CAUSES OF KICKS
Causes of Kicks

Learning Objectives

- You will learn the causes of kicks including:
  - Characteristics and behavior of kicks.
- What happens if you don’t respond to a kick.
- Surface and underground blowouts.
Overview

Causes and Warning Signs of Kicks

- A kick is an unscheduled, unwanted entry of water, gas or oil into the wellbore.
- A kick may occur whenever a permeable formation is exposed – no matter what type of operation.
- Therefore all personnel must be aware of kick indicators and be prepared to take immediate action if any indicator or warning sign of a kick appears.
Overview

Causes and Warning Signs of Kicks

- The worst kind of kicks are gas kicks.
  - If ignored or not detected, gas will migrate and/or be pumped up the well, expanding uncontrolled, displacing fluid from the well further reducing HP and allowing more kick fluid to enter.
  - Never assume a kick to be a liquid kick (i.e., oil or saltwater).
  - Treat every kick as if it were a gas kick.
CO₂ Kick

WILD WELL CONTROL
Overview

- Gas behavior in wellbore:
  - In most fluids gas migrate towards surface. This is because it is less dense than fluids in use.
  - Gas kicks in oil based show little migration as it may dissolve and remain in the fluid until near the surface where it no longer has the pressure required to keep it in solution. It quickly expands giving personnel little or no time to react.
Overview

- Gas behavior in wellbore:
  - In most Gas kicks in certain fluids types, such as oil based fluids may mask or disguise some of the more common signs of a kick as gas is immiscible in these fluids.
  - Gas behavior and immiscibility depends on the type of fluid in use, pressure, temperature, pH, and the amount of time that the gas is exposed to the liquid.
  - The volume that gas is allowed to occupy is related to the pressure in the gas. (Boyle’s Law).
  - If a gas is NOT allowed to expand, pressure stays constant except for changes in temperature.
Overview

- Gas behavior in wellbore:
  - In most, if gas comes from the bottom of the hole to the top without being allowed to expand, it will carry the same amount of pressure to the top that it had at the bottom.
  - The pressure exerted by this gas will pressurize the well and eventually cause equipment failure, formation breakdown, or lost circulation.
Overview

- Gas can be compressed into liquid with enough pressure.
  - While gas is compressible, liquids such as oil and water are hardly compressible.
  - Since they share this common characteristic, their pumping and return rates are fairly equivalent.
  - Liquid kicks do not migrate as much as gas kicks do.
  - Once a gas is in a liquid state it will not compress significantly.
  - A liquid gas kick will expand rapidly once it reaches its bubble point.

**REMEMBER:** *It is important to treat every kick as if it were a gas kick.*
Consequences of Not Responding to a Kick

- There are serious consequences of allowing a well to get out of hand.
- These include loss of:
  - Human life
  - Natural resources
  - Environment due to pollution
  - Rig equipment
Consequences of Not Responding to a Kick
Defining Types of Blowouts

- A kick that is not recognized and controlled will eventually “blow out” fluid from the well, resulting in a blowout.
- Shutting in a well will not stop gas from migrating and increasing wellbore pressure. This can lead to downhole formation or casing failure.
- An underground blowout occurs when a well blows out fluid from one zone into another formation.
- Blowouts frequency is about equal between tripping and all other activities.
Causes of Kicks

A kick occurs when the formation pore pressure is greater than the pressure exerted by the column of fluid in the well. The most common causes of kicks are:

- Lost circulation
- Abnormal pressure
- Obstructions in the wellbore
- Cementing operations
- Insufficient fluid density
- Poor tripping practices
- Improper hole fill while tripping
- Swabbing/surging
Causes of Kicks

• Excessive drilling rate through gas sand
• Excessive water loss of drilling fluid
• Drilling into an adjacent well
• Charged formations
• Obstructions in wellbore
• Testing BOPs
• Trapped gas below BOPs
• Loss of subsea riser
• Secondary recovery projects
• Water flushes
• Drill stem testing
• Underbalanced drilling – failure to maintain sufficient backpressure
• Jack-up leg Failure
Insufficient Fluid Density

- The fluid in the wellbore must exert hydrostatic pressure equal to the formation pore pressure.
- If the hydrostatic pressure is less than the formation pressure the well can flow and cause a kick.
  - The most common cause of inadequate fluid density is drilling into an unpredicted abnormally pressured formation.
  - Insufficient fluid density can also be the result of misinterpreting drilling parameters and not acting properly.
Insufficient Fluid Density

• High temperatures can make the mud less dense.
• Rainwater can affect fluid density and alter fluid properties
• Other reasons for improper fluid density include:
  ▪ changing out present fluid in the well for fracturing acid jobs.
  ▪ spotting large pills.
Insufficient Fluid Density
Failure to Keep Hole Full of Fluid

- One of the most common causes of kicks.
- As pipe is removed from the well, the fluid level in the well drops.
- If the fluid level in the hole falls, then the Hydrostatic Pressure (HP) exerted by the fluid will also fall, and when the hydrostatic falls under the formation pressure, the well may flow.
- We can calculate the drop in fluid level as pipe is pulled.
Failure to Keep Hole Full of Fluid

- Calculations for this are based on fluid density and the displacement of the pipe and tripping practices.
- Depending on conditions, pipe may be pulled dry or wet.
  - If pipe is pulled *dry*, it is because of a heavy slug that was pumped in the string prior to the trip, pushing out a length of the less heavier fluid in the pipe.
  - To calculate the drop in HP per foot of pipe pulled *dry*:

\[
\Delta P_{\text{psi/ft}} = \frac{0.052 \times \text{MW}_{\text{ppg}} \times \text{DPDisplacement}}{\text{AnnulusCapacity}_{\text{bbl/ft}}} + \frac{\text{DPCapacity}_{\text{bbl/ft}}}{\text{AnnulusCapacity}_{\text{bbl/ft}}} 
\]
Failure to Keep Hole Full of Fluid

- If pipe is pulled wet, it is probably due to not pumping a slug or not allowing a slug time to drop. However, if a slug was pumped and the pipe begins to pull wet, a kick may be in the well.

- To calculate the drop in HP per foot of pipe pulled wet:

\[
\Delta P_{\text{psi/ft}} = 0.052 \times MW_{\text{ppg}} \times \left( \frac{\text{DP Capacity bbl/ft} + \text{DP Displacement bbl/ft}}{\text{Annulus Capacity bbl/ft}} \right)
\]

Note: It is accepted and required by some regulatory bodies while tripping that the \( \Delta P \) be 75 psi, not exceeding pulling 5 stands at a time.
Tripping Out

- **Pulling pipe out of the well is a leading cause of kicks.**

- Kicks occurs during a trip out when there is insufficient fluid weight to hold the formations back, due to the reduction of hydrostatic pressure by not pumping this pressure is called ECD (equivalent circulating density).
Tripping Out

- Once the pumps are shut down, circulating pressure is lost and bottomhole pressure is reduced to the hydrostatic pressure of the fluid in the annulus.
- This reduction in bottomhole pressure may cause a kick.
- Before tripping, carefully monitor the hole to see if the well is still flowing after the pumps are shut down. No flow indicates that the trip out may begin.
Safety Margins are used to compensate for the loss pump pressure friction in the annulus.

- **Trip margins** are estimated increases in fluid density prior to a trip to compensate for loss of circulation pressure.
- There is one major difference between a trip margin and a slug.
  - A slug only increases the bottomhole pressure when it falls out of the pipe, never before the trip.
Safety Margins

- Too much of a trip margin can cause lost circulation.
- An insufficient margin may allow the well to kick.
- The size of the trip margin requires good judgment and is dependent on the:
  - Size of the hole.
  - Hole's condition.
  - Pipe pulling speed.
  - Fluid and formation properties.
Swabbing and Surging

- Swab and surge forces are present whenever pipe is moved through a fluid.
- **Swabbing** – a lowering of hydrostatic pressure in the wellbore due to the upward movement of pipe and downhole tools.
  - When fluid in the well does not drop as quickly as the string is being pulled, it creates a suction force and reduces the pressure below the string.
Swabbing and Surging

- **Surging** – a rapid increase in pressure downhole that occurs when the string is lowered too quickly or when the mud pump is brought up to speed after starting.
  - When the string is lowered too fast, fluid does not have a chance to move out of the way, resulting in a process called surging.
  - This may cause pressure to increase throughout the well and cause a leak-off or fracture.

**REMEMBER:** *Slowing down tripping speed will minimize surge and swab pressures.*
Factors Affecting Swab and Surge

Trip Speed

- Swab or surge pressures are directly affected by the rate of pipe movement.
  - The quicker the pipe moves, the more the swab and surge pressures and the greater the potential for swabbing in an influx.
  - Speed combined with BHA length, stabilizers, floats, packers, fluid properties and smaller diameters increase swab/surge pressures.
  - One obvious sign of surging is mud flowing over the top of a tool joint while running into the well.
Factors Affecting Swab and Surge

Clearances

- The clearance between the pipe and the wellbore is one of the most significant factors in swab pressure. The smaller the clearance, the more restraint fluid must overcome to flow properly.

- **Balling** – refers to materials that collect around the string and reducing the clearance between the string and hole.
Factors Affecting Swab and Surge

- **Pulling into Shoe** – The reduction of clearance as the bottomhole assembly is pulled up into the casing.
- **Salt and Swelling Formations** – Salts close in around the string, permitting barely enough clearance for circulation. Clays swell to wellbore clearance and increase the chance for the well to be swabbed in.
- **Hole angle and Doglegs** – BHA scraping against wellbore and can pick up debris and diminish clearance when pulling up through deviated wells and dogleg areas.
- **Number of Stabilizers** – The more stabilizers, the greater the chance of balling and swabbing.
Factors Affecting Swab and Surge

- Fluid Properties
  - Swabbing and surging are dependent on the rising/lowering and flowing of fluid from where it was before pipe was moved, so the properties of the fluid are important. The following properties are important:
    - **Viscosity** – the readiness for fluid to flow and is probably the most crucial of all factors in swabbing. If fluid viscosity is high, it is more difficult for a fluid to flow downward, so the pipe must be pulled slower.
Factors Affecting Swab and Surge

- **Gel Strength** – the attraction of solids in a fluid to each other. Fluids with high gel strengths increase the likelihood of swabbing while tripping. Typically, the longer the duration without circulating, the thicker the fluid may become partly due to this property.

- **Filter Cake (Filter Loss)** – When filtrate is excessive creating an immense build up of cuttings and other mud additives on the formation wall. The filter cake is reducing the diameter of the well bore once again causing swab/surge effects.
Improper Displacement

- To maintain the HP on the well during a trip out, the well must be filled. This fill should equal the displacement of pipe removed.
  - Trip and re-circulating tanks are the most accurate means for measuring the amount of fluid that a hole is taking. This should be recorded on a trip sheet.
  - Short trips or clean out trips are used to determine wellbore conditions and include a safety factor.
  - Pump strokes also measure fluid that a hole is taking, but they do not measure as precisely as trip tanks.
Lost Circulation

- If loss of circulation occurs, the fluid level falls.
- As fluid level falls, hydrostatic pressure decreases.
- If hydrostatic pressure of fluid falls below formation pressure the well may flow.
Circulating Pressure

- Circulating adds pressure to the bottom of the hole and annulus this combined pressure is your ECD.

- If friction and hydrostatic pressure exceed formation pressure to the extent of formation breakdown loss of hydrostatic pressure will result as a loss of fluid.
Wellbore Obstructions

- If there is a wellbore obstruction, pressure may become trapped below it.
- Unexpected high pressures may be trapped below packers or downhole obstructions.
- The release of the pressure can constitute a kick.
- If pressure forces fluid from well, hydrostatic is reduced and a kick may occur.
Even the best equipment eventually fails.

Many blowouts have occurred as a result of equipment failure.

- Improper maintenance
- Excessive wear
- Excessive pressure
- Corrosion
Cementing Operations

- Chemical changes occur during the hardening of cement. This may lead to several well control problems such as:
  - Gas channeling through the cement.
  - Reduction in HP resulting in a kick.
  - Poor cement bond between casing and formation.

- Pit volume increase and cement displaced should be monitored to ensure the displaced fluid volume is equal to the amount of cement volume pumped.
Unusual Situations Causing Kicks

- Drilling into an Adjacent Well – many times, a kick has penetrated from one well to another.
- Testing BOPs – too many times there is too much attention focused on the actual testing of the well instead of making observations for safety.
- Drill Stem Tests (DST) – a drillstem test may be considered a temporary completion of a production zone.
- Platform Leg – jacking up a rig or other support mechanisms have caused blowouts.
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