Complications

Learning Objectives

- You will learn to detect changes that deviate from established trends.
- You will learn how to respond to problems such as:
  - Pump problems
  - String problems
  - Hole complications
  - Choke problems
- You will also be presented with information regarding stripping and general snubbing.
Complications
Well Control Complications

Overview

- Very few well control activities operate according to plan.
- Thus, you should be familiarized with complications that may arise during a well control operation.

- The best way to know how to solve problems that may occur is to always keep good records of developing trends and events.
Well Control Complications

Overview

- Problems developing during well control operations can quickly lead to uncontrollable situations.
- The crew MUST communicate any changes from what is established or expected.
- Critical to monitor:
  - Pumps and pump rate
- Circulating pressure
- Choke pressure
- Flow and type of fluid from well
- Pits
- Equipment involved in pressure control
Well Control Complications

Overview

- Documentation is very critical.
  - Key to determining a developing problem.
  - Key to finding the solution(s) to the problem.

- Changes in shut in, circulating or choke pressure must be noted.
- The sequence of how a problem develops is key.
Well Control Complications

Overview

- The sequence of how pressures change is crucial. If first noted on:
  - *Circulating pressure* – problem usually is on pump and string side of U-tube.
  - *Choke pressure* – problem usually from choke to bottom of well.

*Question:* Does the pressure change also reflect to the other side of the U-tube?
Well Control Complications
Well Control Complications

Overview

- Pressure changes can influence BHP, pressure on casing shoe/weak zones.

- A sudden increase in choke pressure may indicate plugging downstream of choke and require pump shutdown.
Hole/Washout in Tubing

- Very difficult to detect during well control.
- If developed prior to shut-in:
  - SIDPP may be higher or equal to SICP when kick is above washout.
    - If float is used: Pressure on string (SIDPP).
- If develops during kick circulation:
  - If washout occurs, circulating pressure maintaining BHP not reliable.
  - If not detected, circulating pressure drops and choke operator incorrectly adjusts choke.
    - Higher choke pressures may lead to formation leakage/fracture complications.
Plugged Bit

- Can occur when large quantities of chemicals and weight material are used. Large chunks may form and totally or partially block the nozzles or circulating ports in the bit/downhole tools.
  - Total blockage will result in a rapid increase in circulating pressure and decrease in choke pressure.
    - Shut down pump, shut well back in.
Plugged Bit

- Partial blockage will result in an increase in circulating pressure. If pump maintains constant speed, choke pressure remains constant.
  - Consideration should be given to shutting the well in and using pump start up procedure to establish a new circulating pressure.
  - Or, continue pumping and use new increased value as circulating pressure (if pump does not exceed pop-off.).
Shut-In Pressures

- If shut-in pressures are too high or low, they can cause complications.
- Pressures and time of kicks should be recorded frequently until they begin to stabilize.
- Formation characteristics, pressure, depth, fluid type, and influx type all affect the amount of time that is required for the wellbore to equalize and pressures stabilized.
Shut-In Pressures

- It is impossible to estimate a timeframe for shut-in pressures to stabilize.
- Kill weight fluid is calculated from the recorded pressures.
- In addition, annular pressure is maintained while bringing the pump up to kill rate speed.
- If recorded pressures are too high, too heavy of a kill fluid will be mixed, causing excessive pressure to be held and resulting in lost circulation.
Shut-In Pressures

- If pressures seem too high, small bleed-offs in pressure may be necessary to determine a correct shut in pressure.
  - If gas is migrating, small bleed-offs may be needed in order to maintain proper bottomhole pressure.
  - *Remember that if original pressures were correct, more influx can enter the well and cause a higher casing pressure.*
  - Because the kick density is usually lighter than the fluid in use, shut-in casing pressure is usually higher than shut-in drillpipe pressure.
  - If the influx is liquid and has a higher density than the fluid in use, the SIDPP will be higher than SICP.
Shut-In Pressures

- On the contrary, if recorded pressures are too low, the kill fluid mixed may not be weighted enough, causing inadequate circulating pressures and resulting in an additional influx.

- Other causes of higher SIDPP over SICP:
  - Trapped pump pressure
  - Quick setting gels
  - Gas entering the string
  - Blockages
Shut-In Pressures

- A technique that is often used, if SIDPP is thought to be incorrect, is to slowly pump several barrels of fluid down the string. This ensures that a good column of fluid exists in the string and that SIDPP will be accurate.
Pressure Between Casing Strings

- Causes of pressure between casing strings include:
  - Poor cement bonds
  - Wear
  - Corrosion
  - Thermal effects on tubulars and packer fluids
  - Liner hanger packer failure

- Always check for pressure between casing strings. Open annulus valve slowly. Use caution when:
  - Nippling down BOP’s
  - Running additional casing strings
If a pump is not operating properly during a well control operation, it must be changed to another pump using the following procedure:

- Hold the casing pressure constant and slow down the pump gradually to a stop.
- Shut-in well.
- Switch to the other pump and bring it up to the desired kill rate.
Pump Failure/Changing Pumps

- Casing pressure should be the same as when shut in the second time and record the circulating pressure.
- This is the new circulating pressure, which may be different from the first pump’s pressure.
  - If a second pump is unavailable, use volumetric techniques while pump is repaired.
BOP Failure

- BOPs should be carefully monitored throughout any well control operations.
- BOP failure can cause additional influx and escape of formation fluids at surface, causing damage of the well and rig.
- Packer elements can be damaged if leakage occurs when the BOP is closed. Increasing closing pressure or using an alternate preventer are methods used to stop leakage.
BOP Failure

- Weephole leakage:
  - Hydraulic leakage indicates main seal of ram shaft has failed.
  - Tightening a hex screw will force packing or sealant material into the seal area to temporarily stop the shaft seal from leaking.

- If a BOP leaks or fails, an alternate lower BOP should be closed.
BOP Failure

- Options if BOP does not close:
  - Closing unit malfunction.
  - Hydraulic line failure.
    - The function should be blocked to avoid losing closing pressure.

- Options for flange/BOP seal failure:
  - Close alternate BOP.
  - Dropping the pipe and closing a blind ram.
  - Pumping a graded sealant into the wellhead.
Problems Downstream from Choke

- Alternate flow and flare routes should be provided in case of plugging or failure of the primary line.

- Alternate chokes should be considered. If main choke washes or plugs, switch to:
  - Secondary remote adjustable chokes.
  - Manual adjustable choke.

- Mud Gas Separator should be monitored for:
  - Plugging
  - Gas blow-by
Pressure Gauge Failure

- It is good practice to read and record pressure from each gauge that may be used during a well control operation.
- If a gauge fails, a secondary gauge should be used.
  - Note: It may not be as accurate as your primary gauge. Therefore, you should record pressures from all gauges that may be used in case of a failure.
- Communication is vital in reading and recording pressures.
  - Gauges should be read as accurate as possible.
Annulus Blockage/Collapse

- An increase in circulating pressure and a decrease in choke pressure can indicate that downhole problems are occurring.
- If pumping continues, pressures below the blockage may increase and cause formation damage/failure.
- Stuck pipe is likely. If blockage prevents circulation, the pipe may have to be perforated or parted to resume well control operations.
Pipe Off Bottom

- It is difficult to maintain BHP if the pipe is off bottom.
  - Kick position vs end of string position.
  - Circulating kick and maintaining proper circulating pressure.
- Install FOSV, IBOP and strip back to bottom.
  - Volumetric techniques must be used.
  - Note: A second FOSV should be available in case the one in the string fails.
Pipe Out of Well

- Kick migration is a major concern.
- Volumetric techniques must be used.
  - If gas reaches surface, lubricate and bleed technique is used.
- Stripping back to bottom may be considered.
  - Stripping calculations must be performed.
  - Safety valves must be used.
  - Top drives have additional ability to pump if necessary.
Floats, check or backpressure valves are used in the string for:
- Pressure work
- Directional drilling
- MWD/LWD tools
- Prevent the annulus from U-tubing

Floats make shut-in drill pipe pressure read zero or read some unreliable intermediate value.
Float, Check or Backpressure Valve (BPV) in String

- The string has to be pressured until the float opens in order to acquire an accurate shut-in drill pipe pressure. This is often called “bumping the float”.
- SIDPP can be determined by using one of the following procedures (depending on the type of pump drive system in use).
- The string has to be pressured until the float opens in order to acquire an accurate shut-in drill pipe pressure. This is often called “bumping the float”.
SIDPP can be determined by using one of the following procedures (depending on the type of pump drive system in use):

**Procedure 1:**
- Pressure the pipe in small increments and stop. This increases pressure in the string with every stroke increment.
- Watch for a pressure decreases after an increment. This means the float opened while pumping and pressure bled back to the SIDPP when stopped.
- Repeat to make sure the reading is accurate.
Float, Check or Backpressure Valve (BPV) in String

Procedure 2:
Slowly pressure up the string using a high pressure/low volume pump.
- The pressure gauge must be carefully monitored for DP changes.
- A slight “bobble” in pressure, or decrease in the rate of rise in pressure may indicate when the BPV is opened.
- This point is the SIDPP. The pressure inside the string is equal with the outside pressure.
**Procedure 3:** Method used if pump can be slowly rolled over or cement type pump available:

- Pump the equivalent of one-half barrel and stop.
- Check casing pressure.
- Repeat procedure until the float opens and there is a noticeable increase in casing pressure. Read value on string as SIDPP.
- These steps should be repeated after bleeding casing pressure back to its original value.
Float, Check or Backpressure Valve (BPV) in String

**Procedure 4:**

If accurate kill rate pressures were recently recorded:

- Bring pump up to kill speed, using correct procedure.
- Adjust casing pressure back to the value it had prior to starting the pump.
- Subtract the kill rate pressure from stabilized standpipe pressure (this is the SIDPP value).

**SIDPP = Circulating Pressure – Kill Rate Pressure**
Stripping/Snubbing Operations

- Stripping is running or removing a string of pipe under pressure.
- Snubbing is when the pipe must be mechanically controlled or the pipe will be ejected due to wellbore pressure.
- Both operations require multiple back pressure valves, both in the string and on surface:
  - Check valves
  - FOSV
  - IBOP
  - Plugs set in string
- A manual choke should be used.
- When stripping in, periodically fill string.
Good practices for Stripping/Snubbing Operations:

- Properly operating annular/stripper pressure regulator valve.
- Minimal closing pressure, adequate to seal.
- Keep pipe lubricated.
- Smooth burrs from pipe, remove pipe protectors/rubbers.
- Use calibrated small volume tank (e.g., “trip tank”) to measure displacement or fill.
- BOP spacing and TJ location critical for ram to ram stripping/snubbing operations.
- Check and bleed off pressure, vent gas from work area critical before opening preventer.
Reciprocating Pipe During Kill Operations

- Some operators require that the pipe should be reciprocated when shut in. Keep in mind that well control operations should be main priority.
- If moving pipe is necessary use good practices as described in stripping/snubbing.
- Use the lowest possible BOP closing pressure, still maintaining a seal, to minimize wear on packer elements.
Lost Circulation

- Lost circulation is a condition where fluid is lost to a formation.
- Three main conditions responsible for lost circulation are:
  - Bad cement jobs
  - Induced fractures
  - Vugular/fractured formations
- Do not maintain “safety margins” if suspected or anticipated.
Lost Circulation
Partial Lost Circulation

- When killing a well with lost returns, often the first sign is fluctuation in pressure or pit level change.
- Minimize any pressure safety margins when circulating the kick out of the hole.
- Maintain fluid volume to continue circulating and removing kick if possible.

*Note:  Once the kick is above lost circulation zone, conditions may improve.*
Partial or lost circulation problems during a well control event may lead to worsening conditions.

- Severe lost circulation: where you cannot add or mix up enough new fluid to keep up with the rate of losses.
- Underground blowouts (UGB): where you cannot control pressures in the well due to severe downhole losses.
Severe Lost Circulation/Underground Blowouts

- Remember, well control operations are a matter of priority and always take care of the worst complication first.
  - If it is the kicking well, try to resolve the kick.
  - If lost returns are too severe, take care of the LC zone problem first and then resolve the kicking zone.
Severe Lost Circulation/Underground Blowouts

- Possible solutions to lost circulation problems:
  - Use of LCM
  - Pumping LCM pill
  - Shut back in and see if formation will heal (note: volumetric techniques may be used.)
  - Spot heavy mud pill to try to kill well
  - Pump barite plug
  - Pump Gunk plug
  - Squeeze gunk pill
Excessive Casing Pressure

- Maximum pressure at the wellhead should not be exceeded.
  - If casing burst or surface control equipment’s pressure limitation is reached, failure may occur resulting in complete loss of control of the well (i.e., blowout).
  - Contingency plans should be adhered to.
  - Bullheading may be considered.
Snubbing into Tubing/String

- Washouts, corroded or plugged strings may require that pipe is run inside the existing string to kill the well.
- Snubbing, coiled tubing and small tubing units have the capability to strip or snub into an existing string.
- Once the smaller string is to kill depth, pumping and kill activities can begin.
Snubbing into Tubing/String
Blockages in the String

- A sudden increase in circulating pressure is a good indicator of a partial or full blockage in the string.
  - The choke should not be opened in an attempt to correct until the problem is identified.
  - Immediately examine the casing pressure. Make sure the pump rate has not changed.
  - If casing pressure is still approximately the same, it is a sign that a partial blockage has occurred. The new pump pressure value should be recorded as the new circulating pressure.
Blockages in the String

- If the pump pressure value is excessively high, cease pumping, shut the well in, and re-establish the correct shut in pressures.
  - A total blockage will cause an abrupt increase in pump pressure and cause casing pressure to start decreasing. Immediately stop the pump and shut the well back in. Begin volumetric techniques.
  - Steps must be taken to correct the problem.
    - Blockage depth determined
    - Clean out if possible
    - If not, perforate, establish circulation and try to regain control of well
Tubulars Too Badly Corroded to Pull from the Well

- It may not be possible to circulate or pull tubulars from the well.
  - The well must be killed prior to removal.
    - Running in the tubing with smaller diameter pipe is an option.
    - Bullheading may also be considered.
      - Down annulus: Could collapse bad tubing
      - Down tubing: May burst tubing
  - The corroded pipe is then washed over and fished from the well.
  - Snubbing operations may be able to fish the pipe from the live well.
Tubulars Too Badly Corroded to Pull from the Well
Tapered Strings/holes

- The vertical height of the kick affects bottomhole and casing pressures.
- If the well has large changes of geometry, shut-in or circulating pressures during a kill technique may quickly change as the kick changes geometry and “shortens”.
- Since well geometry is known, this should not be misinterpreted as potential loss circulation.
Horizontal operations present several well control challenges. These are due to:

- Differences in string make-up
- Effects of gas influx
- Equipment

Kicks are harder to detect because gas doesn’t expand in the horizontal section and register as gains in pits as in a vertical well.
Horizontal WC Considerations

- Kicks are harder to detect because gas does not expand in the horizontal section and register as gains in pits as in a vertical well.
- Gas may also accumulate in “upper” portions of the horizontal well bore.
  - May not give flow show.
  - May be displaced during trips.
- If kick is in the horizontal portion:
  - SIDPP and SICP are nearly the same.
  - Pressures may not increase after stabilization.
    - No gas migration
Horizontal WC Considerations

Gas Pockets
Cuttings
Horizontal WC Considerations

- If kick is in the horizontal portion:
  - SIDPP and SICP are nearly the same.
  - Pressures may not increase after stabilization.
    - No gas migration.

- If vertically fractured areas are drilled:
  - Kick may enter one fracture.
  - Other fractures may be pressured.
  - May lead to UGB and monitoring of pressure critical.
    - Fluctuations up and down in pressure strong indicator.
  - KMW may enter fracture.
  - SIDPP and SICP may not stabilize.
Horizontal WC Considerations

- Killing horizontal wells can involve complex calculations.
  - As such, Driller’s method is usually better choice.
    - KWM annulus HP will not be realized by time “bottom’s up” is circulated.

- Tripping/stripping:
  - Well can be held static if the vertical portion contains KWM.
  - KWM can be circulated out from vertical portion with less dense drilling fluid prior to commencing activities.
    - Well should be monitored for signs it is flowing.
Kill Rate Pressure is Not Available or Reliable

- Known circulating pressures (KRP) critical to WC.
- Kill rate pressure readings are often not properly taken or recorded.
- In non-drilling operations, kill rate pressures are rarely taken.
Kill Rate Pressure is Not Available or Reliable

- KRP may be inaccurate if changes to:
  - Mud properties
  - String components
  - Depth
  - Pump

- Should be recorded/retaken:
  - Every tour
  - MW/Properties change
  - Changes to pump
  - Every 500 ft of new hole
If kick occurs and KRP unreliable/unavailable:

- Open choke slightly prior to starting the pump.
- Keep casing pressure constant at the shut-in value while the pump is being brought up to the desired kill rate.
- Once the pump has been brought up to the desired kill rate, adjust casing pressure to the same pressure as it was when shut-in, and record the circulating pressure.
- This is the initial circulating pressure (ICP).
- To calculate the kill rate pressure (KRP):
  \[ \text{KRP} = \text{ICP} - \text{SIDPP} \]
- When using this procedure, circulate long enough to break the initial gel strength of the fluid.
Pit Changes

- Changes in the fluid level of the pit is an indicator of a kick or lost circulation.
- Any changes should be recorded and reported.
- Estimation of kick size is often very inaccurate, but it is essential that the estimation be as accurate as possible.
  - Vital if complications occur.
- Solids control equipment drainage (when turned off) should be known.
- Large amounts of fluids can be lost from improperly working solids control equipment.
Casing Damage or Failure

- The main causes of casing damage are:
  - Isolate weak zones.
  - Isolate higher pressure zones.
  - Prevent in-flow from zones.
  - Prevent the well from caving in while drilling.

- General casing damage or failure is caused by:
  - Extended pipe rotation.
  - Corrosive formations.
  - Leaks where joints were improperly stabbed or made up.
  - Collapse due to formation exertion.
Cement Plugs

- Cement is one of the better plugs available.
  - May not properly set in moving fluids.
  - Specialized cement mixtures must be used.
    - Should be properly designed and depending on conditions, additives for:
      - Moving liquids
      - Gas
      - Pressure
Plugged Hopper

- Proper weight, KWM and fluid properties are critical during well control operations. If the mud-mixing hopper gets plugged mud properties may not be able to be maintained.
- Dumping weight material directly into a pit does not work as well as using the hopper.
Plugged Hopper
Stuck pipe during WC operations is usually due to differential sticking, but sometimes there are other causes.

Moving pipe through a closed preventer should follow good practices listed under Stripping/snubbing.

Remember that well control is a matter of priorities and sticking the pipe is secondary to controlling the well.
Free Point Detection

- Detecting the depth where the pipe is stuck is necessary for:
  - Depth to part pipe
  - Depth to perforate pipe
- A wire line run free point detector is typically used to determine the depth where the pipe is stuck.
Free Point Detection

- Parting the string and regaining circulation may be accomplished by:
  - **Mechanical internal cutters** – consist of a set of knives that feed out of a mandrel on tapered blocks. As the tool is rotated, the cutters engage and cut the pipe.
  - **Chemical cutters** – produce holes that result in the weakening of pipe, causing the pipe to part at the desired point when pulled.
  - **Jet cutters** – cut the pipe with a shaped charge.
  - **Explosion** – momentary expansion of a connection is caused by string shot charges. Primer cord explosive is fired inside or outside the pipe as torque is applied opposite the thread direction. This causes a partial unscrewing of threads, allowing the pipe to be rotated to break out or release connection.
Fishing is the process used to retrieve equipment or debris that is lost in a well.

Fishing jobs can be performed in open hole, casing, tubing or drill string. Tools are available for fishing using:

- Wireline
- Coiled tubing
- Tubing/drill pipe
Fishing tools are very specific to what must be fished and measurements and dimensions of tools and what’s in the well must be known.

Typical tools and accessories that can be used for fishing:

- Magnets, junk baskets or spears – pick up or catch
- Rotary shoes, mills, cutters & bits – drill, mill and cut
- Rollers, swedges and scrapers
- Spears or tapered tape – to catch internally
- Overshots – to catch externally
Fishing

- An impression block is usually the first tool run. It gives an idea of what may be required to figure out the shape or size of the top of the fish.
- When the shape or size of the top of the fish is known, you can choose the correct catching tool.
- In wells with clear fluids, cameras have been used to identify fish.
- Because of its versatility, an overshot is the most commonly used fishing tool.
- Wash pipe is used to wash down the hole over a fish, only retrieving 3 or 4 joints of fish at a time.
- Magnets are used for retrieving smaller fish.
  - Electromagnets are run on wireline, and permanent magnets are run on tubing or drillpipe.
Fishing

- Among the accessories used to enhance fishing are:
  - Jars
  - Bumper subs
  - Impression blocks
  - Safety joints
  - Accelerators
  - Knuckle joints
  - Washover pipe
Milling

- Mills come in various shapes and sizes and are usually task dependent.
- Uses of mills:
  - To mill away entire sections of tubing, drillpipe, casing or fish that can't be fished out.
  - Cut windows in casing or tubing.
Hot Tapping

- Hot tapping is the process of drilling an entry point into a pipe or a vessel under pressure. It allows for a means of bleeding off or pumping into otherwise sealed vessels.

- Reasons for hot tapping:
  - For drilling a hole in the pipe to relieve pressure caused by trapped pressure between two plugs in the tubing during snubbing.
  - For relieving pressure by drilling into plugged or bridged tubing.
  - For tapping into bull plugs in surface pipe, casing wellheads and manifolds.
  - For tapping into string to bleed off trapped pressure after setting a frozen plug in the string.
Hot Tapping

• For relieving pressure by drilling into plugged or bridged tubing.
• For tapping into bull plugs in surface pipe, casing wellheads and manifolds.
• For tapping into string to bleed off trapped pressure after setting a frozen plug in the string.
Hot Tapping
Freezing is used to seal tubing, drill pipe, casing or surface equipment. It is used when surface equipment fails or must be removed.

- Equipment can be removed or replaced if properly frozen.
- There must be a static fluid condition at the desired freeze point in order to perform a freeze operation.
  - The pill has to be held static in order to be successful.
Freezing – Concerns & Cautions

• A special gel-like fluid must be spotted at the desired freeze point by pumping through the kelly or using a hot tap and frozen in place using a dry ice bucket.
  - This gel provides the proper viscosity and solids that are necessary to hold the solution in place.
  - More viscosity is necessary to keep the pill in place for spotting in gas or empty pipe.

• Since freezing causes water to expand, it can damage the vessel it is freezing in.
  - Solids compress and produce a cushion for water expansion.
Freezing – Concerns & Cautions
Mechanical & Hole Problems

- Communication is especially critical during well control operations.
- Remember to “think downhole”:
  - Anticipate potential problems and have plan of action to solve it.
- Equipment should be continually checked for proper operation and possible signs of failure.
- Monitoring of gauges for changes in pump pressure and casing pressure is extremely important for detecting mechanical and hole problems.
- Document everything!
## Complications – During Kick Circulation

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<th>PROBLEM</th>
<th>TUBING PSI</th>
<th>CASING PSI</th>
<th>BOTTOMHOLE PSI</th>
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### Misconceptions and Why They Do Not Work

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<td>Circulate With Constant Casing Pressure</td>
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<td>Decrease Pump Rate While Holding Casing Pressure Constant</td>
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Complications

Objectives Learned

- You learned to detect changes that deviate from established trends.
- You learned how to respond to problems such as:
  - Pump problems
  - String problems
- Hole complications
- Choke problems.
- You became familiar with information regarding stripping and general snubbing