement Jobs

- Failing cement job evidence -
  - Pressure on the int. casing string.
  - Presence of cement in choke body.
- Decrease in daily production as surface lines can become clogged with cement.
- Repairing requires
  - Killing the well.
  - Squeezing cement into perforations.
  - Re-perforating the well.
Workover Benefits

- Increase oil and gas production.
- Reduce excessive gas or water production.
- Fracture to improve permeability by opening formation to better connect with well bore.
- Enable highly viscous oil to flow easily.
- Relieve excessive back pressure resulting from plugging formations or obstructions in wellbore surface equipment.
- Replace inadequate artificial lift equipment.
- Repair damaged wellbore equipment.
Well Preparation for Workover

- Prior to Well Kill, consider all items below –
  - Install and test all temporary pipe-work to and from the tree and production or drilling facilities.
  - Prepare workover program detailing kill method and well control devices to be used.
  - All wells in the same well-bay may have to be shut-in downhole and the master valve closed at the surface.
Well Preparation for Workover

- The surface control system for SCSSVs should be locked out of operation.
- Test tree against tubing hanger check valve if high pressure well kill is anticipated.
- Set a wireline plug in tubing if the hanger threads or profile is corroded.
Type of Units to do Workovers

- Conventional
- Concentric -
  - Same as the above, but used small OD tubing.
- Wireline -
  - Braided and electrical.
  - Slick solid wireline.
- Pump Units
- Snubbing -
  - Concerned about OD of tubing being used.
- Coiled Tubing Unit for Workover -
  - Concerned with high friction loss w/ small tubing
  - Snubbing unit for workover job applications
Coiled Tubing & Snubbing WO Applications

- Kill a well by forward circulation.
- Pump nitrogen to bring well in.
- Clean out sand.
- Stiff wireline sets bridge plugs or perforates.
- Run DST’s or production tests.
- Set straddle packers.
- Multiple trips in and out of well.
- Perform work without killing the well.
- Run spoolable completions.
- Run wireline operations: logs, surveys, etc.
- Dump or squeeze cement slurry
- Carry out drilling/milling operations.
Snubbing Packer Into Live Well
Q&A #4

- Calculate the estimated snubbing force required.
- Data -
  - Casing 5 ½” OD; 4.995” ID
  - Tubing 2 3/8” OD; 4.7 Lbs/ft
  - Well Pressure 5,000 psi
  - Estimate Friction Force 3,000 lbs
**Q&A #4**

- Estimated Force =
- $OD^2 \times 0.7854 \times \text{Pressure} + \text{Friction} =$
- $4.9952 \times 0.7854 \times 5,000 + 3,000$ lb. =
- 100,979 lb. of force against the bottom of the packer.
Q&A 4

- Conclusions of this case:
  - Threads would snap at the top of the packer.
  - A blowout caused this well to catch on fire.
Different Methods of Killing a Well

- Driller’s Method.
- Weight and Wait Method
- Concurrent Method
- Volumetric Method.
- Lubrication and Bleed Method.
- Pressure Rise Method of Lubrication and Bleed.
- Bullheading Method.
- Reverse Circulation.
Bullheading

- The sliding sleeve could not be opened by the wireline crew, so the decision was made to bullhead the well.
- Care was taken not to fracture the formation, because other test and simulation for this gas formation were planned.
- After Bullheading, the crew check the well and found only a small amount of fluid flow back. And they assumed that the kill fluid, initial cool, was warming up.
Q&A 5

- After pulling 6,000’ of tubing, this well blew out with gas.
- What should they have done to prevent taking this gas kick?
Q&A 5

- After releasing the packer, they should have done a complete circulation of the wellbore to remove the gas trapped below the packer and tail pipe.
Hot Tips for Killing Wells

- Kicks occur more often during a workover and completion job than they do in drilling.
- When a kick occurs, it can be circulated out faster by reverse circulation.
- When a kick occurs while retrieving the completion string, or excessive swabbing, the completion string should be run to bottom and circulate bottoms up.
Reasons for Leaving a Rathole

- Collect produced formation materials.
- Provides a separation chamber when rod pumping a well with excessive gas.
- Permits running logging tools below production zone.
- Allows tubing conveyed perforating guns to fall below the producing interval.
- Allows packers that can not be retrieved to be pushed to the bottom of the well.
Workover Fluids

- Temperature increases cause the fluid density of brines or mud in wellbore to decrease.
- Workover fluids affect -
  - Killing the well or well control
  - Control excessive loss to formations
  - Clean out trash in tubing and annulus
  - Sand control
  - Packer/Fluids
    - Brine is the most widely accepted method of completion fluids being used today. Settling out barite around tubing above the packer may result in excessive fishing jobs.
Workover Fluids

- Completion fluids are used to exert hydrostatic pressure on the oil/gas production formation.
  - Hydrostatic pressure when greater than formation pressure will prevent the well from flowing.
Completion and Workover Fluids

- Functions of C & WO Fluids.
- A way to kill a producing well.
- A way of cleaning out undesirable solids -
  - Scale.
  - Sand.
  - Paraffin.
  - Junk.
- The ability to perforate the well safely.
Completion and Workover Fluids

- The ability to unload it after the completion/workover job.
- Use fluids that prevent or minimize formation damage so that the well can be returned to maximum production.
- A fluid that when combined with the correct bridging agents will minimize fluid loss to the formation.
- A way to complete the well with gravel packing or sand consolidations.
Completion and Workover Fluids

- A way to increase production by treating with acid stimulation or a fracturing job.
- A way to repair a well by squeezing off an unproductive zone.
- A packer fluid when used with correct additives.
BOP Removal and Xmas Tree Installation

After circulating to condition the packer fluid, the following considerations should be made when removing the BOP stack and installing the production tree:

- Install the surface controlled sub-surface safety valve (SCSSV). Attach the control line and test to working pressure. Run in hole with tubing, attaching control line to tubing with banding material or plastic tie wraps and line protectors. Maintain pressure on control line and monitor while running in hole and spacing out.
Completion / Workover Procedures

- Install tubing hanger and landing joint. Connect the SCSSV control line to top and bottom of the tubing hanger. Test the control line integrity and maintain pressure.

- Drain the BOP stack at the tubing spool. While lowering tubing hanger into BOP stack, keep tubing hanger centered to avoid damage to seals. Pick up additional landing joints with full opening safety valve on top. Insure that all tubing hanger lock down bolts are fully backed out.
Completion / Workover Procedures

- String seal assembly into packer and land tubing hanger. Keep tubing hanger centered while lowering to avoid damage to seals. Monitor tubing pressure while landing seal assembly. Fluid may need to be bled from tubing if the tubing pressure increases while landing seal assembly.
- Run in all tubing hanger lock down bolts and sealing glands and torque properly. Test casing, seal assembly and tubing hanger to required pressure through tubing spool. Remove landing joints and set a back pressure valve in tubing hanger. Test BPV.
Completion / Workover Procedures

- Nipple down BOP.
- Clean and inspect the seal surfaces on the tubing hanger neck. Install top seal ring. Clean and inspect bottom seal of tubing hanger bonnet. Install X-tree. Tighten all studs evenly to energize seals and ring gasket. Re-torque to correct value of all tubing hanger lock down bolts. Pressure test tubing bonnet.
- Nipple up remaining tree valves. Install a blanking plug in back pressure valve. Hydrostatic test tree to rated pressure.
- Pull blanking plug. Pressure up on tree to equalize and open SCSSV. Activate emergency shut down system on tree with remote.
Completion / Workover Procedures

• If required, rig up and test flowlines to test heater, separator and tank.
• If perforating through tubing, displace tubing with completion fluid and perforate. Test lubricator and wireline BOPs as required.
• Test well.
• Close SCSSV and test by bleeding off pressure. Bleed ½ of tubing pressure off SCSSV, observe for leaks. Set BPV and test by bleeding off remaining tubing pressure. Secure tree.
Simultaneous Platform Operations

- Production operations simultaneous to drilling, completion, workover, pumpdown (acidizing or cementing) and major construction activities increase the potential for undesirable events. In various situations, certain drilling operations require production shutdown.
- Simultaneous activities should be coordinated through joint planning efforts of drilling, production and construction supervisors.
Simultaneous Platform Operations

- Critical areas of simultaneous operations are defined as areas in which explosives or ignitable mixtures are present or potentially present due to the release of flammable gases or vapors.
- During simultaneous operations, care should be taken to avoid potential sources of ignition and damage to equipment in such areas.
Critical Workover Areas

- Wellhead
- Mud tanks, mud pumps, and mud processing areas
- Degasser
- Production areas
- Producing oil or gas wells
- Equipment for field processing and handling of oil and gas storage tanks
- Gas/oil/water separation vessels
Critical Workover Areas

- Gas vents and relief valves.
- Automatic custody transfer installations.
- Gas compressors and pumps handling gases or volatile liquids.
Simultaneous Drilling/Workover & Prod. Operations

- All personnel should be familiar with the use of the Emergency Shutdown System (ESD).
- ESDs should be installed at the rig floor, at the main quarter’s exit, at stairway exits from the main deck, at each ramp exit, each helicopter deck and at each boat landing.
- Subsurface safety valves should be closed on all wells in which heavy lifts or derrick skidding operations are taking place above.
- The casing annulus pressure should be checked daily on completed wells.
Surface Safety System

- Surface Safety Systems include –
  - Subsurface Safety Valves
  - Hydraulic Control Panel
  - Control Lines
Surface Safety System

- Subsurface Safety Valves
  - There are two types of subsurface safety valves. The old type is controlled by the flow rate through the tubing and is not connected to the surface. All wells completed since January 1, 1980 have the newer type which is controlled by pressure supplied from the surface (SCSSV).
  - The valve must be located at least 100 ft. below the mud line. The function of the valve is to block upward flow through the tubing when an emergency condition exists.
Surface Safety System

- **Hydraulic Control Panel**
  - The opening and closing of the SCSSV is controlled through the hydraulic panel. On the front of the panel there are hand-operated valves which can be used to open and close the SCSSVs. The SCSSV can be closed by turning the control valve to the TEST or OUT-OF-SERVICE position.
Surface Safety System

- **Control Lines**
  - Hydraulic pressure is carried from the devices in the hydraulic panel to the SCSSVs through stainless steel tubing called a control line (1/4” or 3/8” OD). There will be either one or two control lines for each SCSSV, depending on the type of valve. The control line enters the well through a small needle valve at the tree. This line connects the hydraulic control unit on the surface to the SCSSV in the tubing string.
Surface Safety System

- Flag and Tag/Lock-Out
  - For the purpose of protecting personnel and equipment from the dangers of electricity, pressure and hazardous liquids during normal offshore operations, the following procedures are recommended whenever a safety device is taken out of service:
    - By-pass the safety device indicator and install red OUT-OF-SERVICE tags on the indicator. Isolate safety device from pressure sources. Bleed the source down to atmospheric pressure.
Surface Safety System

- Flag safety device with red flagging tape.
- Disassemble and perform maintenance or preventive maintenance.
- Only the original installer of the red OUT-OF-SERVICE tag and red flagging tape should be authorized to remove them. Once work is complete, take care to remove the tag and flag.
Surface Safety System

- The surface safety system includes the -
  - Surface devices
  - Tubing
  - Pneumatic pressure
  - Panels
- The working relationship of these devices help prevent injury, pollution of the environment, and damage to the equipment on the platform.
Surface Safety System

- Pneumatic Surface Safety Valve
- Hydraulic Blow-down Valve
- Fusible Plug
- Emergency Shut-in Valve
- Instrument Gas or Air Control Line
- Low Pressure Monitoring Line
- Hydraulic Surface Safety Valves
- Manual 3-Way Valves
- Remote Controlled Subsurface Safety Valves

Sales Line
Surface Safety System Devices

- Surface Safety System Devices Include –
  - Pressure, Flow, Temperature, or Fluid Level Sensors
  - Relays
  - Flow Valves

- Sensors
  - Sensing devices detect abnormal pressure, flow, temperature, or fluid levels and activate relay devices which in turn close a safety valve and activate an alarm.
Surface Safety System Devices

- Relays
  - The CRBBM (control relay, block and bleed manual) is the most common type of relay device used. They are located at various points within the system and are used to shut-in a vessel or well when an abnormal condition occurs.
  - The CRBBM is normally closed and controls the automatic closing and manual opening of the equipment to which it is attached.
Shutdown Valves

- Normally closed valves are held open by pressure. The primary shutdown valves are located at the tree, but others may be located on pipelines, headers, wellheads, fuel supply lines, suction lines, and other places which require shut down in the event of an emergency.
Blowdown Valves

- Blowdown valves are located on compressors and fired vessels and are used to vent the pressure from a process station at the shut-down.

- Fire Loop System
  - The fire loop system is an emergency support system which operates automatically when a fusible plug melts.
Emergency Shutdown System (ESD)

- The ESD provides for the automatic shut-in of all wells on the platform. The ESD has manual control stations at various locations throughout the platform.
Emergency Shutdown System (ESD)

- Emergency Shutdown Valves
  - A pneumatic actuator valve is installed on a secondary master valve on the tree and serves as a surface safety valve.
  - The SSSV is a way to shut in the well below the surface.
  - The control panel supplies hydraulic pressure to operate SSSV and a ESD thus a separator on location supplies the pneumatic pressure.
Emergency Shutdown System (ESD)

- Fusible plugs are situated where fires may occur – the wellhead and separator. These melt at a low temperature, releasing supply pressure, and shut the system down.
- Pressure monitors, both high and low sensing, are situated on the flow-line downstream of the tree and on the sales line.
- ESD valves are located in strategic locations such as boat landings (offshore installation), location entrance/exit, helicopter pad, and upper decks.
Emergency Shutdown System (ESD)

- Wells completed where wireline work will take place are equipped with a SSV capable of cutting slickline and braided line.
- The SSV uses hydraulic pressure to hold the valve open.
- The spring and gate in the valve is capable of cutting wireline as large as 7/32”.

Surface Safety Valve

Lockout Cap
Fusible Cap
Stem
Thread Protector
Cylinder
Piston
Packing Section
Spring
Bonnet
Valve Body

Emergency Shutdown System (ESD)
Hydraulic Surface Safety Valve

- Wireline
- Bleed-Off Valve
- To Wireline Unit
- Swab Valve
- To Flowline
- Actuator
- Wireline Cutter Gate Valve
- Master Valve
- Wireline Tool String
- Emergency Situation Cutting Wireline
Causes of Kicks

- Workovers and Completions
  - During a workover, a kick can occur for many reasons.
  - A kick is any unwanted intrusion of formation fluids into the wellbore.
- If not detected early and handled properly, it could result in a surface blowout.
Causes of Kicks

- Main causes of kicks during workovers –
  - Failure to keep hole full during trips
  - Swabbing
  - Insufficient fluid weight
  - Loss of circulation
  - Surging
  - Abnormal Pressure
  - Annular gas flow after cementing (Channel Job)
Causes of Kicks

- Failure to Keep Hole Full During Trips
  - As a workstring is pulled from the hole, the fluid level in the well drops due to the displacement of the workstring.
  - As the fluid level drops hydrostatic pressure decreases.
  - Fill-up every 5 stands or when the hydrostatic pressure drops 75 psi.
Causes of Kicks

- If the hydrostatic pressure of the workover fluid decreases below formation pressure, formation fluids will flow into the well.
Causes of Kicks

- Using a Trip Tank
  - Most reliable means of measuring/monitoring hole fill-up.
  - Calibrated in half or quarter barrel increments.
  - A crew member assigned to monitor/record volume changes in the trip tank during trips in and out of the hole.
  - The volumes reported on regular basis to driller are compared to actual/calculated pipe displacement values.
Causes of Kicks

- Calculated displacement volume, either pumped in or otherwise enter hole via gravity, should be seen coming out of hole when the work string is tripped back in.
- If the volume exiting the hole during a trip is greater than calculated, the well may be flowing.
- If the volume is less than calculated, the well is loosing fluid, or possibly the cement has failed, or tripping too fast.
Causes of Kicks

- Monitoring Displacement
  - The trip tank must be calibrated to measure the change in trip tank level. Then measure the tank for HEIGHT, WIDTH, and DEPTH (inches). Convert these measurements of the tank volume to inches per bbl and bbl per inch as shown below:

  **Tank Volume in BBL**
  \[ \text{Height}_{\text{Feet}} \times \text{Width}_{\text{Feet}} \times \text{Depth}_{\text{Feet}} \times 0.1781 = \text{Volume}_{\text{bbls}} \]

  **BBL per Inch**
  \[ \frac{\text{Tank Volume}_{\text{bbl}}}{\text{Tank Height}_{\text{inches}}} = \text{Bbls}/\text{Inch} \]

  **Inches per BBL**
  \[ \frac{\text{Tank Height}_{\text{inches}}}{\text{Tank Volume}_{\text{inches}}} = \text{Inches}/\text{bbl} \]
A vertical cylindrical tank can be used as a trip tank. The dimensions required are DIAMETER in inches, and the HEIGHT in feet.

**Tank Volume in BBL**
(Tank ID^2 ÷ 1029.4) x Height \(\text{ft}\)

**BBL per Inch**
Tank Volume bbl ÷ Tank Height inches = Bbls/Inch

**Inches per BBL**
Tank Height inches ÷ Tank Volume inches = Inches/bbl
Causes of Kicks

- Trip Tank and Continuous Circulating
  - As pipe is pulled from the well, the level in the trip tank decreases as the pumps pull fluid from the tank and fill the hole at the same time.
  - The volume of fluid pumped into the well should be monitored on a continuous basis using the calculated rate of fluid entering the well vs. actual returns. Any discrepancies throughout operations should be documented for reference.
Causes of Kicks

• Anytime pipe movement stops, the level in the trip tank would remain constant if the well was not flowing.
• A gain in pit volume with pipe not moving indicates the well is flowing.
• This arrangement is adaptable to a coiled tubing unit, a snubbing unit, or a small tubing unit.
Causes of Kicks During Workovers

- Swabbing is affected by –
  - Pipe Pulling Speed and Acceleration
  - Annular Clearances
  - Workover Fluid Properties
  - Swabbing is common in completions and workovers because –
    - Tools like packers have sealing elements which may be partially expanded while being pulled. This reduces the fluid bypass area around the tool.
Causes of Kicks During Workovers

- **Warning signs of swabbing**
  - A warning sign of possible swabbing is that the hole is not taking the calculated fill-up volume.
  - When swabbing is detected, the trip should be immediately stopped and the well monitored for flow.
  - If flow is detected the well should be shut-in and tubing and casing pressures should be measured at frequent intervals, then recorded.
  - If no flow exists and the inadequate fill-up volume trend indicates swabbing, then RIH (run in hole) with the work string to TVD and circulate bottoms up.
Causes of Kicks During Workovers

- Insufficient Fluid Weight
  - Should the fluid weight decrease due to dilution from produced fluids or accidental dilution on the surface, a kick is liable to occur.
  - Check fluid weights continuously for proper value during work overs and recorded data collected.
Causes of Kicks During Workovers

- Higher Brine Densities
  - Have more affinity for fresh water.
  - Are more prone to cutting by the contamination from humidity making it necessary to cover pits on occasion.
  - Increase in density equals increase in cost

- Reconditioning fluids beyond normal fluid maintenance is an added avoidable completion/workover cost.
Causes of Kicks During Workovers

- Loss of Circulation
- Loss of circulation can cause a well kick.
- When fluid is lost it can be to -
  - The producing formation
  - Formation fractures
  - An upper zone that has been depleted, and the well has a UGB.
Causes of Kicks During Workovers

- Underground Blowouts (UGB)
  - This well control situation is difficult to contain.
  - UGBs can lead to severe damage to the producing formation.
  - UGBs may lead to big production losses.
  - UGBs require specialized techniques to handle.
- UGBs need specialized companies and personnel i.e. Wild Well Control.
Kick Conducive Operations

- Unseating Packers
- Packers for gravel-packed completion are left in the hole.
- A workover involves unseating or pulling the seal assembly from several packers, most have formation fluids trapped below them.
- Fluids accumulate in the dead space between the bottom of the packer rubber and the topmost opening in the tubing extension below the seal nipples.
If the well has not previously been completely killed on the tubing side, then the entire rat-hole below the packer may contain formation fluids.

- If the well makes gas, the surface volume will be trapped gas because of migration.
- When the packer is unseated or the seal nipples pulled above the packer bore, the trapped gas escapes into the annulus and starts migrating up the wellbore.
Kick Conducive Operations

- The release of the gas below the packer does not threaten to make the well flow at the time of release because the bottom hole pressure does not change significantly.
Other Kick Conducive Operations

- Perforating opens the cased wellbore to formation pressure and exposes the formation to a low-viscosity solids-free fluid.
- This does not produce a well control problem, per se, but if you are under balanced, the well will tend to flow.
Other Kick Conducive Operations

- The wellbore is more conducive toward well flow after perforating. It may or may not flow depending on the control fluid weight when the well was perforated.
- If the well is induced to flow on perforating it will be produced for cleanup and then possibly put on long-term production.
- An unplanned well flow might occur when perforating or when the first trip is made out of the hole after perforating.
Other Kick Conducive Operations

- Tripping with Fluid Losses
  - Fluid losses are common in workover and completion operations. The rate of such whole fluid loss varies with –
    - Formation permeability.
    - Fluid viscosity.
    - Degree of overbalance.
    - Pipe-induced pressure surges
    - Pressures caused by circulation of the wellbore.
  - These losses can be very costly and damaging if not carefully monitored.
Other Kick Conducive Operations

- Control fluid loss to 10 to 20 bph when pulling out of hole (POOH), based on:
  - Stage of the completion.
  - Formation sensitivity.
  - The difficulty of achieving the desired fluid density without undesired formation damage.

- If the loss rate is acceptable and consistent while tripping, monitoring the proper fill on the way out is straightforward.
Other Kick Conducive Operations

- Despite the numerous differences between drilling and completion work, the warning signs that indicate an actual or potential well control problem while tripping are unchanged.

- We still watch for a flow, a pit gain, or the hole not taking the right volume. All of these conditions are much easier to assess if the fluid loss rate is known and stable.

- Unfortunately the loss rate can vary with pipe movement itself and with just time.
Other Kick Conducive Operations

- Fishing
  - Efforts to recover tools or pipe lost in the hole can add to the likelihood of a kick or the difficulty of controlling one in several ways -
    - More trips
    - Fish swabbing
    - Limited circulation is possible with a fish in the hole and sometimes not possible at all.
Other Kick Conducive Operations

- Fishing is more risky in workover and completion operations.
- The fish, if it includes a packer or a multi-way circulating port, can add greatly to surge and swab pressures.
- If circulation is not possible or the fishing tool cannot seal on its top, the fish becomes a barrier to full-hole circulation.
- The length of the fish and clearance around the fish, dictate the extent of the barrier effect.
Other Kick Conducive Operations

- If the fish is long, or fishing by wireline, the hole may be uncirculated for extended periods, during which formation fluids and solids may be settling around the fish. This decreases clearance between the fish and casing making it more difficult to retrieve.

- Gas in the hole can migrate during trips and cause well flow.

- A kick may thus occur at that worst possible time - when the work string is off bottom (the further up the hole the more severe impact it will have) or out of the hole.
Other Kick Conducive Operations

- Repetitive tasks tend to develop complacent crew members.
- One cannot afford to ignore well control issues at any time.
- Always think down hole.
Other Kick Conducive Operations

- Cleaning Out Fill
  - Circulating to remove fill from the active wellbore occurs frequently in completions and workovers.
  - It is routine to remove loosely packed sand or debris, following perforating, testing, or gravel packing operations.
  - This fill hinders the running of seal nipples into a packer.
Other Kick Conducive Operations

- The fill is cleaned out by reverse circulation under a closed annulus while lowering the workstring fitted with appropriate cleanout tools.

- The fill may result from:
  - Sanding up of the well while on production.
  - From a kick that brought formation solids into the wellbore.

- When fill is cleaned out, usually reverse circulation is the choice method (short way). If the well is circulated by forward circulation (long way) then you may encounter unexpected oil or gas pockets which may require a choke.
Other Kick Conducive Operations

- When the bit or muleshoe breaks completely through the fill it may turn out to be a bridge a long way off bottom -
  - Under these conditions a long column of formation fluids can exist below the bridge.
  - The hydrostatic pressure available above the bottom of the workstring may be inadequate to hold the formation pressure.
  - The effect is a kick, off bottom with the rat-hole full of gas and oil.
Other Kick Conducive Operations

• If a breakthrough occurs near enough to the perforations that the well is considerably overbalanced, the fluid level in the annulus can drop suddenly and allow the well to kick.
• Either way, there is an off-bottom kick with complicated losses.
Warning Signs of Kicks

- While Circulating –
  - Flow increase without an increase in pump rate.
  - Well flows with the pump off.
  - Pit level increase.
Warning Signs of Kicks

- Unintentional kicks –
  - Indicators deal with flow from formation into the wellbore.
  - One type of workover is to plug and abandon one zone and start production from another.
    - Set bridge plug above the zone to be abandoned
    - Place cement on the bridge plug.
- A cement plug may be placed across perforations.
Warning Signs of Kicks

- **Cement Plug Considerations**
  - Always check well for flow after waiting on cement to cure.
  - Formation fluids may contaminate the slurry and stop it from setting. Gas can then channel its way through the cement.
- Another cement plug must then be run over the failed one.
- Additionally, additives should be mixed with the cement to minimize or inhibit contamination.
Warning Signs Prior to or With A Kick

- Gas/Oil Well Workover
  - Gas cutting back the fluid weight warns that gas has come into the well.
  - Gas will reduce the density of the workover fluid as it expands reducing hydrostatic pressure as gas migrates.
  - Never ignore fluid surface gas break out.
Warning Signs Prior to or With A Kick

- Oil Well Workover
- Oil presence in the workover fluid will reduce hydrostatic pressure of the fluid column.
- Always ‘check out’ any show of oil at the surface.
Warning Signs Prior to or With A Kick

- While Tripping
- Bottoms up circulation
  - Always have one bottoms up circulation prior to beginning the trip.
  - Record returning fluid density every 5-10 minutes or as required.
  - Note any show of formation fluids.
  - After completion of bottoms up circulation, keep well static until well is dead before trip out begins.
Warning Signs Prior to or With A Kick

- Well Flowing While The Pipe Is Stationary (Tripping In)
  - Crews can get so involved with the business of tripping in the hole that the hole goes unmonitored. Always ensure that fluid displacement while pipe is stationary or running pipe matches calculated displacement volume.
Inadequate Hole Fill During Trips

- Best indicator of problem while tripping is fill-up volumes that don’t correspond, within reason, to calculated values.
- Stop trip whenever this occurs and monitor for flow.
- Shut-in the well if necessary.
- If fill-up trend discrepancy continues, stop, return to bottom. Then prepare to shut-in, and circulate the well on a choke.
Warning Signs Prior to or With A Kick

- When tripping in, monitor fluid volume being returned due to displacement. If the volume returned is greater than calculated displacement, be prepared to shut-in.
Kick Containment

- **Shut - In Procedures**
- **On Bottom Circulating, Surface Stack –**
  - Contain the kick and keep the influx volume to a minimum.
  - The shut-in procedure may vary because of -
    - Type of well servicing unit (Coiled tubing, snubbing, or conventional workover rig) in use.
    - Operation in progress at the time of the kick.
Kick Containment

- Due to the limited wellbore volumes it is imperative to shut the well in quickly.
Kick Containment

- Example Shut - In Procedure while circulating or tripping –
  - With the pump(s) running, pick up off bottom to pre-determined space-out height to ensure a tool joint is not across the stack.
  - Stop the pump(s) and check for flow.
  - If flow exists, shut-in the top set of pipe rams.
  - Gain casing access by opening the appropriate valve on the choke line side of the stack.
Kick Containment

- Open the valve downstream of the choke.
- If tripping ensure an IBOP and a FOSV is available.
- Record SITP and SICP and estimate pit gain.
- At this point, the annular preventer, if one is installed, could be closed and the top pipe rams opened.
Kick Containment

- Tripping Tips –
  - Industry requires that crossovers be on the floor with proper connections so the FOSV and IBOP can be installed onto any component of the workstring.
  - Know the closing volumes of the preventers used.
  - Visually inspect the BOP stack and choke manifold for leaks shortly after shut-in.
  - Have shut-in pressures monitored frequently until pressures stabilize. Recording pressures in regular intervals.
  - Have shut-in pressures recorded as necessary.
Kick Containment

- Gas Migration and Stable SICP
  - If gas is present, then gas migration is certain.
  - Unless a pressure history has been recorded it might not be possible to determine a realistic “stable” SICP.
  - Monitor and record SICP immediately after shutting in a well on a regular basis until well stabilizes.
  - An “accurate stable” SICP must be used for workovers.
Kick Containment

- Too high a chosen SICP and the well may be lost by formation fracture or underground blowout.
- Too low a chosen SICP and the well may never be killed to be able to work it over properly.
- The true stable SICP can be found from the curve on the following chart.
Kick Containment

- The stable point is at the end of the initial flow based on the formation characteristics.
- Pressure stabilization is the point when gas migration begins.
Shut-In Pressure

- Total pressures on either side of the well equals formation pressure.
- Any difference shown on gauges at surface is hydrostatic pressure to be replaced to balance formation pressure.
Shut-In Pressure

- In a pre-completion or work over, there is no SITP, as the kill effort was successful.
- The lack of pressure on the tubing indicates the fluid density in the tubing at least balances formation pressure.
- A SITP with a kill fluid could indicate a trapped pressure.
Shut-In Pressure

- Sources of trapped pressure include –
  - Pumping into a shut-in well.
  - Surface pressure increase caused by migrating gas.
- When shut in pressures are initially recorded following stabilization, confirm that these pressures are accurate.
Trapped Pressure - Bleeding

- Procedure to detect presence of trapped pressure –
  - STEP 1 Bleed a small amount of fluid through choke (1/4 to 1/2 bbl) - surface pressures will initially decrease, build, and then stabilize.
  - STEP 2 Observe SITP - if the SITP stabilized at a value less than the previously observed stable pressure, no trapped pressure was detected.
Trapped Pressure - Bleeding

- STEP 3 Bleed another small amount of fluid through the choke and once again observe the stabilized SITP.
- STEP 4 True, or accurate, SITP is when consecutive and identical values appear on the tubing gauge - in most cases in completions and work overs, the SITP should bleed to 0 psi.

- Use this procedure to detect the presence of trapped pressure and to remedy the situation if any is found. Perform this only after surface pressures have stabilized.
Live Well Kill Techniques

- Bullheading
  - Bullheading (pumping only) is common for killing live wells in workover situations.
  - Use a surface choke to regulate pumping pressures if formation fracture is a concern.
Live Well Kill Techniques

- When an abnormally low pressurized formation will not support a column of fluid to the surface. Then kill the well by pumping a sufficient fluid density to slightly overbalance the formation pressure.
- Pump more kill fluid in well periodically, monitor losses via trip tank.
- Maintain controlling fluid level if tubing is pulled from well.
## Bullhead Kill Sheet

### Daily Recorded Operational Field Data

<table>
<thead>
<tr>
<th>Location:</th>
<th>Well #:</th>
<th>Cow Creek</th>
<th>Tree Area</th>
<th>Surface Volumes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Casing</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Casing</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Bullhead Well Control Checklist

- **Bullhead PUMP RATE TO KILL WELL**
  - Pump No.: (n)
  - Desired Kill Rate (bbl/min)
  - Pump Output (bbl/min)
  - Pump Strokes (Per Min)
  - Pump Presure (psi)

- **Bullhead Depth to Kill Well**
  - Depth to Calculate Kill Fluid Density
  - Depth to Kill Well

- **Tubing Data for Volume, Strokes and Time**
  - Tubing OD (in)
  - Tubing ID (in)
  - Tubing Capacity (bbl/mi)
  - Tubing Length (ft)

- **formation**
  - Formation Pressure (psi)
  - Maximum Fluid Weight (gpm)
  - Surface to End of Tubing

- **Anular Fluid Annular**
  - Fluid Weight (rpm)
  - Surge to Perforations

- **Bullhead Schedule Chart**
  - Bullhead Volume (bbl)
  - Bullhead Strokes (strokes)
  - Bullhead Minutes (mins)
  - Bullhead Beginning (psf)
  - Bullhead Ending (psf)

### Perform Calculations on Next Page Before Completing Database & Staring Bullhead Operations.

**Reference Additional Values When Kill Fluid Is At Poets in Overdisplace.**
Live Well Kill Techniques

- Lubricate and Bleed
  - Consider lubricate and bleed method when bull heading technique is not feasible:
  - When perforations are plugged.
  - Excess fluid loss to the formation may damage productivity.
- Lubrication will only remove gas.
Live Well Kill Techniques

- Circulation Methods
  - Reverse circulation is used for killing live wells.
  - A circulation path must exist between tubing and annulus to reverse.
  - A wireline is used to perforate the tubing above the packer if this method of well kill is used.
  - Alternatives to perforating are to pump through -
    - Gas lift mandrels.
    - Sliding sleeve (if available).
Coiled Tubing/Snubbing Units

- Coiled tubing or snubbing units are used to kill wells.
- Snubbing units are used as a pulling unit to unseat the packer and to establish a path of communication between the tubing and the annulus.
- Coiled tubing can be run through the tree and tubing string and used to circulate hydrocarbons from the tubing and kill through the tubing string.
Live Well Kill Techniques

- Problems with Multiple Completions
  - Selecting a project specific method suitable for retrieving the seals from the packers which will allow tubing and annular communication.
  - If a workover cannot be done with a wireline unit, then all the producing zones must be killed before the tubing can be pulled.
Killing a Producing Well

- Pre-Recorded Information
  - Prior to any work performed an accumulation of pertinent data must take place. Information vital to many operations are as follows –
    - Wellbore Configuration
      - ID/OD, burst, collapse, tensile strength, and length of the tubing string to be worked with.
      - Extent of the perforations (top and bottom of perfs) and noting both measured and true vertical depth.
Killing a Producing Well

- Condition of the perfs: Is the well capable of flow or is there perforation damage?
- Depth of tubing nipples, side pocket gas lift mandrels, sliding sleeve(s), and any previously encountered tight spot.
- Depth and type of the packer.
- Casing ID and burst limit.
- Type and anticipated density of the packer fluid if any is present.
- Wellhead pressure rating.
Killing a Producing Well

- Information vital to many operations are as follows –
  - Formation Pressure: based on last known bottom hole pressure survey.
  - Fracture Pressure: estimate of fracture (information best gathered from reservoir engineering).
  - Maximum Allowable Casing Pressure: estimation based on either fracture pressure or estimated casing burst pressure (previously discussed).
  - Produced Fluids: Formation water and hydrocarbons.
Well Control Problems

- Choke Washout
  - A choke washing or cutting out is difficult to detect initially.
  - The first indication is its failure to seal when fully closed.
  - The need to make frequent choke adjustments during a kill operation when this should not be required.
Well Control Problems

- The solution is to go to another choke. If another choke is not available close in and call supervisor.
- The faulty choke should be isolated by upstream and downstream valves on the choke manifold.
- After the well is dead, the faulty choke should be -
  - Repaired
  - Tested
  - Put back into service
Well Control Problems

- Plugged Choke
  - A plugged choke will show an increase in casing pressure followed by an increase in pump pressure - both of which can rise sharply.
  - This sharp increase can cause formation breakdown.
  - When choke plugging is noticed, shut the pump down immediately.
  - A plugged choke may show a loss of returns and pressure increases.
Well Control Problems

- Change over to another choke. Isolate the plugged choke by upstream and downstream valves.
- Once the well is dead, clean out the plugged choke, usually performed by a choke specialist.
Well Control Problems

- Workstring Washout
  - A washed out workstring can be hard to detect.
  - As the string washes out, pump pressure gradually declines but only a little at a time and it often goes unnoticed.
  - The most common occurrence is a crack in the box at a connection or a crack in slip area of the workstring.
  - Floor hands must be aware of the telltale signs of washing out.
Well Control Problems

- When noticed, the joint in question must be removed from service. Follow procedures for removing a faulty joint.

- Another indication of a washout is the premature return of kill weight fluid whenever a lighter fluid is being replaced by a heavier one.
Well Control Problems

- **Plugged Workstring**
  - When a workstring plugs the pump pressure will noticeably increase without an increase in the casing pressure.
  - Casing pressure may decline with a decrease in return flow.
  - If this takes place, stop the pump and shut the well in.
  - Try to free up the obstruction in the workstring by pressuring up on the annulus but do not damage the wellbore or formation.
Well Control Problems

- If the obstruction cannot be removed by pumping, then volumetric well control should be started. This method to be used is when dealing with gas.
- So that conventional well control can once again take place.
Well Control Problems

- **Hydrates**
  - Hydrates, or frozen gas or ice plugs, can form when the right mixture of gas, water, and low temperature is present.
  - The mixture can literally freeze, or become solid, even at temperatures above the freezing point of water.
  - This phenomena is common to gas fields that produce a fair amount of water, especially in the winter time.
Well Control Problems

- Hydrates have formed in the cavities of valves and blowout preventers making them inoperable.
- Preventing hydrates is easier than curing the problem.
- Salt-saturated or oil-based fluids can be used as well as a mixture of glycol and anti-freeze.
- Thawing hydrates requires heating the hydrate where it forms. This can be difficult, especially in deepwater subsea installations.
Problems While Circulating

- Always check BOTH the pressures on the tubing and the casing gauges before making a change.
- After making a change at the choke be sure to wait 2 seconds/1000ft. To ensure that all changes are visible on the casing and tubing gauges.
Problems While Circulating

- If casing pressure is not increasing, then the problem is on the workstring side and opening the choke increases the influx.
- If both gauges are reading identical pressures, it is likely on the casing side.
- If just the pump pressure is reacting, it is on the workstring side.
Problems While Circulating

- Hole in Tubing String
  - Communication between the tubing and casing can be present because of -
    - Holes in the tubing.
    - Leaking gas lift equipment.
    - Leaking sliding sleeves.
    - A leaking tubing hanger.
    - A leaking previously installed wireline pack-off.
Problems While Circulating

• Communication between the tubing and casing makes bull heading more difficult because you are pressuring up on both the tubing and casing.
Problems While Circulating

- Solutions for Communication Issues
  - One way is to install a pack-off, which can be installed either via wireline or coiled tubing.
    - First step: locate the area or areas of communication and then determine the feasibility of installing a pack-off.
    - Using a ponytail tool attached to a small tool is used to locate the depth of the hole.
    - A tubing stop can be installed below the hole in tubing and an upper and a lower packoff can become a straddle pack to isolate the hole.
Completion and Fishing

- You are in the middle of the jungle in South America – and you have no fishing tools to fish out the wash shoe.
- A 5” hydraulic set right hand release packer with bi-directional slips was run inside the washover shoe and set inside the fish. The packer was plugged at the bottom.
Completion and Fishing

- Fresh water was used to set the packer after going inside the fish. The fish came free after several impacts with the oil jars.
- The washover shoe was laid down on the rig floor. The wrenches were used to hold the fish and the packer was released by right hand rotation.
This is a single string multi-zone (3 zones) water injection well.

It is not hard to get the Waterman water regulator set to inject the correct amount of desired water into each zone.
The bottom three packer are push-in cup type packers-with opposite pressure setting sealing cups.
The problem is when you start trying to retrieve them from the wellbore.
Dual String Gas Lift

- This type of completion is run to allow both strings to be placed on gas lift with a single space (the annular is for gas lift injection).
- Usually the long string is run first, then landed and hung off.
Next, the short string is run with an automatic jay latch in sub to anchor the short string.

The short string is spaced out and put in tension by pulling up against the latch in the top of packer.
Dual String Gas Lift

- Next the drilling fluid is replaced by completion fluid by pumping down the casing and out the short string.
- A ball is dropped and the dual packer is set.
Dual String Gas Lift

- Next, we pump down the long string and circulate completion fluid down the long string and out the short string.
- Drop ball and set single packer. Now the short string is anchored by the automatic jay latch.
Dual String Gas Lift

- To release, weight is set down on the short string and straight pick up releases the short string from the packer.
- Sometimes the well will flow naturally, but when the well is placed on gas lift, communication occurs between the short string and the annulus.
Learning Objectives

- You learned -
  - The reasons why a well needs to be worked over.
  - The benefits derived from working a well over.
  - To prepare a well completion.
  - To design a completion for the type of reservoir.
  - The types of well completion equipment.

- You also learned -
  - The surface completion equipment needed.
  - The downhole completion equipment needed.
  - You reviewed how to control and kill live wells.