ROTARY DRILLING

The Bit

Fifth Edition

UNIT I • LESSON 2

PETEX

ROTARY DRILLING SERIES

Unit I: The Rig and Its Maintenance

Lesson 1: The Rotary Rig and Its Components
Lesson 2: The Bit
Lesson 3: Drill String and Drill Collars
Lesson 4: Rotary, Kelly, Swivel, Tongs, and Top Drive
Lesson 5: The Blocks and Drilling Line
Lesson 6: The Drawworks and the Compound
Lesson 7: Drilling Fluids, Mud Pumps, and Conditioning Equipment
Lesson 8: Diesel Engines and Electric Power
Lesson 9: The Auxiliaries
Lesson 10: Safety on the Rig

Unit II: Normal Drilling Operations

Lesson 1: Making Hole
Lesson 2: Drilling Fluids
Lesson 3: Drilling a Straight Hole
Lesson 4: Casing and Cementing
Lesson 5: Testing and Completing

Unit III: Nonroutine Operations

Lesson 1: Controlled Directional Drilling
Lesson 2: Open-Hole Fishing
Lesson 3: Blowout Prevention

Unit IV: Man Management and Rig Management

Unit V: Offshore Technology

Lesson 1: Wind, Waves, and Weather
Lesson 2: Spread Mooring Systems
Lesson 3: Buoyancy, Stability, and Trim
Lesson 4: Jacking Systems and Rig Moving Procedures
Lesson 5: Diving and Equipment
Lesson 6: Vessel Inspection and Maintenance
Lesson 7: Helicopter Safety
Lesson 8: Orientation for Offshore Crane Operations
Lesson 9: Life Offshore
Lesson 10: Marine Riser Systems and Subsea Blowout Preventers

Contents

About the Author

From Europe to Africa to the Commonwealth of Independent States, Mark Jordan has supervised a number of engineering groups in the field, confronting a wide variety of bit applications and design specifications. He has over 35 years of experience in the oil industry, performing roles ranging from mud logging, core analysis, engineering, sales, and senior management. Over the past two decades, Mark has assumed key positions at Schlumberger, ReedHycalog, and National Oilwell Varco (NOV), devoting much of his career to the bit and other downhole tool product lines. In his current role at NOV, Mark is committed to transferring his background and experiences to the next generation of industry professionals, providing new employees with the support and knowledge they need for understanding bit applications, selection, bottomhole assembly, and techniques for maximizing drilling performance.

Mark holds a B.S. Honours degree in Geology from the University of Dundee in the United Kingdom and is a member of the Society of Petroleum Engineers (SPE) and the Fellowship Geological Society (FGS).

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)	$\frac{^\circ F - 32}{1.8}$	degrees Celsius (°C)
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)

Introduction

In this chapter:

- An overview on how bits are used
- Cutting structures and diamond cutters
- Drilling fluid circulation
- Range of bit sizes

The *bit* is a rotating device located at the bottom of a *drill string*. It is used to cut and dislodge layers of underground rock (fig. 1). As the bit rotates, cutting structures in the form of steel teeth, inserts, diamonds, or diamond compacts (called *cutters*) chip away at the rock (fig. 2). As the rock is cut, *drilling fluid*, in the form of air, gas, water, oil-based mud, or a variety of substances, is circulated through the bit to displace the broken material (fig. 3). The small, fragmented pieces of rock, referred to as *cuttings*, travel through the *annular space* in the *borehole* back to the earth's surface.

Bits are available in various sizes. Most bits are 26 inches (660 millimetres) or less in diameter, although sizes range from 3 inches (76 millimetres) to 42 inches (1,067 millimetres). As detailed in subsequent sections of this book, a number of factors influence the size and type of bit that is selected. A thorough evaluation of these factors can help ensure the success of a drilling operation.

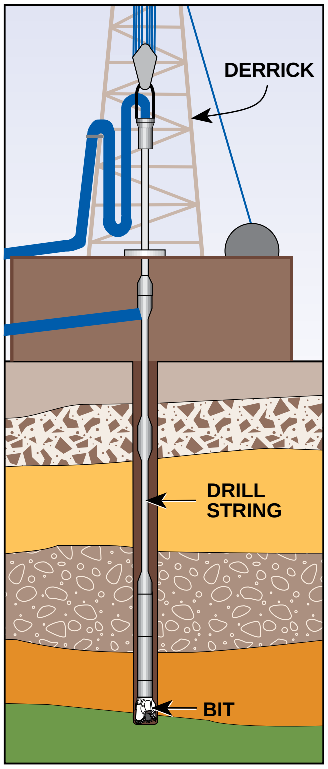

Figure 1. A bit is designed to cut through layers of rock.

Bit Selection

In this chapter:

- How formations and lithology impact bit selection
- Rate of penetration, durability, and longevity
- The importance of drilling a full-gauge hole
- The costs and benefits of high-quality bits

Factors to Consider

Whether a company is drilling a *wildcat well* (the first well constructed in a particular area) or drilling in a known oil field, it is important that a rig operator or contractor choose a bit that is most appropriate for the job. Prior to selecting a bit, the operator should consider the following:

- *Formation* and *lithology*
- *Rate of penetration* (*ROP*)
- Durability and longevity
- Gauge
- Cost

The above factors play a critical role in the selection process. Therefore, it is important for operators to become familiar with the key terms and concepts identified throughout this chapter. Moreover, all those responsible for handling a bit can benefit prior to the commencement of a drilling operation by reviewing the criteria addressed within this section.

Roller Cone Bits

In this chapter:

- History of roller cone bits
- Types of roller cone bits
- Characteristics of bit cutting structures
- Drilling fluid and hydraulics
- Bit wear and prevention

Typically, a *roller cone bit* is equipped with three hollow, cone-shaped components (fig. 6). Some roller cone bits include one, two, or four *cones*. The cones of a roller cone bit are made of metal. Rows of teeth or *inserts* line the surface of the cones. Each cone is designed to rotate, or roll, on its own axis using *bearings* that are lubricated with drilling fluid or special grease (fig. 7). As the drill string rotates, contact with the formation causes the cones to rotate.

Courtesy of Smith Bits

Figure 6. A roller cone bit

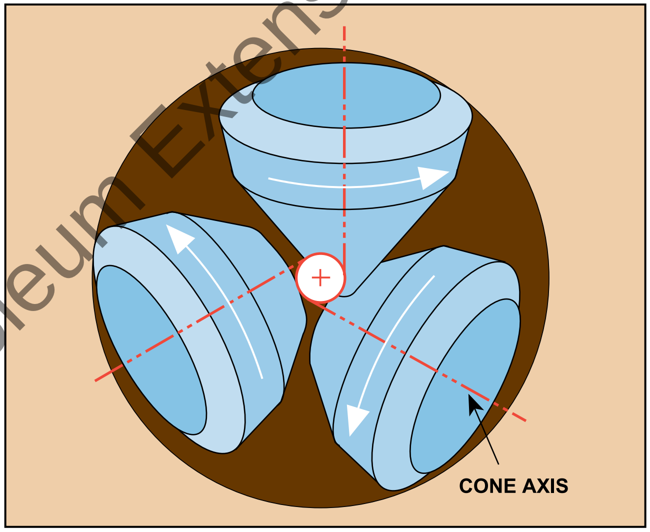

Figure 7. Each cone of a roller cone bit rotates on its own axis.

Diamond Bits

In this chapter:

- History of diamond (fixed-cutter) bits
- Properties of diamond
- Natural and synthetic diamond bits
- Drilling fluid and hydraulics
- Bit wear and prevention

Synthetic diamonds used today:

- Polycrystalline diamonds
- Thermally stable polycrystallines (TSPs)

Diamond is the hardest naturally occurring mineral on earth. It is four times harder than the second hardest mineral, corundum. Diamonds can outwear or cut anything and remain unaffected. They can cut, grind, and polish hard materials with the utmost precision, which is why it's common to find tools set with whole or crushed diamonds in industries that demand a high level of strength and accuracy. For example, diamond tools are used in the optical industry to cut glass. Surgical instruments are often assembled with diamonds, and the automobile, aircraft, and space industries all rely on diamonds to manufacture vehicles. Diamond tools would be more common in every industry and home workshop if they were not so rare and expensive to mine.

Scientists first attempted to create a low-cost, synthetic diamond in 1797. In doing so, they considered carbon. Like coal, types of ash, and soft graphite used in pencils, diamond is pure carbon. In 1954, research scientists at General Electric were the first to successfully create a diamond out of carbon. As it turns out, synthetic diamonds were more expensive to produce than natural diamonds were to mine. However, manufacturers continue to produce synthetic diamonds because demand is so great and carbon is so plentiful.

Special-Purpose Bits

In this chapter:

- Drilling with air and gas
- Jet deflection bits
- Positive displacement tools and turbine motors
- Preventing bit whirl
- Eccentric and sidetracking bits

In addition to standard roller cone and fixed-cutter bits, bits can be enhanced to serve a particular purpose. For example, some roller cone bits have extra hardfacing and tungsten carbide inserts on the shirttail. This extra layer helps prevent wear and, if protruding, absorb lateral impacts. Likewise, some fixed-cutter bits come equipped with diamond impregnated gauge protection to improve wear resistance. Extended nozzles, which help prevent balling, are a popular option for roller cone bits that are used to drill soft formations.

Adding features to a bit can prevent wear and improve drilling efficiency.

Roller Cone Bits

Air or gas serves as the drilling fluid in so-called *air bits*. Air bits come equipped with sealed bearings that prevent them from becoming clogged with cuttings. A thick layer of hardfacing on the shirttail protects these bits from the abrasive, high-velocity air or gas that is released. Manufacturers usually configure air bits with little or no skew angle, which also reduces gauge wear.

Two-cone bits might drill very soft formations faster than standard, three-cone bits. However, they might not last as long as three-cone bits.

Air bits have:
- Sealed bearings
- Hardfacing
- Minimal or no skew angle

Formations and Bit Performance

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▼
▼

In this chapter:

- Understanding formation properties
- Achieving a high rate of penetration
- How roller cone and fixed-cutter diamond bits drill
- Ways in which manufacturers improve bit performance
- Penetrating soft and hard formations

To achieve the fastest penetration rate and best interval performance at the lowest possible cost, rig operators or contractors must select a bit that is right for the job. However, a number of factors predetermine a bit's performance, including:

- Formation type
- Weight and rotary speed
- Hydraulics

Bit performance is influenced by:
- Formation type
- Weight
- RPM
- Hydraulics

The above factors affect how well a bit will operate. Therefore, rig operators must analyze these and other factors before choosing a bit.

As discussed in the subsequent sections, an understanding of the properties of formations helps inform bit selection. Moreover, analyzing formations can provide drillers with data to help ensure a successful operation. Once formations have been evaluated and a bit has been selected, it is critical that drillers and the rig crew handle it properly to avoid unnecessary wear.

WOB, Rotary Speed, and ROP

In this chapter:

- Controlling weight and rotary speed
- Adjusting operations as bits wear
- When to increase or decrease WOB
- The ROP of natural diamond and PDC bits

In order for a bit to perform at an optimum level, the WOB and rotary speed should be properly adjusted. In general, a higher rotary speed requires a lower WOB and vice-versa. Laboratory and field tests have shown that the optimum combination of weight and rotary speed varies between soft, medium, and hard formations. Moreover, different weights and rotary speeds can yield vastly different *drilling rates*. For example, by increasing the WOB of a steel-tooth bit by 30 to 40%, its rate of penetration can double. Typically, however, a rig operator or contractor does not simply want to improve the drilling rate for a short period of time. Rather, good, long-term performance should be the ultimate goal. This requires balanced parameters.

Drilling rates can improve if the bit is operated with appropriate weight and rotary speeds.

The following sections examine the WOB, RPM, and ROP of roller cone and diamond bits and provide guidelines for improving drilling efficiency in various formations.

Bit Classification

In this chapter:

- How roller cone bits are classified
- How diamond bits are classified
- Examining the features of roller cone bits
- Examining the features of diamond bits
- Understanding classification codes

The IADC has developed a standard system to classify bits. Every bit manufactured anywhere in the world has a classification code based on this system. By reading the code, the driller can evaluate bits from different manufacturers and select a bit for a particular job.

IADC provides a system for classifying roller cone bits, fixed-cutter bits, and their features.

The IADC classification system provides approximate information and does not describe hydraulics or features. Still, it is a simple and functional starting point for comparing bits from different manufacturers. For referencing purposes, this chapter includes examples of charts used by manufacturers to classify bits (tables 1–3):

- Table 1 is tailored to roller cone bits. This chart is used by manufacturers to classify the cutting structure, bearing type and gauge surfaces, and available features.
- Tables 2 and 3 are tailored to diamond bits. These charts are used to classify body material, cutter density, cutter size or type, and body style.

Dull Bit Grading

In this chapter:

- The importance of proper dull bit grading
- Grading the condition of a bit's cutting structure
- How to determine if a bit can drill a full-gauge hole
- Identifying secondary bit wear
- Understanding dull bit grading codes

Dull bit grading:
- Helps operators select an appropriate bit
- Is a form of field testing
- Applies to roller cone and fixed-cutter bits

Dull bit grading is a way of estimating the amount and location of wear on a bit. Proper dull bit grading helps inform the rig operator or contractor in a variety of ways. For example, it can help operators select a bit that is most appropriate for specific conditions, correct poor drilling practices, and make decisions that affect the cost of future drilling. Dull bit grading is a form of ongoing field testing, which benefits operators and crewmembers.

Roller cone bits and diamond (fixed-cutter) bits are graded using an IADC dull bit classification system. The system includes eight categories (table 4). Since fixed-cutter bits have no bearings, the column for bearing wear (B) will always include an X. Notably, some wear codes only apply to diamond bits while other codes are exclusive to roller cone bits.

The first four columns on the dull bit grading chart refer only to the condition of the cutting structure. For a fixed-cutter bit, column 1 (Inner Rows) refers to the cutters within the inner, two-thirds of the diameter of the bit. For a roller cone bit, column 1 refers to the entire cutting structure except for the gauge inserts or teeth. Column 2 (Outer Rows) refers to the cutters in the outer, one-third of the diameter of a fixed-cutter bit excluding any gauge cutters. Gauge cutters for a PDC bit are not included in the system as they are frequently pre-flattened to make the bit in gauge; therefore, they have an indeterminate wear.

Expenses to Consider

In this chapter:

- How rig operators analyze cost
- Factors that influence cost
- How drilling performance can minimize expenses
- High-quality bits and long-term savings
- Calculating operation costs

Rig operators or contractors often employ a break-even analysis in order to determine the cost per foot or metre to drill a hole. In doing so, they take into account the following expenses:

- Cost to operate all aspects of the rig per hour
- Cost of the bit
- Trip time, in hours
- Drilling time, in hours

Expenses associated with high-end bits can be offset if the bit proves durable over time.

The listed expenses are impacted by the bit that is selected. For example, a PDC bit might cost 15 times as much as a steel-tooth bit and four times as much as a tungsten carbide insert bit even though the bits are equal in size. However, the bit's initial cost is just one factor. Other potential costs must be considered, such as the length of time required to drill at a certain depth and the number of trips that might be necessary. A drilling contractor will have to pay more as drilling time is extended. This could result in additional expenses, including fuel, repairs, replacement, and wages. Therefore, the upfront expense associated with a PDC bit might be offset by its long-term usefulness and durability. Moreover, PDC bits are widely used and therefore economical for many applications.

Field Operating Procedures

In this chapter:

- Preparing a roller cone bit for a drilling operation
- Preparing a diamond bit for a drilling operation
- How to trip in a bit properly
- How to achieve an optimum ROP
- How to properly remove a bit from a borehole

Drilling with a Roller Cone Bit

While roller cone bits are durable, they should be handled properly by crewmembers to avoid unnecessary damage.

A roller cone bit is a durable piece of rig equipment. Still, if it is not properly handled and maintained, its life can be cut short. The following field operating procedures can assist drillers and crewmembers who are preparing to use a roller cone bit to drill a formation:

- If the packing box containing the bit is open, the threads on the bit's pin should be checked and cleaned if needed.
- The bit's serial number and type should be recorded.
- Nozzles should be checked.
- The inside of the bit should be checked for fine metallic shavings or other materials that can cause nozzles to plug.
- High-quality, clean lubricant intended for *tool joint* threads should be used on threads.
- A breaker plate, or *bit breaker*, that is appropriate for the size and shape of the bit should be used.
- The hole should be covered and the breaker placed in the locked rotary table. The bit should be screwed into the bit threads on the collar sub. The bit should be placed in the breaker and the collar or bit sub lowered over the pin.

Conclusion

Although the bit is one of several mechanisms on a rig, it serves a critical purpose during the production of oil and gas. Ultimately, it should provide the rig operator with a good rate of penetration (ROP), durability, and longevity.

As detailed in this lesson, operators or contractors are responsible for selecting a bit that is most appropriate for the job. To do so, a number of factors must be considered, particularly the properties of the formation that will be drilled. Operators can choose from a variety of roller cone and fixed-cutter bits in order to achieve optimum results. Proper handling and maintenance is equally important to avoid untimely wear.

By following operating procedures accordingly—paying particular attention to rotary speed, weight, and hydraulics—a bit should function for many hours or drilling intervals, providing rig operators with an invaluable mode for drilling economically while maximizing profits.

Appendix A

Bit wear is costly but often times avoidable. This index includes various types of wear that roller cone bits incur, possible causes and effects, and prevention tips.

Figure 32

Type of wear: Cone skidding or dragging

Possible causes: Bearing failure, failure to break in a cone adequately, a pinched bit, junk

Effects: Cone is worn flat

Prevention: Proper cleaning and maintenance, fish out junk

Figure 33

Type of wear: Cone erosion

Possible cause: Drilling fluid with abrasive particles applied at high speeds

Effects: Inserts fall out, ROP disrupted

Prevention: Adjust application of drilling fluid

Figure 34

Type of wear: Cracked cone

Possible causes: Erosion, ledge impact, impact on bottom

Effects: Cone develops cracks

Prevention: Proper application of drilling fluid, appropriate drilling practices

Appendix B

Figure Credits

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Figure	Owner	Web site
1 _ A bit is designed to cut through layers of rock.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex
2 _ Examples of cutting structures and diamond cutters	Copyright © National Oilwell Varco. All rights reserved.	www.nov.com
3 _ Circulating drilling fluid lifts cuttings.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex
4 _ Many layers of rock occur in the earth.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex
5 _ An undergauge hole has a diameter that is smaller than the bit.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex
6 A roller cone bit_	Copyright © Smith Bits. All rights reserved.	Not available
7_ Each cone of a roller cone bit rotates on its own axis.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex
8_ The inner rows of teeth on one cone intermesh in the spaces between the rows of teeth on the adjacent cone.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex
9_ A drag bit is simply two, three, or four steel blades attached to a shank.	Tim Canavan	Not available
10 A nozzle _	Copyright © National Oilwell Varco. All rights reserved.	www.nov.com
11_ Steel teeth are milled out of the cone.	The University of Texas at Austin, PETEX	www.utexas.edu/ce/petex

Glossary

A

abrasion *n*: a type of wear caused by friction between the rock material and bit.

air bit *n*: a roller cone bit that is specially designed for air or gas drilling. It is similar to a standard bit but includes sealed bearings to prevent clogging and a thick hardfacing on the shirttail to protect against abrasion from high-velocity air or gas drilling fluid. Air bits usually have 0° skew angle to minimize gauge wear.

air drilling *n*: a method of rotary drilling that uses compressed air instead of water or drilling mud as the circulating medium; called gas drilling if compressed natural gas instead of air is circulated.

alloy *n*: a substance with metallic properties that comprises two or more elements in solid solution.

annular space *n*: the space between the drill string and the wall of the hole or the casing.

annular velocity *n*: the speed at which the drilling fluid is traveling in the annulus of a well.

annulus *n*: see *annular space*.

antiwhirl bit *n*: a specially designed fixed-cutter bit. An example is a bit with a smooth pad on the bit's gauge surface, positioned so that it prevents the side of the bit from biting into the formation and initiating lateral vibration. Several antiwhirl bit designs are available.

axial force *n*: 1. the force that travels through the center line, or axis, of the cone from the formation towards the lug. 2. to reopen the borehole with the bit.

axial vibration *n*: vibration mode where energy travels up and down the axis of the drill string.

B

back rake angle *n*: in a PDC bit, the angle in degrees, between vertical (90°) and the face of the cutter.

back ream *v*: 1. to enlarge the wellbore by raising and rotating the drill string that has a reamer made up in it. Backreaming enlarges tight spots in the wellbore. 2. to reopen the borehole with the bit. Backreaming is performed when clay or salt has migrated into the well behind the bit. See *ream*.

backreaming *n*: see *back ream*.

Review Questions
LESSONS IN ROTARY DRILLING
Unit I, Lesson 2: The Bit

Multiple Choice

Pick the *best* answer from the choices and place the letter of that answer in the blank provided.

1. To begin drilling, a driller should rotate the bit, apply weight to it, and—
   a. add tungsten carbide inserts.
   b. use diamonds as cutters.
   c. forge teeth into the cones.
   d. circulate drilling fluid.
2. Undergauge holes—
   a. are too large to produce efficiently.
   b. can cause full-gauge tools to become stuck.
   c. reduce the likelihood of bit wear.
   d. are desirable because they are cost-effective.
3. Interfit keeps cutting structures—
   a. sharp.
   b. from breaking.
   c. clean.
   d. sandy.
4. Steel teeth should be—
   a. long, if a roller cone bit is drilling a harder formation.
   b. short, if a roller cone bit is drilling a harder formation.
   c. milled from industrial-grade diamonds.
   d. placed inside cones near the bearings.
5. Drilling fluid is—
   a. used to cool a bit, which heats up because of friction.
   b. always a liquid because air and gas are ineffective.
   c. optional and not required if a bit is new.
   d. formation fluid that enters the wellbore.
6. The primary disadvantage of tungsten carbide inserts is—
   a. they are not very wear resistant.
   b. they do not withstand impact shock.
   c. they cannot withstand abrasions.
   d. they do not last as long as steel teeth.

Index

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