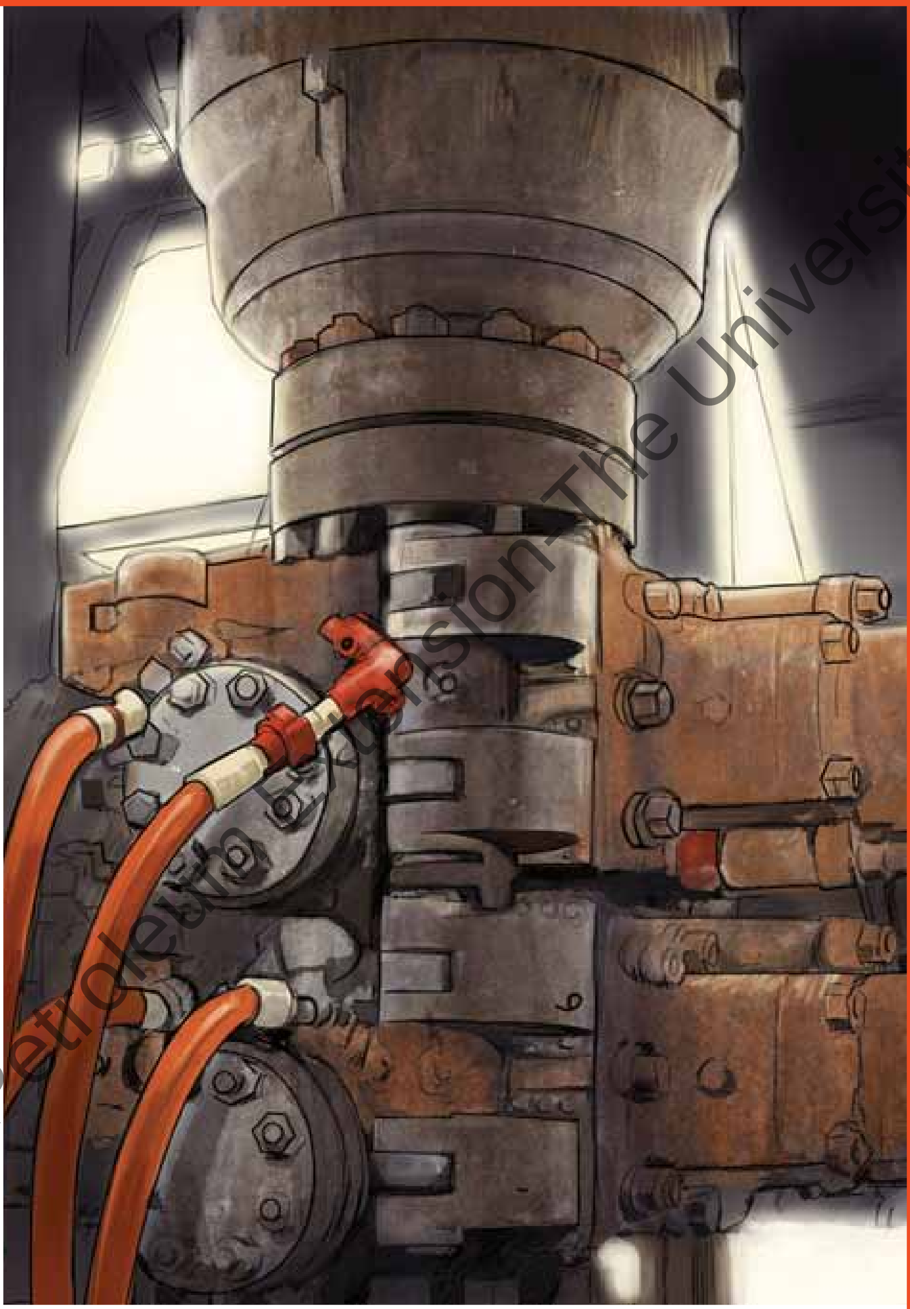
ROTARY DRILLING

Blowout Prevention



Fourth Edition

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About the Authors

TIM BELL

Tim Bell is a Senior Well Control Engineer for Cudd Well Control. Tim has over eight years experience in the oil and gas industry. He is involved in all phases of well-control engineering, including blowout contingency planning, dynamic well-kill design and execution, underground blowout control, rig equipment inspections, engineering, and field operations.

Tim has experience in the majority of petroleum producing states in the United States. He also has experience with international blowouts, firefighting operations, on- and offshore events, inland barge blowouts, H_2S wells, oil-based mud kicks, and high-pressure and geothermal wells. Tim has been involved with special service projects including ROV assisted subsea hot tapping, freeze jobs and post-event consulting. Tim has held several positions in well control, drilling, completions, production and workovers as an operations engineer and wellsite supervisor. In addition to blowouts and well-control jobs, Tim's past projects have included horizontal wells, coalbed methane exploration and development, deep gas wells, and unconventional tight gas reservoirs.

Tim graduated from Texas Tech University with a Bachelor's degree in Petroleum Engineering. Upon graduation, he was hired by Devon Energy as an operations engineer. In the fall of 2004, Tim left Devon to become Vice President of Operations for Quest Resources. Tim made the move to Cudd Well Control in January of 2007 and currently holds the position of Senior Well Control Engineer. Tim is involved in all aspects of well-control engineering, blowout intervention and firefighting operations and recovery. Tim is a member of the Society of Petroleum Engineers and is IADC WellCAP certified.

DANIEL EBY

Dan Eby is the Vice President of Operations and Engineering Manager for Cudd Well Control. Dan has 29 years of experience in the petroleum industry with several major oil companies and well-control service providers. As Vice President of Operations, Dan is in charge of the daily operation of Cudd Well Control, including all technical field work and business decision making.

As Engineering Manager, he is involved in all phases of well-control engineering including blowout contingency planning, relief well planning, dynamic kill design and execution, and field operations.

Dan has worked in over 30 different countries with diverse assignments in well control, drilling, completions, and workover. He has acted as both project engineer and well site supervisor. In addition to blowouts, the projects include deepwater exploration, HPHT sour gas wells, horizontal wells, subsea completions, coalbed methane exploration, and hazardous waste disposal wells.

In addition to work on well-control jobs and blowouts, Dan's experience includes well-control instruction, development of well-control technical manuals, development of recommended practices for unconventional well-control problems, acting as MMS liaison, and the design and supervision of high-pressure snubbing jobs, both onshore and offshore.

Dan graduated from Texas A&M University with a B.S. in Building Construction in 1977, followed by a B.S. in Civil Engineering in 1979. Dan is a licensed professional engineer in the state of Texas and a member of the Society of Petroleum Engineers, National Society of Professional Engineers, Texas Society of Professional Engineers, and the International Association of Drilling Contractors Well Control Committee.

JACE LARRISON

Jace Larrison is a Senior Well Control Engineer for Cudd Well Control. Upon graduation, Jace began work for Cudd Pressure Control, now Cudd Energy Services (CES), as a field engineer for snubbing and coiled tubing. Jace has an extensive background in snubbing operations that includes operational soundness with 170K hydraulic rig-assist units as well as all sizes of CES Stand-Alone (HWO) units. Special Service experience includes hot tapping, cryogenic freezing, conventional dry-ice freezing, and valve drilling operations. Jace has well-control operational experience on projects including onshore, inland water, and offshore critical pressure control situations, onshore blowouts, geothermal blowouts, inland water blowouts, high volume H_2S blowouts and numerous other special projects related to well control. Jace has worked in most oil and gas producing areas of the United States as well as many international locations such as Australia, Saudi Arabia, Qatar, Turkmenistan, Kazakhstan, Libya, and Egypt.

Jace is involved in all aspects of well-control engineering, including Blowout Contingency Planning (BCP), well-control equipment inspections, recommendations for special well-control problems, kill design and execution, kick resolution and modeling, and all aspects of field operations. Jace has also taught several industry classes related to well-control subject matter and has been involved in giving numerous presentations at industry-related events such as case histories and well-control topic discussions.

Jace is a graduate of Texas Tech University with a B.S. in Petroleum Engineering. In 2002, he received the Texas Tech SPE outstanding member of the year award and was a TTU SPE officer for the 2002–2003 academic year. Jace is a member of the American Association of Drilling Engineers and the Society of Petroleum Engineers.

BHAVESH RANKA

Bhavesh Ranka is a Well Control Engineer with Cudd Well Control. He graduated from Mumbai University in India with a degree in Chemical Engineering. He received his M.S. in Natural Gas Engineering from Texas A&M University, Kingsville.

He has been involved in all aspects of well-control engineering including blowout contingency plans, well-control equipment inspection, drilling plan reviews, gas dispersion modeling, and kick simulation. His work in field operations includes blowouts, rig fires, and well-control operations.

Bhavesh has worked offshore and at onshore locations in Texas, Louisiana, Oklahoma, Colorado, New Mexico, Montana, and Wyoming. He has also been involved in well-control training. His special services experiences include hot-tap, valve drilling, and freeze operations.

Units of Measurement

Throughout the world, two systems of measurement dominate: the English system and the metric system. Today, the United States is one of only a few countries that employ the English system.

The English system uses the pound as the unit of weight, the foot as the unit of length, and the gallon as the unit of capacity. In the English system, for example, 1 foot equals 12 inches, 1 yard equals 36 inches, and 1 mile equals 5,280 feet or 1,760 yards.

The metric system uses the gram as the unit of weight, the metre as the unit of length, and the litre as the unit of capacity. In the metric system, 1 metre equals 10 decimetres, 100 centimetres, or 1,000 millimetres. A kilometre equals 1,000 metres. The metric system, unlike the English system, uses a base of 10; thus, it is easy to convert from one unit to another. To convert from one unit to another in the English system, you must memorize or look up the values.

In the late 1970s, the Eleventh General Conference on Weights and Measures described and adopted the Systeme International (SI) d'Unites. Conference participants based the SI system on the metric system and designed it as an international standard of measurement.

The Rotary Drilling Series gives both English and SI units. And because the SI system employs the British spelling of many of the terms, the book follows those spelling rules as well. The unit of length, for example, is metre, not meter. (Note, however, that the unit of weight is gram, not gramme.)

To aid U.S. readers in making and understanding the conversion system, we include the table on the next page.

English-Units-to-SI-Units Conversion Factors

Quantity or Property	English Units	Multiply English Units By	To Obtain These SI Units
Length, depth, or height	inches (in.)	25.4	millimetres (mm)
		2.54	centimetres (cm)
	feet (ft)	0.3048	metres (m)
	yards (yd)	0.9144	metres (m)
	miles (mi)	1609.344	metres (m)
		1.61	kilometres (km)
Hole and pipe diameters, bit size	inches (in.)	25.4	millimetres (mm)
Drilling rate	feet per hour (ft/h)	0.3048	metres per hour (m/h)
Weight on bit	pounds (lb)	0.445	decanewtons (dN)
Nozzle size	32nds of an inch	0.8	millimetres (mm)
Volume	barrels (bbl)	0.159	cubic metres (m^3)
		159	litres (L)
	gallons per stroke (gal/stroke)	0.00379	cubic metres per stroke (m^3/stroke)
	ounces (oz)	29.57	millilitres (mL)
	cubic inches ($in.^3$)	16.387	cubic centimetres (cm^3)
	cubic feet (ft^3)	28.3169	litres (L)
		0.0283	cubic metres (m^3)
	quarts (qt)	0.9464	litres (L)
	gallons (gal)	3.7854	litres (L)
	gallons (gal)	0.00379	cubic metres (m^3)
	pounds per barrel (lb/bbl)	2.895	kilograms per cubic metre (kg/m^3)
	barrels per ton (bbl/tn)	0.175	cubic metres per tonne (m^3/t)
Pump output and flow rate	gallons per minute (gpm)	0.00379	cubic metres per minute (m^3/min)
	gallons per hour (gph)	0.00379	cubic metres per hour (m^3/h)
	barrels per stroke (bbl/stroke)	0.159	cubic metres per stroke (m^3/stroke)
	barrels per minute (bbl/min)	0.159	cubic metres per minute (m^3/min)
Pressure	pounds per square inch (psi)	6.895	kilopascals (kPa)
		0.006895	megapascals (MPa)
Temperature	degrees Fahrenheit (°F)	$\frac{°F - 32}{1.8}$	degrees Celsius (°C)
Thermal gradient	1°F per 60 feet	—	1°C per 33 metres
Mass (weight)	ounces (oz)	28.35	grams (g)
	pounds (lb)	453.59	grams (g)
		0.4536	kilograms (kg)
	tons (tn)	0.9072	tonnes (t)
	pounds per foot (lb/ft)	1.488	kilograms per metre (kg/m)
Mud weight	pounds per gallon (ppg)	119.82	kilograms per cubic metre (kg/m^3)
	pounds per cubic foot (lb/ft^3)	16.0	kilograms per cubic metre (kg/m^3)
Pressure gradient	pounds per square inch per foot (psi/ft)	22.621	kilopascals per metre (kPa/m)
Funnel viscosity	seconds per quart (s/qt)	1.057	seconds per litre (s/L)
Yield point	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Gel strength	pounds per 100 square feet (lb/100 ft^2)	0.48	pascals (Pa)
Filter cake thickness	32nds of an inch	0.8	millimetres (mm)
Power	horsepower (hp)	0.75	kilowatts (kW)
Area	square inches ($in.^2$)	6.45	square centimetres (cm^2)
	square feet (ft^2)	0.0929	square metres (m^2)
	square yards (yd^2)	0.8361	square metres (m^2)
	square miles (mi^2)	2.59	square kilometres (km^2)
	acre (ac)	0.40	hectare (ha)
Drilling line wear	ton-miles (tn•mi)	14.317	megajoules (MJ)
		1.459	tonne-kilometres (t•km)
Torque	foot-pounds (ft•lb)	1.3558	newton metres (N•m)

Overview

In this chapter:

- The history of the Lucas well at Spindletop
- The probable causes of the blowout at the Lucas well
- The signs of an imminent well kick that can lead to a blowout

On January 10, 1901, the *blowout* of the Lucas well at Spindletop near Beaumont, Texas, was spectacular and widely publicized. Before the development of *blowout preventers (BOP)*, blowouts were common. They were called *gushers* if they produced oil.

The Hamill brothers had started drilling the Lucas well three months earlier using a new tool called a *rotary drill*. Because of their experience using the rotary drill, the Hamills had been hired by Anthony F. Lucas and his partners to come to Beaumont to try drilling through the sand and rock at Spindletop (fig. 1).

Figure 1. Anthony Lucas, chief engineer at Spindletop

A 6-inch (15.24 centimetres) diameter *casing* was set at 880 feet (268 metres), where it was expected that oil would be found. When no oil was struck, the well was deepened to 1,020 feet (310.9 metres). The final 140 feet (42.67 metres) of drilling proceeded quickly—much faster than had been drilled before. The crew was preparing a new *bit* with 700 feet (213.4 metres) of *drill pipe* in the hole when the well started to unload; that is, drilling mud started flowing from the casing.

Formation Pressure

In this chapter:

- Rock formations that can trap oil
- The difference between and causes of formation pressure and hydrostatic pressure
- The causes of formation pressure gradients
- How to calculate hydrostatic pressure
- The differences among normal, abnormal, and subnormal hydrostatic pressures
- The interdependence of formation and hydrostatic pressure in well control
- The measurement and control of circulating pressures caused by drilling fluid and equipment

To classify layers of rock, geologists use a basic subdivision called a *formation*. A formation is a rock unit that is distinctive and consists of a certain number of rock strata with comparable or similar properties. Therefore, the characteristics of formations result in differences in the way fluids are trapped (fig. 4).

Formation pressure is the force exerted by fluids in an underground rock formation. In drilling operations, formation pressure is measured and recorded using a drilled hole at the depth of the formation with the well's surface valves completely closed or *shut-in*. It is sometimes referred to as reservoir pressure. Formation pressure must be carefully monitored and controlled during drilling operations. This is an important factor in blowout prevention.

Abnormal-Pressure Formations

In this chapter:

- Shale compaction as a cause of abnormal formation pressure
- Common signs and detection methods used to locate abnormal formation pressures

Abnormal formation pressure and lost circulation in *unconsolidated formations* are related problems. Higher than normal formation pressure gradients are encountered at varying depths in many locations. These areas require extra care to be productive and incur additional drilling expense. Costly blowouts can occur when abnormal pressure zones are unexpectedly penetrated.

Shale Compaction

A rock with *pores* or open spaces is called *porous.* Hydrocarbons can occur only in porous reservoir rocks. A porous rock has a measurable quality called *porosity*. Porosity can be very low, almost zero or, in theory, it can be as high as 55% for extremely well-sorted (same diameter) rock grains. Because most rocks have grains of varying sizes, the practical limit of porosity is usually around 30% for sandstone.

Kick Detection

In this chapter:

- Preliminary events that indicate a kick has been taken
- Well-control equipment used to assess and detect a kick
- Some corrective measures used to stop a kick

Drilling abnormally-pressured formations is known to be hazardous, but many well-control problems also happen in normal formation pressures. Some problems occur while pipe is being moved in or out of the borehole (fig. 22).

When the first stands of pipe are pulled or tripped out, there can be a reduction in bottomhole pressure. This may be caused by the cessation of circulation, and perhaps because of swabbing. If there is any indication of flow, the well should be shut-in and circulated by following standard well-control practices to remove any influx and fill the well with clean drilling fluid. If necessary, the mud weight should be increased before subsequent attempts to trip the pipe.

Sometimes, the preliminary indications of a kick are almost unmistakable. These "positive" indicators include:

- Unexplained mud-pit gain
- Mud flow with the pumps off
- Increase in flow while circulating

In other cases, the indications of a possible kick are ambiguous. These "possible" indicators include:

- A drilling break, a sudden increase in *ROP* (rate of penetration)
- Decrease in circulating pressure
- Shows of gas, oil, or salt water

Strong indicators of a kick include:
- Unexplained mud-pit gain
- Mud flow with the pumps off
- Increase in flow while circulating

Killing a Well Kick Onshore

In this chapter:

- Steps to control an onshore well kick
- Steps to control a well kick while making a trip
- Various methods, procedures and calculations used to kill a kick
- Killing a well kick with the pipe off the bottom of the borehole
- Common mistakes made in killing a well kick

By taking immediate action, the driller can minimize the size of a kick. Minimizing the size of the kick and can greatly enhance the ability of a drilling crew to handle the kick properly. Quick action can prevent the situation from escalating into a blowout.

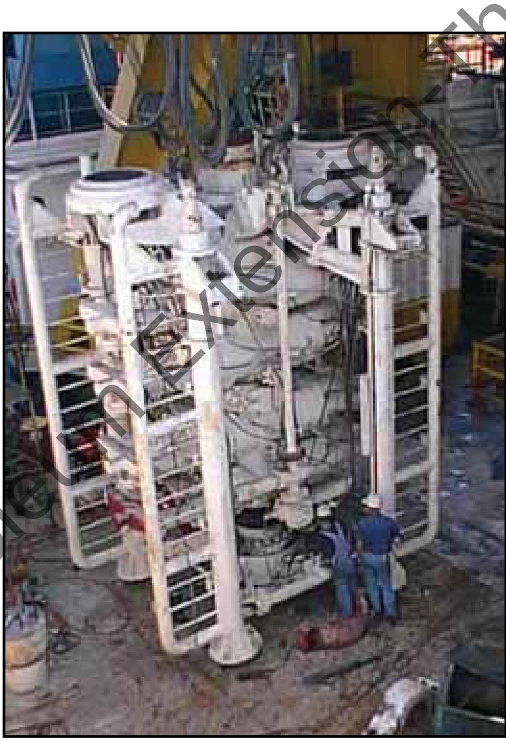
When a kick is detected, following the proper sequence of steps is critical to successful emergency control. Depending on the cause, differing methods and procedures may be used to kill a well kick.

Kick Control in Offshore Operations

In this chapter:

- Procedures in controlling a kick offshore from a floating rig
- Diverter BOP systems
- Procedures for well control with a diverter system

The procedures for controlling kicks in offshore drilling from a floating rig are similar to those for onshore as discussed in the previous chapter. Offshore may refer to any body of water, including inland lakes, seas, and rivers. There are additional steps and additional equipment with which crewmembers must be familiar (fig. 36).



Courtesy of Cudd Well Control

Figure 36. A subsea ram-type blowout preventer

Special Problems in Kick Control

In this chapter:

- The dangers of shallow gas formations
- Procedures and calculations required to control kicks with the drill pipe out of the hole
- Well-control problems encountered when stripping into the hole
- Well-control problems encountered when stripping out of the hole
- The procedures and equipment used in snubbing operations
- The procedures used to control lost circulation

Shallow Gas Formations

Shallow gas formations present a danger because:

- The gas pocket is generally at a depth that allows a potential kick to rapidly unload the mud from the wellbore, and
- Shutting in the well might cause the formation to fracture and the wellbore fluids to broach all the way to the mud line.

Either of these possibilities can result in a serious well-control problem. If a shallow gas kick occurs before enough casing is set, the diverter system will divert the flow away from the rig. For a kick in a shallow gas formation, the offshore crew should take the same steps as those listed for diverting the well in the previous chapter.

Preventer Equipment

In this chapter:

- The main pieces of equipment used in well control and blowout prevention
- The purpose and function of each piece of equipment
- Auxiliary and accessory rig equipment that contributes to well control

The hydrostatic pressure of the drilling fluid column on the formation is the primary barrier in preventing a well from blowing out. When formation pressure is greater than the hydrostatic pressure of the mud column, BOPs and related equipment shut in a well at the surface and serve as a second barrier.

In addition to BOPs, other equipment is used to assist in the control of well pressure. Chokes and choke manifolds allow a controlled removal of the intruded formation fluids from the wellbore. Mud-gas separators help conserve drilling fluids while removing the gas from the drilling fluids and discharging the gas to the atmosphere. *Rotating heads* permit drilling to continue at an increased ROP in formations with high-pressure/low-volume gas flow.

Preventer Tests and Drills

In this chapter:

- The reasons for BOP pressure testing
- The methods for testing various BOP components

Blowout preventers are emergency equipment. The BOPs are only effective if they:

- Can handle the pressure involved
- Are in good operating condition, and
- Are used correctly

The decision to provide adequate BOPs involves the operating company, the drilling contractor and the drilling crews. The drillers on the rig are key in the responsibility, but every crewmember should know how to operate the preventer equipment and be alert to the signs of a well kick. Function testing of the preventers and careful pressure testing ensures that everything is in good operating condition and ready for use.

Testing of the BOPs to their rated pressure (if equal to or below the rating of the wellhead) should be conducted to confirm that the equipment will hold under the given test pressure. All preventers and valves, including the choke manifold, should be tested with pressure from the upstream side. Therefore, test pressure is applied to the preventer or valve from the side normally originating the pressure in a kill situation.

Frequent operational checks and regular pressure tests ensure that valves and other components are in good working order. Lubrication, as necessary, ensures easy operation of the equipment in an emergency. Regular maintenance is less expensive than replacement of an item or the possibly drastic consequences incurred when equipment does not function properly.

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