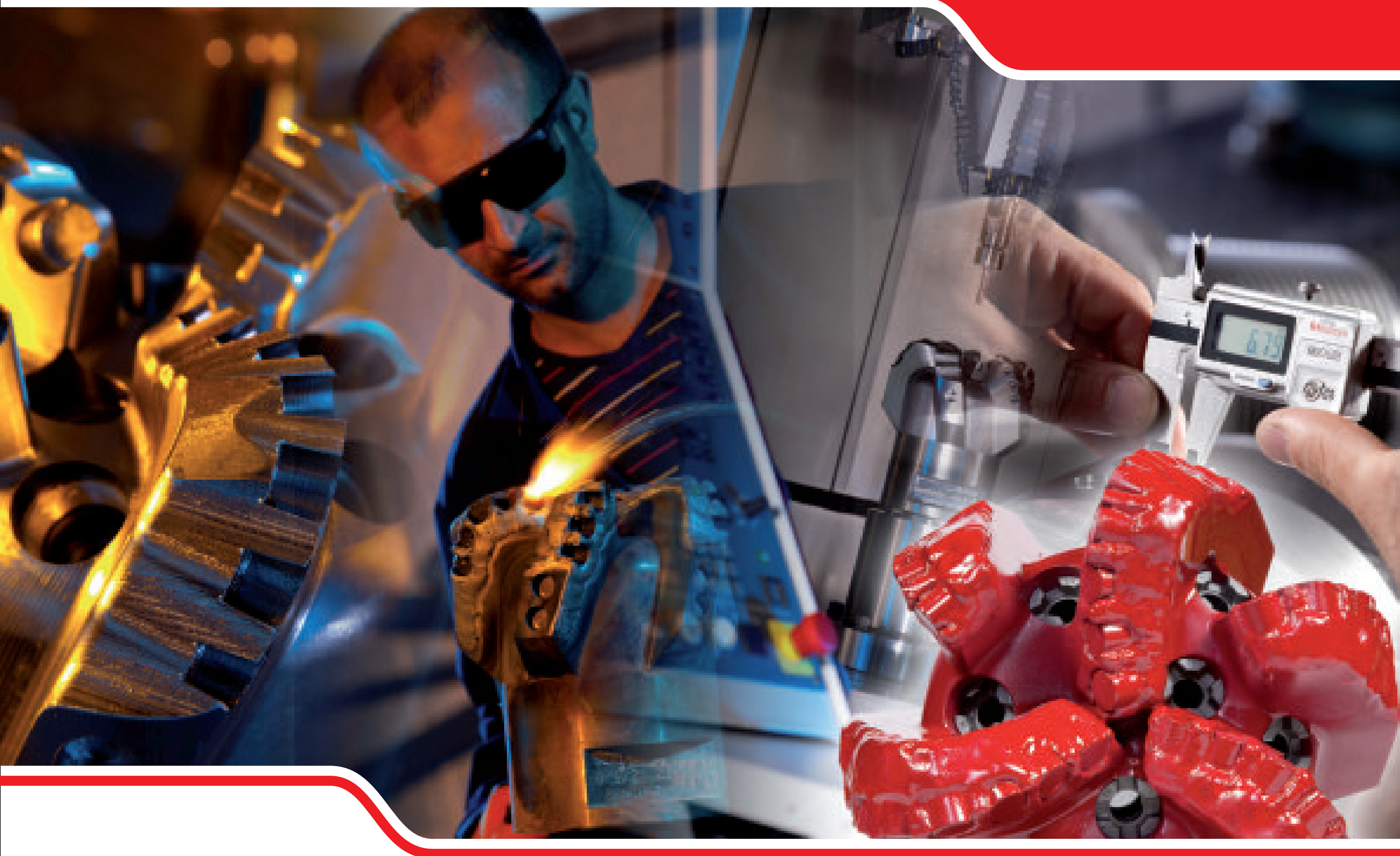
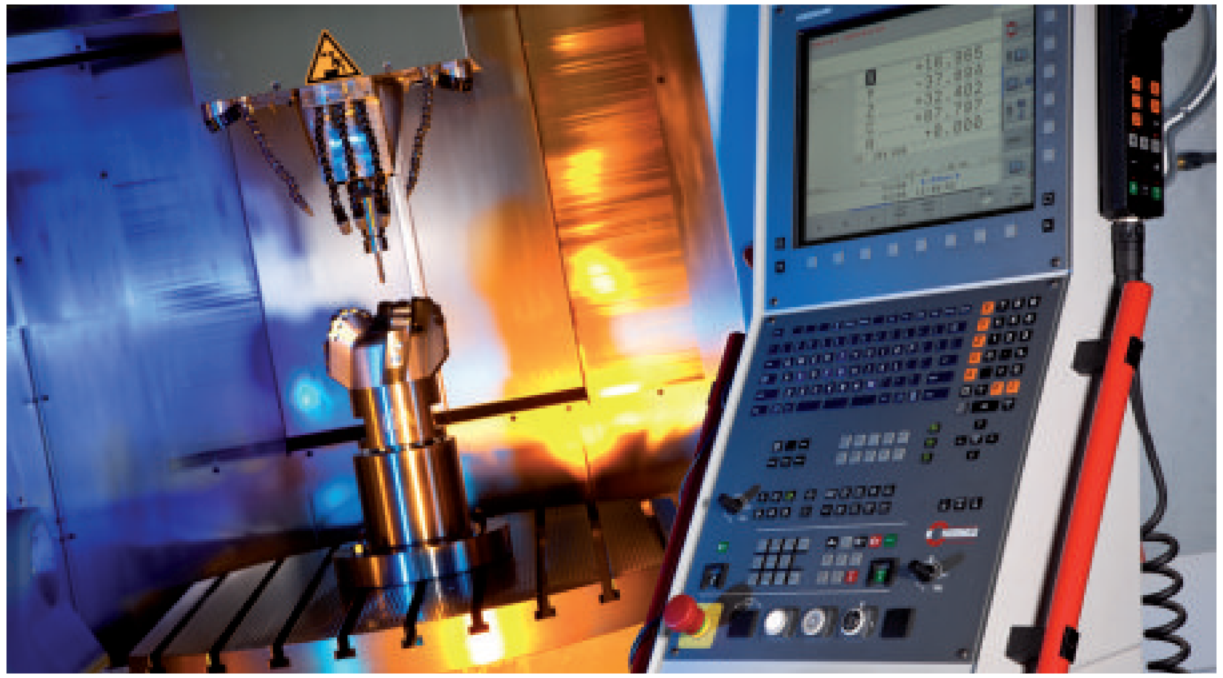
NOW you have a choice!



Hole Monster

Hole Monster



Hole Monster is committed to providing state-of-the-art steel body PDC bits to optimize drilling efficiency and lower drilling costs.

Our fully equipped manufacturing facility, well educated team of engineers and technicians that are using advanced design programs have enabled us to manufacture and supply industry's most affordable PDC bits by continually improving product performance and develop innovative solutions for the most performance driven drilling tools.

Our PDC bits have improved junkslot design for maximizing junk slot volume for better cleaning and higher ROP, short shank for steering capability, low torque cutter angles to reduce torque and increase drill string life.

HM PDC bits currently drilling oil, gas and geothermal wells with high speed, higher durability, which, in return, reduces the overall well cost.

From surface to TD, we can meet all drilling requirements by offering multiple styles of bits ranging in sizes from 2 ¼" up to 22".

Our goal is 100% customer satisfaction.

WHY PDC BITS?

PDC bits have the fixed blades with large, hard, abrasion-resistant cutters manufactured from a boned mass of microcrystalline synthetic diamonds and designed to excavate hole by shearing the formation while tricone insert bit works by crushing it.

Softer the formation and homogenous smaller the number of blades and bigger the size of the PDC cutters.

They drill very fast in soft to moderately hard formations as Sand, Shale, Clay and Siltstone.

PDC bits have the advantage that they last longer- you can usually drill shoe to shoe, eliminating tripping, and can often be rerun (with or without refurbishment) on subsequent wells, reducing the cost per foot if you have a number of wells to drill.

The PDC bit is now almost the default choice unless you can't use a PDC bit: really plastic, sticky formations or really hard formations (and PDC technology is encroaching into these areas with depth of cut limiters and the like).

In fact, as more and more drillers are only accustomed to using PDC bits, like the "top driver driller" phenomenon, we are loosing the "art" of roller cone drilling. PDC bits are essentially fire & forget: when they wear out the ROP drops and you pull them; it's very unusal for them to fall apart, whereas with roller cones, there is always the risk of dropping a cone if you push the bit a little too long!

PDC technology has come a long way in abrasive formation. The drillers doubling their footage drilled with a PDC bit (same area and sandstone formation) in only a couple of years. Such as East Texas area where the Travis Peak formation is over 2000' of consolidated sandstone. Ten years ago, a well would consist of over 20 insert bits just to get through, where now it takes 1, 2, or 3 PDC bits depending on exact location.

Overally rig time has been reduced from 90+ days on a well to 15.

Nowadays the casing equipment is PDC drillable and the cement will not ever be too hard for a PDC.

WHY STEEL BODY BIT VERSUS MATRIX BIT?

The use of steel as a material for the body of the PDC bit has numerous engineering benefits in that the high resilience of steel allows the designer to create bits with the highest possible blade off.

	Typical Yield Strength	Typical Tensile Strength	Elongation
	N/mm2	N/mm2	%
Low Carbon Steel	50	70	30.0
Infiltrated tungsten carbide	-	50	0.0

Typical mechanical properities of low carbon steel and infiltrated tungsten carbide material used for fixed cutter drilling bits

WHY HOLE MONSTER PDC BITS?

- Designed technically advanced blade profile to maximize shearing efficiency of various formation types
- Optimized body geometry and nozzle placement allows for highly effective balling mitigation, cutter cooling and cutting evacuation
- Cutter pockets and body geometry are CMC programmed from 3D scale models
- CAD/CAM Software
- Carbide hardfacing for abrasion and erosion resistance
- Excellent strength and ductility
- Reduced vibration and shock
- Increased PDC cutter life

HOLE MONSTER PRODUCT LINE

PIRANHA SERIES:

Size range from 2 1/4" upto 6 ¾" for Mining, Geothermal drilling

T-REX SERIES:

Size range from 7 1/4" upto 22" for Oil & Gas, Geothermal and Water Well drilling

Product Line	Typical Bit Sizes	API Pin Conn.	Standard PDC Cutter Size	Optional PDC Cutter Size	Standard Blade Count	Optional Blade Count
PIRANHA (PR)	2-1/4" 2-5/8" 2-15/16"	AW BW BW	8mm	13mm, 16mm	2	3
PIRANHA (PR)	3-1/2", 3-5/8", 3-7/8, 41/8" 4-1/4", 4-1/2", 4-3/4"	2-3/8 Reg	13mm	8mm	3	4, 5
PIRANHA (PR)	4-5/8", 4-7/8", 5-1/4, 51/8" 5-3/4", 5 5/8", 5-7/8", 6", 6-1/8", 61/4",6-1/2", 6-3/4"	3-1/2 Reg	13mm	16mm	5,6	3, 4
T-REX (T-R)	7-1/4", 7-1/2",7-5/8", 77/8" 8-1/2", 8-3/4"	4-1/2 Reg	16mm	13mm, 19mm	5,6	7
T-REX (T-R)	9-7/8", 10-5/8",11",12-1/4" 13-1/2",13-3/4",14-3/4"	6-5/8 Reg	16mm	13mm, 19mm	5,6	7, 8
T-REX (T-R)	15", 17 ½", 20", 22"	7-5/8 Reg	16mm	13mm, 19mm	6	7, 8





HOLE MONSTER PDC NOMENCLATURE

- **T-R** — Product Line
- **S** — Body Material (Steel)
- **6** — Blade Count
- **16** — Cutter Size mm
- **N6 / P6** — Nozzle or Port Count

EXAMPLE: T-R S 616N6 (T-Rex type, Steel body, 6 Blades, 16mm cutters, 6 Nozzles)

IADC classification : PDC bits

A	B	C	D
Bit body	Formation type	Cutting structure	Bit profile

A – Bit body

"M"	Matrix
"S"	Steel
"D"	Diamond

Example

M	Matrix
4	Medium
3	PDC 13mm
4	Long profile

B – Formation type / C – Cutting structure

B	Formation type	C	Cutting structure
1	Very soft	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
2	Soft	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
3	Soft to medium	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
4	Medium	2	PDC, 19mm
		3	PDC, 13mm
		4	PDC, 8mm
5	No code		
6	Medium hard	2	Natural diamond
		3	TSP
		4	Combination
7	Hard	2	Natural diamond
		3	TSP
		4	Combination
8	Extremely hard	2	Natural diamond
		3	Impregnated diamond

D – Bit profile

1	Short fishtail
2	Short profile
3	Medium profile
4	Long profile

Drilling Terms	
Annulus	The space between the drill pipe and hole wall or casing inside surface.
BHA	Bottom Hole Assembly.
Bit Breaker	The steel plate that locates the bit in the rotary table while it is screwed onto/made up to the drillstring.
BOP	Blow Out Preventer, a series of valves that close to seal in the well and prevent it blowing out.
Cavings	Formation that has fallen out of the well bore wall down hole.
Drill Collar	Heavy drill pipe used in the BHA to add weight.
Fishing	Attempting to recover an item out of the well bore to surface.
GPM	Gallons Per Minute.
HSE	Health, Safety and Environment.
HSI	Hydraulic horsepower per Square Inch.
Kelly	The heavy steel drive shaft with a square or hexagonal cross section that locks in the rotary table and is connected to the drillstring to transmit torque.
LCM	Lost Circulation Material.
LWD	Logging While Drilling.
MWD	Measurement While Drilling.
OBM	Oil Based Mud.
RMS	Root Mean Square (a method of averaging a signal).
RoP	Rate of Penetration, fph/mph.
Rotary Table	Device on the rig floor used to drive/rotate the kelly and support the drillstring.
RPM	Revolutions Per Minute.
RSA	Rock Strength Analysis.
PDC	Polycrystalline Diamond Compact.
POBM	Pseudo Oil Based Mud.
PPE	Personal Protective Equipment.
PSI	Pounds per Square Inch, fluid pressure.
Sliding	While directionally drilling with a motor, the rotary drive is switched off so the drillstring does not rotate and is 'slid' downhole
SPM	Strokes Per Minute.
SPP	Stand Pipe Pressure.
Spudding	Burying the bit face into material, eg: the hole bottom or casing shoe assemblies.
TFA	Total Flow Area, the sum of the cross-sectional areas of the exits of all nozzles in the bit.
Toolface	The direction the motor is orientated to in hole while sliding.
Top Drive	A torsional motor used to drive the drill string. Usually installed on the bigger rigs and can provide more power than a kelly drive.
WBM	Water Based Mud.
WoB	Weight on Bit, klbs/tonnes.

Total flow area chart

Total Flow Area (TFA) of Standard Nozzles, in2									
Number of Nozzles									
Nozzle Size, in	1	2	3	4	5	6	7	8	9
7/32	0.038	0.075	0.113	0.150	0.188	0.225	0.263	0.301	0.338
8/32	0.049	0.098	0.147	0.196	0.245	0.295	0.344	0.393	0.442
9/32	0.062	0.124	0.186	0.249	0.311	0.373	0.435	0.497	0.559
10/32	0.077	0.153	0.230	0.307	0.383	0.460	0.537	0.614	0.690
11/32	0.093	0.186	0.278	0.371	0.464	0.557	0.650	0.742	0.835
12/32	0.110	0.221	0.331	0.442	0.552	0.663	0.773	0.884	0.994
13/32	0.130	0.259	0.389	0.518	0.648	0.778	0.907	1.037	1.167
14/32	0.150	0.301	0.451	0.601	0.752	0.902	1.052	1.203	1.353
15/32	0.173	0.345	0.518	0.690	0.863	1.035	1.208	1.381	1.553
16/32	0.196	0.393	0.589	0.785	0.982	1.178	1.374	1.571	1.767
17/32	0.222	0.443	0.665	0.887	1.108	1.330	1.552	1.773	1.995
18/32	0.249	0.497	0.746	0.994	1.243	1.491	1.740	1.988	2.237
19/32	0.277	0.554	0.831	1.108	1.384	1.661	1.938	2.215	2.492
20/32	0.307	0.614	0.920	1.227	1.534	1.841	2.148	2.454	2.761
21/32	0.338	0.676	1.015	1.353	1.691	2.029	2.368	2.706	3.044
22/32	0.371	0.742	1.114	1.485	1.856	2.227	2.599	2.970	3.341
23/32	0.406	0.811	1.217	1.623	2.029	2.434	2.840	3.246	3.652
24/32	0.442	0.884	1.325	1.767	2.209	2.651	3.093	3.534	3.976
25/32	0.479	0.959	1.438	1.917	2.397	2.876	3.356	3.835	
26/32	0.518	1.037	1.555	2.074	2.592	3.111	3.629		
27/32	0.559	1.118	1.677	2.237	2.796	3.355	3.914		
28/32	0.601	1.203	1.804	2.405	3.007	3.608			
29/32	0.645	1.290	1.935	2.580	3.225	3.870			
30/32	0.690	1.381	2.071	2.761	3.451				
31/32	0.737	1.474	2.211	2.948	3.685				
32/32	0.785	1.571	2.356	3.142	3.927				

Recommended fixed cutter bit makeup torque

Recommended Makeup Torque – Diamond & Fixed Cutter Drill Bits With Pin Connections				
API Reg Connection Size, in	Bit Sub OD, in	Minimum, ft.lbf	Normal, ft.lbf	Maximum, ft.lbf
2 3/8	3	1,970	2,280	2,450
	3 1/8	2,660	3,100	3,300
	3 1/4	3,400	3,950	4,200
2 7/8	3 1/2	3,380	3,950	4,200
	3 3/4 & Larger	5,080	5,900	6,300
3 1/2	4 1/8	5,700	6,600	7,000
	4 1/4	6,940	8,050	8,550
	4 1/2 & Larger	8,400	9,850	10,500
4 1/2	5 1/2	13,700	16,600	17,000
	5 3/4	18,100	21,100	22,400
	4 1/2 & Larger	18,550	21,600	22,900
6 5/8	7 1/2	40,670	47,300	50,200
	7 3/4 & Larger	41,050	47,800	50,750
7 5/8	8 1/2	53,100	61,850	65,670
	8 3/4	63,500	73,750	78,300
	9 & Larger	68,600	79,800	84,750
8 5/8	10	96,170	102,600	108,950
	10 1/4 & Larger	107,580	114,700	121,800

Notes:
1. Recommended make-up torque dictated by all BHA components.
2. Higher makeup torque values within the above ranges are recommended when high WOB is used.
3. Box connection bits should use makeup torque values between Minimum and Normal.
4. All connections must be lubricated with a joint compound meeting API requirements.

API gauge tolerances for fixed cutter and roller cone bits

Bit size, in	Fixed Cutter, in	Roller Cone, in
6 3/4 and smaller	-0.015 – +0.00	-0.0 – +1/32
6 25/32 to 9	-0.020 – +0.00	-0.0 – +1/32
9 1/32 to 13 3/4	-0.030 – +0.00	-0.0 – +1/32
13 25/32 to 17 1/2	-0.045 – +0.00	-0.0 – +1/16
17 17/32 and larger	-0.063 – +0.00	-0.0 – +3/32

Field operating for fixed cutter drill bits

BIT PREPARATION

Bit Handling at Rig Site

- Bit cutting elements with diamond both fixed cutter and roller cone bits, are brittle and susceptible to impact damage. Care should be taken when handling or removing any bit containing diamond cutting elements.
- Do not drop the bit even if it is in the container.
- Use a piece of wood or rubber under the bit face.

Bit Inspection

- Inspect bit for integrity (cutting elements, pin connection and makeup shoulder).
- Ensure there are no foreign objects or obstructions in the internal fluid passageways.
- Verify TFA on bits with fixed TFA.
- Record bit size, type and serial number.

Nozzle Installation

- Ensure that nozzle series are correct for bit type.
- Gauge the orifice size of every nozzle to ensure proper total flow area (TFA).
- Remove the plastic plug and ensure that O-rings are properly installed and seated.
- If different size nozzles are to be used ensure that the correct sized nozzles are in the correct place. Put bigger size nozzles in the center of the bit.
- Ensure that the threads are clean and greased (any petroleumbased grease). Fixed cutter bits with matrix threads should not be greased.
- Grease the nozzle body below the threads to prevent O-ring damage.
- Screw the nozzle in by hand until snug.
- Use nozzle wrench for final tightening. Excessive force is not necessary and can damage the carbide nozzle.
- If nozzle sizes below 9/32 are to be used, recommend the use of drill pipe screens and / or a float to prevent reverse circulation plugging. Use grasshoppers if necessary.

Makeup

- Ensure that the appropriate bit breaker is with the bit. Inspect to insure good condition and that it fits properly.
- Remove the bit from the box and place face down on a piece of wood or rubber.
- Engage the bit breaker with the bit and move them onto the rotary table.
- A float above the bit should be installed, especially on extended nozzle roller cone bits, in areas that tend to plug.
- Engage the hanging box connection to the doped threads of the bit pin.
- Proper makeup for small diameter bits is to makeup by hand for several turns, then place in the bit breaker and makeup to the recommended torque.
- Uncover the rotary and locate the bit and breaker onto the breaker holder.
- Makeup applying the recommended torque.
- Makeup torque specifications are from API spec RP7G.

TRIPPING IN THE HOLE

- Identify potential problem areas before tripping. Trip slowly through BOP, doglegs, tight spots, ledges, casing shoes, cementing equipment, etc. Wash and or ream as necessary. Severe problems may require a special 'cleanup' run.
- Certain types of fixed cutter bits with low junk slot area can create higher surge and swab pressures than roller cone bits due to more restrictive annular space.
- Local knowledge/practice will typically dictate wash down and reaming procedures. Minimum recommendation is to wash down at least the last joint to bottom at reaming speed with full circulation. Preference is to ream the last stand / 90 feet at reaming speed with full circulation.

TAGGING BOTTOM

- Approach the hole bottom cautiously, monitoring WOB and torque. An increase in WOB or torque will indicate either contact with the hole bottom or fill. Fixed cutter bits will typically show an increase in torque first. Bit is on bottom when torque increases with the WOB. Difference between measured depth and contact point should be depth of fill.
- If fill is present, pick up above the fill and rotate to bottom with full circulation until bottomhole contact is assured. Regardless if fill is present, the pipe should always be reciprocated off-bottom.
- On rotary assemblies, use a maximum of 500 pounds per inch of bit diameter, 40 to 60 rpm.
- On motor assemblies, use a maximum of 500 pounds per inch of bit diameter and the minimum allowable rpm.
- Do not use high WOB when in fill. This could cause the bit to ball.
- Circulate and rotate off-bottom (as close as possible preferably less than 6 in, no more than 1 foot) enough (5 to 15 minutes, application dependent, recommend 15 min as minimum) to ensure the hole bottom is clear of fill or junk.

Field operating for fixed cutter drill bits

DRILLING CEMENT PLUGS, FLOAT EQUIPMENT AND CASING SHOES

- When using fixed cutter bits to drill out, ensure that all cementing equipment (plugs, float collars and shoes) is PDC drillable (nonmetallic, rubber, nylon, plastic or cement).
- Recommend the use of non-rotating plugs. Alternatively, it is preferable when cementing to pump some cement on top of the plug to help prevent it from rotating during drill out.
- Using the maximum allowable flow rate to assist cleaning is preferred, but may not be possible with motor assemblies.

Procedure

- Frequently raising and lowering the bit while continuing circulation and rotation will help keep the bit clear of debris. Flushing after every 1 to 2 in drilled while reciprocating 3 to 4 feet will ensure debris is removed and new material is being drilled. Should the penetration rate decrease suddenly, repeat this step until it resumes.
- Do not spud. Spudding (impacting on the hole-bottom) can damage cutting structure elements on both fixed cutter and roller cone bits. It can also damage the roller cone bearing / seal system.
- Monitor pump pressure to ensure nozzles do not become plugged.
- Change rpm if bouncing or erratic torque is encountered.

Fixed Cutter Bits

- On rotary, use the maximum flow rate with less than 6000 lbf WOB and 60-100 rpm.
- On motor assemblies, drill with less than 6000 lbf WOB and the minimum allowable rotary rpm. Local practice will dictate flow rate as a compromise is needed between providing adequate cleaning and minimum rpm.
- Maintain low and consistent torque.

Rotating Plugs

- Should a plug begin to rotate, set down on plug with no rpm
- Increase WOB until 2000 to 3000 lbs. per inch of bit diameter is reached or alternatively an increase of 300 psi over the normal standpipe occurs.
- Then begin rotation, ending with 40 to 60 rpm.
- Repeat until penetration is achieved and wiper plug is drilled.

Alternative procedure (last resort)

- Rotate bit at 20-40 rpm
- Use 500 pounds / inch of bit diameter
- Alternate using no flow rate for 1 minute to full flow for 30 seconds.

ESTABLISHMENT OF BOTTOMHOLE PATTERN

Bottomhole pattern break-in is considered to be when a new bit achieves uniform cutting structure loading.
Proper break-in is

critical to durability and ROP.

- After drilling out the casing shoe, establish the bottomhole pattern. There may be some BHA dictated WOB and rpm guidelines until the BHA is below the casing shoe. Optimization of WOB and rpm may have to wait until the BHA or some portion of the BHA has cleared the casing shoe.
- Use extra care establishing a new bottomhole pattern when following a bit with a substantially different bottomhole profile, e.g., a PDC bit following a roller cone bit or vice-versa.
- Roller cone bits typically drill a larger size hole than a fixed cutter bit. Be sure to properly establish the bottomhole pattern when following a roller cone bit in order to insure stability.
- Establishment of bottomhole pattern can be dependent upon factors such as bit design, BHA, etc.

Field operating for fixed cutter drill bits

- Although a new bottomhole pattern is created in less than a bit diameter, it is preferred to drill 3 to 5 feet before increasing WOB and rpm.
- For starting parameters, use maximum flow rate, less than 6000 lbs. WOB and 60-100 rpm.
- Maintain low and consistent torque changing operating parameters as needed.
- Take extreme care following a coring operation or bits of different types or profiles. A different existing profile can overload specific cutting elements potentially causing a premature failure

RUNNING THE BIT

Controlled Drilling

- If in or encountering a known hard or abrasive formation of short length with a dull bit, controlled drilling (sacrificing ROP) through the interval may enhance the following bit's performance. The dull condition and bit type will determine the feasibility. Monitor the ROP and torque, follow the recommendations for evaluating ROP and torque as listed below. Proceed only if ROP and increased risk is acceptable to the customer.

Deviation & Directional Control

- Deviation concerns may override optimum WOB used. Typically minimum WOB is used to control deviation on rotary assemblies.
- Monitor deviation on straight holes. Reduce WOB to maximum allowable to maintain deviation specified by customer. Monitor for vibration. Generally, increase rpm to improve ROP.
- Higher torque and higher speed changes bit walk direction by making the bit attack the formation at different angle due to higher torque. The bit tries to climb the hole wall at a different position at different torque levels. High speed on turbines can make the bit change direction completely.

Formation Changes

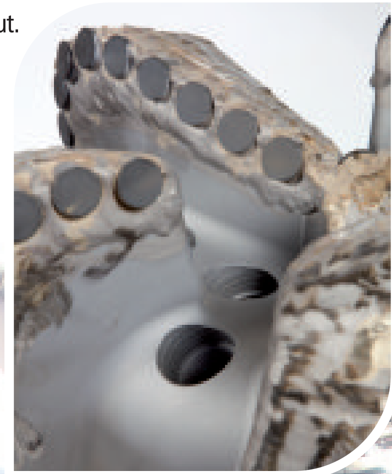
- Formation changes can instigate both torsional and lateral vibrations. Monitor and adjust accordingly.
- When anticipating a harder/more difficult formation, to prevent impact damage, reduce the rpm maintaining WOB while still in the softer formation to help prevent initiation of lateral or torsional vibrations when the hard formation is encountered. After the formation is encountered, adjust the parameters or perform a drilloff test.
- If an unknown formation (anomaly/transition) is expected, reduce the rpm and the WOB to a minimum accepted level. Establish ROP and torque baselines at these levels. Monitor ROP and torque to determine when formation has been encountered and when through the anomaly.

Operational Parameter Guidelines

- Optimum WOB and rpm determined are for a particular application and can only be continuously used in a homogeneous formation.
- There fore in intervals of various formations, ROP optimization tests will not produce the optimum weight and rotary combination.
- Drill off tests will be necessary anytime the formation changes. Typically a range of WOB and rpm combinations is derived for the interval, e.g., interbedded formations.

PULLING THE BIT

- When economics dictates.
- When ROP dictates.
- Loss of directional characteristics.
- Loss of pump pressure due to a washout.



Measurement units and drilling formulas

Standard Measurement Units				
Quantity/Property	**Units**	**Multiply By**	**To Obtain**	**Symbol**
Depth	ft	0.3048	meters	m
Weight on bit (WOB)	lbf	0.445 4.535×10^{-4}	decanewton tonne	daN tonne
Nozzle size	32nds in	0.794	millimeters	mm
Drill rate	ft/hr	0.3048	meters/hour	m/hr
Volume	barrels galUS/stroke	0.1590 3.785×10^{-3}	cubic meters cubic meters/stroke	m^3 m^3/stroke
Pump output and flow rate	galUS/min bbl/stroke bbl/min	3.875×10^{-3} an oil barrel is $0.159873 \times m^3$ exactly 0.1590	cubic meters/minute cubic meters/stroke cubic meters/minute	m^3/min m^3/stroke m^3/min
Annular velocity and slip velocity	ft/min	0.3048	meters/minute	m/min
Linear length and diameter	in	25.4	millimeters	mm
Pressure	psi	6.895 0.006895 0.06895	kilopascals megapascals bar	kPa MPa bar
Mud density	lbm/galUS	119.83	kilograms/cubic meter	kg/m^3
Mud gradient	psi/ft	22.621	kilopascals/meter	kPa/m
Funnel viscosity	s/qt (US)	1.057	seconds/liters	s/l
Apparent and plastic viscosity yield point	centipoise	1	millipascal seconds	mPa.s
Gel strength and stress	lbf/100ft2	0.4788 (0.5 for field use)	pascals	Pa
Cake thickness	32nds in	0.794	millimeters	mm
Filter loss	mm or cc	1	cubic centimeters	cm^3
Torque	ft.lbf	1.3358	newton meters	N.m

Drilling Formulas Cost per Foot (CPF)

$$CPF = \frac{\text{Bit Cost} + \text{Rig Cost (Trip Time} + \text{Drilling Time)}}{\text{Footage Drilled}}$$

Pressure Drop (△D)

$$\triangle P = \frac{\text{Flow Rate}^2 \text{ x Mud Weight}}{10{,}856 \text{ x TFA}^2}$$

Hydraulic Horsepower (HHP)

$$HHP = \frac{\text{(Bit Pressure Drop) (Flow Rate)}}{1{,}714}$$

Hole Area (Ah)

$$A_h = \frac{\pi \text{ x Hole Diameter}^2}{4}$$

Hydraulic HP per Square Inch (HSI)

$$HSI = \frac{\text{Hydraulic Horsepower}}{\text{Hole Area, in}^2}$$

Flow Rate (Q) = (Pump Stks x Output/stk)
Bit Pres. Drop ($\ddot{A}P_{bit}$) = (MWt. x Q2)/(10858 x TFA^2)
Hydraulic Horsepower (HHP_{bit}) = ($\ddot{A}P_{bit}$ x Q)/(1714)
HSI = (HHP^{bit})/(.7854 x D^2)
Jet Velocity (JV) = (.32086 x Q)/(TFA)
Impact Force (IF) = (JV)x(MWt)x(Q)x(.000516)

MWt = Mud Weight TFA = Nozzle Flow Area D = Bit Diameter

Drill collar specifications

Drill Collar Weight (Steel), lbm/ft														
Drill Collar OD, in	Drill Collar ID, in													
	1	11/4	11/2	13/4	2	21/4	21/2	23/4	3	31/4	31/2	33/4	4
2 7/8	19	18	16										
3	21	20	18										
3 1/8	22	22	20										
3 1/4	26	24	22										
3 1/2	30	29	27										
3 3/4	35	33	32										
4	40	39	37	35	32	29							
4 1/8	43	41	39	37	35	32							
4 1/4	46	44	42	40	38	35							
4 1/2	51	50	48	46	43	41							
4 3/4			54	52	50	47	44						
5			61	59	56	53	50						
5 1/4			68	65	63	60	57						
5 1/2			75	73	70	67	64	60					
5 3/4			82	80	78	75	72	67	64	60			
6			90	88	85	83	79	75	72	68			
6 1/4			98	96	94	91	88	83	80	76	72		
6 1/2			107	105	102	99	96	91	89	85	80		
6 3/4			116	114	111	108	105	100	98	93	89		
7			125	123	120	117	114	110	107	103	98	93	84
7 1/4			134	132	130	127	124	119	116	112	108	103	93
7 1/2			144	142	139	137	133	129	126	122	117	113	102
7 3/4			154	152	150	147	144	139	136	132	128	113	112
8			165	163	160	157	154	150	147	143	138	133	122
8 1/4			176	174	171	168	165	160	158	154	149	144	133
8 1/2			187	185	182	179	176	172	169	165	160	155	150
9			210	208	206	203	200	195	192	188	184	179	174
9 1/2			234	232	230	227	224	220	216	212	209	206	198
9 3/4			248	245	243	240	237	232	229	225	221	216	211
10			261	259	257	254	251	246	243	239	235	230	225
11			317	315	313	310	307	302	299	295	291	286	281
12			379	377	374	371	368	364	361	357	352	347	342

Conversion factors

Fraction to Decimal

1/64	.0156	17/64	.2656	33/64	.5156	49/64	.7656
1/32	.0312	9/32	.2812	17/32	.5312	25/32	.7812
3/64	.0468	19/64	.2968	35/64	.5468	51/64	.7968
1/16	.0625	5/16	.3125	9/16	.5625	13/16	.8125
1/64	.0781	21/64	.3281	37/64	.5781	53/64	.8281
3/32	.0937	11/32	.3437	19/32	.5937	27/32	.8437
7/64	.1093	23/64	.3593	39/64	.6093	55/64	.8593
1/8	.1250	3/8	.3750	5/8	.6250	7/8	.8750
9/64	.1406	25/64	.3906	41/64	.6406	57/64	.8906
5/32	.1562	13/32	.4062	21/32	.6562	29/32	.9062
11/64	.1718	27/64	.4218	43/64	.6718	59/64	.9218
3/16	.1875	7/16	.4375	11/16	.6875	15/16	.9375
13/64	.2031	29/64	.4531	45/64	.7031	61/64	.9531
7/32	.2187	15/32	.4687	23/32	.7187	31/32	.9687
15/64	.2343	31/64	.4843	47/64	.7343	63/64	.9843
1/4	.2500	1/2	.5000	3/4	.7500	1	.10000

English and Metric

Multiply	By	To Obtain
Acres	43,560	Square feet
Acres	0.001562	Square miles
Acres	4,840	Square yards
Barrels, water	31.5	Gallons
Barrels, water	263	Pounds
Barrels, oil (API)	42.0	Gallons
Barrels per day	0.02917	Gallons per minute
Centimeter	0.3937	Inches
Cubic centimeters	0.006102	Cubic inches
Cubic feet	1,728	Cubic inches
Cubic feet	0.03704	Cubic yards
Cubic feet	7.481	Gallons
Cubic feet	0.1781	Barrels (oilfield)
Cubic feet	28.3160	Liters
Cubic feet	0.03704	Cubic yards
Cubic feet per minute	0.4719	Liter per second
Cubic inches	16.3871	Cubic centimeters
Cubic yards	27	Cubic feet
Cubic yards	0.764555	Cubic meters
Degrees (angle)	0.01745	Radians
Degree Fahrenheit (F)	[Degree F-32] ÷ 1.8 (or x 5/9)	Degree Celsius (C)
Feet	30.48	Centimeters
Feet	12	Inches
Feet	0.3048	Meters
Feet	.0001894	Miles
Feet of water (depth)	.4335	Pounds per square inch
Feet	0.3048	Meters
Foot pounds	1.35582	Joules
Foot pounds	0.138255	Meter-kilograms
Furlongs	660	Feet
Gallons (imperial)	1.209	Gallons (U.S.)
Gallons (imperial)	4.54609	Liters
Gallons (U.S.)	3,785.434	Cubic centimeters
Gallons (U.S.)	.02381	Barrels, oil
Gallons (U.S.)	.1337	Cubic feet
Gallons (U.S.)	3.785	Liters
Gallons per minute	.002228	Cubic feet per second
Gallons per minute	34,286	Barrels per day
Grains	64.79891	Milligrams
Grains	.03527	Ounces
Inches	.08333	Feet
Inches	25.4	Millimeters
Inches of water	.03613	Pounds per square inch

English and Metric

Kilometers	3,281	Feet
Kilometers	.6214	Miles
Kilometers per hour	.6214	Miles per hour
Knots	6,080	Feet
Knots	1.152	Miles
Knots per hour	1.152	Miles per hour
Liters	.03531	Cubic feet
Liters	.2642	Gallons
Meters	3.281	Feet
Meters	39.37	Inches
Meters	1.094	Yards
Miles	5,280	Feet
Miles	1.609	Kilometers
Miles	1,760	Yards
Miles per hour	88	Feet per minute
Miles per hour	1.609	Kilometers per hour
Miles per hour	.8684	Knots per hour
Minutes	.01667	Hours
Minutes (angle)	.0002909	Radians
Minutes (angle)	60	Seconds (angle)
Ounces (fluid)	1.80	Cubic inches 5
Ounces per cubic inch	1.72999	Grams per cubic centimeter
Paschal (unit or force, pressure)	1.0	Newton per square meter
Pints	28.87	Cubic inches
Pints	.125	Gallons
Pounds	453.6	Grams
Pounds Pounds of water	.4536 .01602	Kilograms Cubic feet of water
Pounds of water	27.68	Cubic inches of water
Pounds of water	.1198	Gallons
Pounds per cubic foot	.01602	Grams per cubic centimeter
Pounds per cubic foot	16.0185	Kilograms per cubic meter
Pounds per square foot	4.88241	Kilograms per square meter
Pounds per square foot	47.8803	Newtons per square meter
Pounds per square inch	2.307	Feet of water
Pounds per square inch	2.036	Inches of mercury
Pounds per square inch	0.689476	Newtons per square centimeter
Quarts (U.S.)	57.75	Cubic inches
Quarts (U.S.)	57.75	Cubic centimeters
Quarts (U.S.)	0.946331	Liters
Radians	57.30	Degrees
Radians per second	9.549	Revolutions per minute
Square centimeters	.1550	Square inches
Square feet	144	Square inches
Square feet	.00002296	Acres
Square feet	929	Square centimeters
Square inches	6.4516	Square centimeters
Square inches	.006944	Square feet
Square miles	640	Acres
Square miles	2.59	Square kilometers
Square kilometer	247.1	Acres
Square meters	10.76	Square feet
Square meters	.0002471	Acres
Square yards	9	Square feet
Square yards	.8361	Square meters
Temperature (degrees Cent.)	1.8 (add 32 deg.)	Temp. (degrees Fahr.)
Temperature (degrees Fahr.)	5/9 or 0.5556 (subtract 32 deg.)	Temp. (degree Cent.)
Tons (long)	2,240	Pounds
Tons (metric)	2,205	Pounds
Tons (short)	2,000	Pounds
Yards	.9144	Meters
Yards	91.44	Centimeters

Buoyancy factor

Buoyancy Factor k							
Mud Density				Mud Density			
kg/l	lbm/galUS	lbm/ft^3	*k*	kg/l	lbm/galUS	lbm/ft^3	*k*
1.00	8.35	62.4	0.873	1.62	13.52	101.2	0.793
1.02	8.51	63.7	0.869	1.64	13.68	102.4	0.791
1.04	8.68	64.9	0.867	1.66	13.85	103.7	0.789
1.06	8.85	66.2	0.864	1.68	14.02	104.9	0.786
1.08	9.01	67.4	0.862	1.70	14.18	106.2	0.783
1.10	9.18	68.7	0.859	1.72	14.35	107.4	0.781
1.12	9.31	69.9	0.857	1.74	14.52	108.7	0.779
1.14	9.51	71.2	0.854	1.76	14.68	109.9	0.776
1.16	9.68	72.4	0.852	1.78	14.85	111.2	0.773
1.18	9.85	73.7	0.849	1.80	15.02	112.4	0.771
1.20	10.01	74.9	0.847	1.82	15.18	113.7	0.768
1.22	10.18	76.2	0.844	1.84	15.35	114.9	0.765
1.24	10.35	77.47	0.842	1.86	15.53	116.2	0.763
1.26	10.52	78.7	0.839	1.88	15.69	117.4	0.760
1.28	10.68	79.9	0.837	1.90	15.86	118.7	0.758
1.30	10.85	81.2	0.834	1.92	16.02	119.9	0.755
1.32	11.02	82.4	0.832	1.94	16.18	121.2	0.752
1.34	11.18	83.7	0.829	1.96	16.36	122.4	0.749
1.36	11.35	84.9	0.827	1.98	16.53	123.7	0.747
1.38	11.52	86.2	0.824	2.00	16.69	124.9	0.745
1.40	11.68	87.4	0.822	2.02	16.86	126.2	0.742
1.42	11.85	88.7	0.819	2.04	17.02	127.4	0.739
1.44	12.02	89.9	0.817	2.06	17.18	128.7	0.737
1.46	12.18	91.2	0.814	2.08	17.36	129.9	0.734
1.48	12.35	92.4	0.812	2.10	17.53	131.2	0.732
1.50	12.52	93.7	0.809	2.12	17.69	132.4	0.729
1.52	12.68	94.9	0.837	2.14	17.86	133.7	0.727
1.54	12.85	96.2	0.804	2.16	18.02	134.9	0.725
1.56	13.02	97.4	0.801	2.18	18.19	136.2	0.722
1.58	13.18	98.7	0.798	2.20	18.36	137.4	0.719
1.60	13.35	99.9	0.796	2.22	18.54	1338.7	0.717

Apparent weight = Real Weight x Buoyancy Factor

hence: Buoyancy Factor (k) $= 1 - \dfrac{\text{Mud Density}}{\text{Steel Density}}$

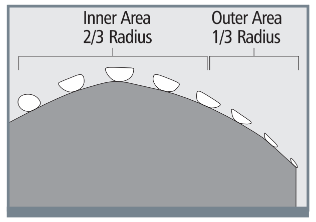
Common Problems Affecting PDC, Natural and Thermally Stable Diamond Bit Performance

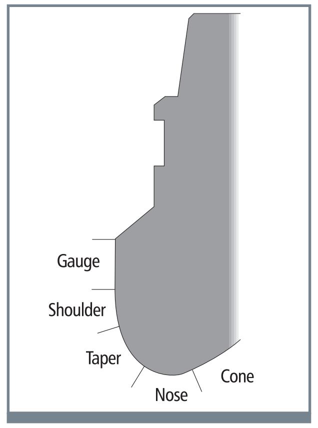
COMMON PROBLEM	PROBLEM CAUSE	PREFERRED ACTION
Difficulty going to bottom	-Previous bit under gauge. -New bottom hole assembly. -Collapsed casing. -Out of drift. -Bit oversized. -Stabilizer oversized.	-Ream with roller cone bit. When reaming to bottom, pick up and ream section again. If difficulty remains, check stabilizers. Roll casing with smaller bit. Use centre bit or reduce bit size. Gauge bit with API gauge; if not in tolerance, replace bit. Replace with correct size stabilizer.
Low pressure differential across nozzles or bit face	-Flow area too large. -Flow area too low. -Different drilling parameters than designed for. -Washout in drill string.	-Increase flow rate and correct on next bit. Increase flow rate/strokes. Change liners. Attempt to optimize, on next bit change flow area. Check bit pressure drop, drop soft line, trip to check pipe and collars.
High pressure differential across nozzles or bit face	-Flow area too small. -Excessive flow rate. -Diamond too small for formation. -Bit partially plugged (formation impaction) -Formation change. -Ring out. -Downhole motor stalled.	-Reduce flow rate, on next bit change flow area. Reduce flow area. If ROP acceptable, change on next bit. If ROP unacceptable, pull bit and use bit with correct diamond size. Check off bottom standpipe pressure. Let bit drill off, circulate full volume for 10 minutes while rotating. Check off bottom pressure again. Pick up, circulate, resume drilling at higher RPM, reset, drill off test. On and off bottom pressure test, pull bit. Refer to manufacturer's handbook.
Fluctuating standpipe pressure	-Drilling through fractured formation. -Formation breaking up beneath bit. -Stabilizers hanging up. -Equipment failure.	-If ROP acceptable, continue. Check equipment. Try combination of lighter weight and higher RPM. Check over pull. Check stabilizers on next trip. Repair equipment.
Bit won't drill	-Bottom not reached. -Stabilizers hanging up or too large. -Formation too plastic. -Establishing bottom hole pattern. -Core stump left. -Bit balled	-Check tally. Check torque, over pull. Check pressure increase flow rate, decrease/ increase bit weight, RPM. Can take up to an hour. Attempt to carefully drill ahead with low bit weight. Back off and increase flow rate, then slug with detergent or oil.
Slow RoP	-Not enough weight on bit; hydraulic lift. -RPM too low/high -Plastic formation. -Change in formation. -Overbalanced. -Diamonds flattened off. -Cutters flattened -Pressure drop too low. -Wrong bit selection.	-Increase weight on bit; -Increase/decrease rotary. Reset drill off. Reset weight. Reset drill off. Accept ROP. Pull bit. Compare beginning and present drops new bit may be required. Increase weight. Pull bit. Increase flow rate new bit may be required. Pull bit.
Excessive torque	-Excessive weight on bit. -Slow RPM. -Stabilizers too large. -Collars packing off. -Bit under gauge.	-Reduce weight and RPM. Increase rotary. Decrease weight. Check bottom hole assembly; stabilizers should be 1/32" to 1/16" under hole size. Increase flow rate and work. Pull bit.
Bit Bouncing	-Slip-stick action. -Broken formation. -Pump off force.	-Change rotary weight combination. Reduce rotary speed and weight. Increase weight. Decrease volume.

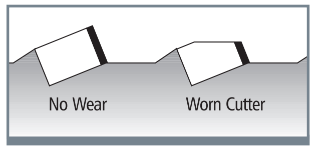
Hole Monster

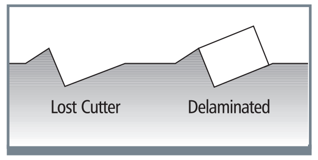
IADC Dull Grading

Cutting Structure							
Inner Rows	Outer Rows	Dull Char.	Location	Bearings/Seals	Gauge	Other Dull Char.	Reason Pulled
1	2	3	4	X	6	7	8









1 Inner Cutting Structure

2 Outer Cutting Structure

A measure of lost, worn and/or broken cutting structure.

Linear Scale: 0-8

0 - No lost, worn and/or broken cutting structure

8 - All of cutting structure lost, worn and/or broken

3 Dull Characteristics

BF - Bond Failure
BT - Broken Cutters
BU - Balled Up
CR - Cored
CT - Chipped Cutters
DL - Delaminated Cutters
ER - Erosion
HC - Heat Checking
JD - Junk Damage
LM - Lost Matrix
LN - Lost Nozzle
LT - Lost Cutters
NO - No Dull Characteristics
NR - Not Rerunnable
PN - Plugged Nozzle/Flow Passage
RO - Ring Out
RR - Rerunnable
WO - Washed Out
WT - Worn Cutters

4 Location

A - All Areas
C - Cone
G - Gauge
N - Nose
S - Shoulder
T - Taper

5 X

6 Gauge

(Measure in fractions of an inch)
I - In Gauge
1 - 1/16" Out of Gauge
2 - 1/8" Out of Gauge
4 - 1/4" Out of Gauge

7 Other Dull Characteristics

(Refer to column 3 codes)

8 Reason Pulled or Run Terminated

BHA - Change Bottomhole Assembly
CM - Condition Mud
CP - Core Point
DMF - Downhole Motor Failure
DP - Drill Plug
DSF - Drill String Failure
DST - Drill Stem Test
DTF - Downhole Tool Failure
FM - Formation Change
HP - Hole Problems
HR - Hours on Bit
LIH - Left in Hole
LOG - Run Logs
PP - Pump Pressure
PR - Penetration Rate
RIG - Rig Repair
TD - Total Depth/Casing Depth
TQ - Torque
TW - Twist Off
WC - Weather Conditions
WO - Washout - Drill String

FIXED CUTTER BITS - RING GAUGING

Any fixed cutter bit should be ring gauged prior to running in the hole. Stabilizers should also be calipered or gauged to verify they meet API-approved outside dimension tolerances as shown in the following table. Fixed cutter bits should not be larger than the nominal diameter.

API Fixed Cutter Bit Tolerances

BIT SIZE (IN.)	FIXED CUTTER BIT O.D. TOLERANCE (IN.)
6-3/4 and Smaller	-0.015 to +0.00
6-25/32 to 9	-0.020 to +0.00
9-1/32 to 13-3/4	-0.030 to +0.00
13-25/32 to 17-1/2	-0.045 to +0.00
17-17/32 and Larger	-0.063 to +0.00

A "no go" gauge is used to ensure a bit is not smaller than allowed and, as the name implies, it should not go or slip down the entire length of the bit. A "go" gauge ensures a bit is not larger than allowed and should slip down the entire bit.

Hole Monster

Sırasöğütler Mah. Çelikoğlu Cad. No:91
41700 Çayırova - GEBZE/TURKEY

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