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Writer: **Don Tuan Nguyen**

(Writer's signature)

Faculty supervisor: **Kjell Kåre Fjelde**

External supervisor(s): **Eric Paulsen**

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# Drill Bits Technology – Introduction of The New Kymera Hybrid Bit

Master's Thesis by

**Don Tuan Nguyen**

Faculty Supervisor:

**Kjell Kåre Fjelde**

External Supervisor:

**Eric Paulsen**



Faculty of Science and Technology  
Department of Petroleum Engineering  
2012

University of Stavanger, N-4036 Stavanger, Norway  
[www.uis.no](http://www.uis.no)

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# Abstract

The early concepts of hybrid bits date back to the 1930's but have only been a viable drilling tool with recent polycrystalline diamond compact technology. Improvements in drilling performance around the world continue to focus on stability and efficiency in key applications. This thesis briefly describes a new generation of hybrid bits that are based on PDC bit design combined with roller cones.

Bit related failure is a common problem in today's drilling environment, leading to inefficiencies and unnecessary downtime. Many efforts are developing to control and reduce these problems.

Kymera, the most-recent design of hybrid bit from Baker Hughes proves to be an effective solution in highly interbedded and hard formations. This innovative technology has shown in field test runs presented in this thesis that it can perform much better in footage drilled, torque fluctuations, rate of penetration, tool face control and dull condition than conventional bits.

The introduction of this unique solution brings new opportunities to improve performance in potentially difficult applications. However, the concept is still under a testing phase and continues to develop. With the rapid acceleration in technology, the Kymera could be a game-changing drill bit and obliterate conventional bits in the future.



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# 1 Introduction

The drilling bit is unquestionably one of the most critical and important item of equipment used in a drilling assembly. Selecting the correct bit for each section of the well, influences how fast the section can be drilled and how severe downhole problems may be.

Drag bits were used to drill oil wells in the early days. It was soon realized that these “fishtail” bits didn’t manage to penetrate many of the formations overlying deeper oil and gas reservoir. The drag bit had advantages such as no moving parts and effective shear cutting action of the rocks, but the cutter technology wasn’t good enough to tolerate extremely high temperature and abrasive formations. In the early 1900’s, the roller cone bit was introduced by Howard Hughes Sr. and replaced the drag bit as a more enduring tool to drill in hard rocks. This bit consisted of two cones that didn’t mesh and had a tendency of bit balling in shale and other plastically behaving rocks. The bit was redesigned in the 1920’s with meshing teeth that resulted in self-cleaning and was much more effective. Three cones were introduced in the new design with case hardened steel teeth appropriate to drill both soft and hard formations. However, General Electric Company continued to test the drag bit with new cutting structure due to its advantages compared to rolling cutters. The introduction of polycrystalline diamond compact cutting structure in the 1970’s made the drag bit competitive with the roller cone and diamond bits [4]. Both the roller cone and PDC bit have their own distinctive advantages in different applications. This means that a combination of the two bit designs as a new hybrid bit could offer an outstanding performance.

The first prototype of a hybrid bit was researched and patented in the early 1930’s by Scott L. Floyd, but was deemed impractical because the fishtail part of the bit would wear prematurely. This resulted in a reduction of the ROP to less than what was achieved by a single roller cone bit. The concept of hybrid bit continued to develop with a variety of changes in design with mixed results mainly due to structural imperfection and lack of durability in the first generation of polycrystalline diamonds. With recent advances in PDC cutter technology, it was again viable to combine the best features of conventional bits to drill in applications that constantly fluctuate between hard and soft formations [26]. Baker Hughes’ Kymera hybrid drill bit design was developed in 2009, and successful field tests around the world have shown that this new concept may be the new generation of drill bits.

The purpose of this thesis is to establish a comparison of conventional bits, mainly roller cone and PDC, with the new Kymera hybrid bit. In each different bit types, their technology and characteristics will be presented. Subsequently, parameters for selecting drill bits in will be explained prior to the presentation of Kymera.

The main objectives of this project are:

- Present each type of drill bits
- Explain the fundamental characteristics of each type
- Explain the parameters for using drill bits
- Introduce the new Kymera hybrid bit
- To present field tests
- To draw conclusions about whether the Kymera could replace conventional bits in all or some applications

## 2 Drill Bits Technology

Drill bits are the most refined tool in a rotary rig system and are specialized for every condition of drilling than any other tool on the rig. Mainly two types of bits are used in drilling today:

- Fixed cutter bits
- Roller cone bits

Fixed cutter bits include the early types of drill bits, which looked like a fishtail and had steel as cutting structure. These were called drag bits or sometimes “fishtail” bits. A PDC bit is the new generation of drag bits with much improved technology since the old types. The diamond bit is also a subtype of fixed cutter bits.

The roller cone bits consist of two types:

- Milled tooth/steel tooth
- Tungsten carbide inserts

The first type is basically a rolling cutter with teeth milled from a solid piece of steel while the latter has chemically processed wear resistant teeth pressed into the cones.

Information about the nature of the lithology must be known to select the proper bit for each well. This data are usually obtained by studying nearby offset wells. The efficiency and performance of a drill bit varies by the formation type to be drilled. Formation hardness is classified as following:

	<b>Very soft</b>	<b>Soft</b>	<b>Medium</b>	<b>Hard</b>
<b>UCS</b>	< 5000 psi	< 10 000 psi	< 15 000 psi	< 25 000 psi

## 2.1 Drag Bits

The drag bit (**Figure 2.1**) was the earliest type of fixed cutter bits in drilling with sharpened steel as cutting structure. The simple bit structure of steel could only be used in soft formations, not hard formations. Drag bits were basically used in applications such as water wells, mining, geothermal, environmental or exploration drilling.

The basic design of drag bit includes:

- Number and shape of cutting blades
- Cutting elements
- Size and location of water courses
- Metallurgy



**Figure 2.1**  
Drag bit [16]

An advantage of drag bits over roller cone is that they do not have any moving parts, which is extremely important in small holes where space is limited when designing strength into both the cutter elements and bearings needed for a rolling cutter. The chances for bit breakage or junk left in the hole are reduced without moving parts. Removing junk from a previous bit can lead to more trip time and hence loss of rig time. Relative to roller cone bits, the drag bits perform best in soft and unconsolidated formations, such as sand or clay. As the formations become harder and more abrasive, the bit wear increases and the drilling rate decreases rapidly. Problems will occur when drilling in soft formations because the cuttings may stick to the blades and reduce the effectiveness. Placing a hydraulic jet so that drilling fluid cleans the blades properly will reduce the problem [4,14].

## 2.2 Polycrystalline Diamond Compact Bits

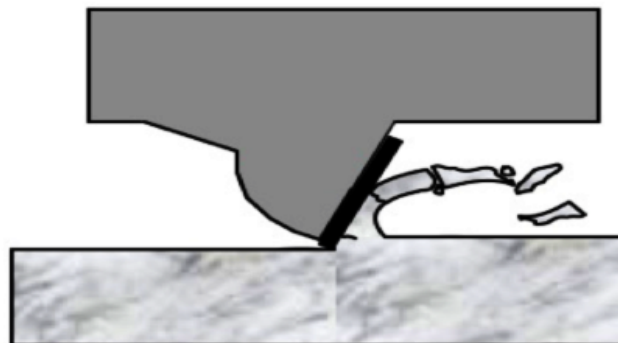
A polycrystalline diamond compact bit is a new generation of the old drag bit. The bit is designed to break the rock in shear (**Figure 2.3**) and not crushing the formation as with a roller cone bit. This requires less energy and thus less weight on bit resulting in less wear on the drill string.

The PDC bit design is influenced in nine variables [27]:

1. Bit body material
2. Bit profile
3. Gauge protection
4. Cutter shape
5. Concentration of cutters
6. Location of cutters
7. Cutter exposure
8. Cutter orientation
9. Hydraulics



**Figure 2.2**  
Genesis™ XT PDC bit  
(Source: Baker Hughes Tools)



**Figure 2.3**  
PDC bit work principle [30]



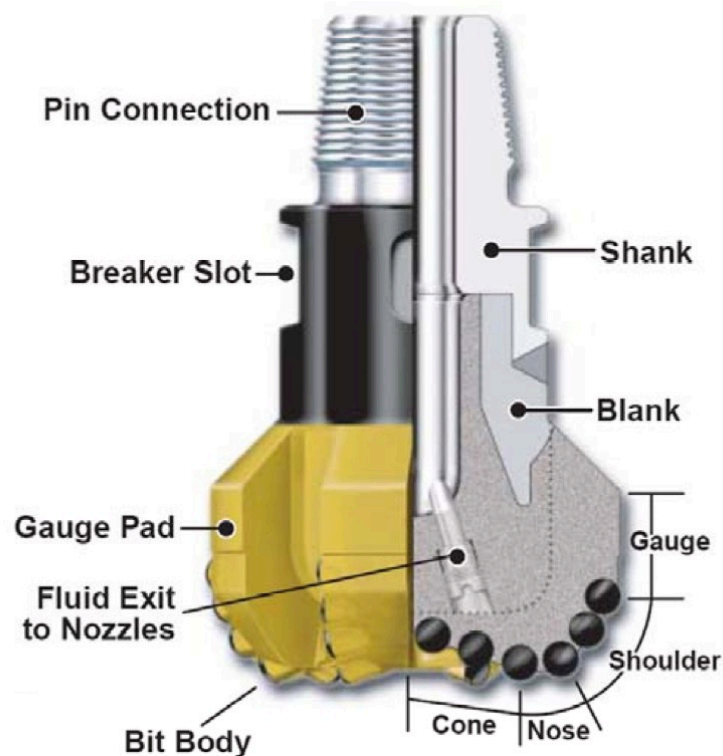
## 2.2.1 Bit Design

The PDC bit design has an advantage because there are no bearings to wear out or broken cones that may cause junk in hole. The bit has a long and extended gauge with cemented tungsten carbide wear pads to help maintain gauge.

Body material consists of two types:

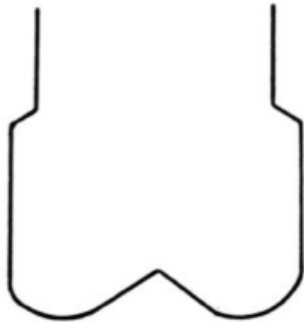
1. Heat-treated alloy steel
2. Tungsten carbide matrix

Steel body is less durable and resistant to erosion by the drilling fluid than matrix body bits. This type of bits uses stud cutters, which are attached to the body by fitting. Tungsten carbide body is manufactured in a similar process as diamond bits. That allows more complex profiles to be obtained. Because of high temperatures when making the matrix body, it is not possible to insert cutting elements until after the furnacing of the body or the compact diamonds will be destroyed.

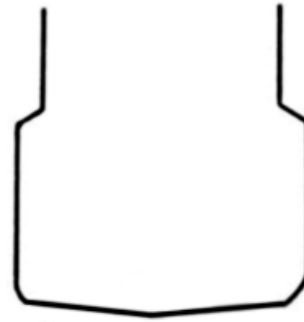


**Figure 2.4**  
PDC bit terminology [16]

The bit profile is an important design feature of PDC bits. A PDC bit usually has a double cone profile (**Figure 2.5**) and the diamond bit uses shallow cone profile (**Figure 2.6**). Double cone profile allows more cutters near the gauge and will control hole deviation while shallow cone profile affords less area for cleaning, but drills faster due to more direct loading of cutters on the bit face. For gauge protection in steel body bits, tungsten carbide inserts are placed near the edges. Matrix body bits utilize natural diamonds for gauge protection.



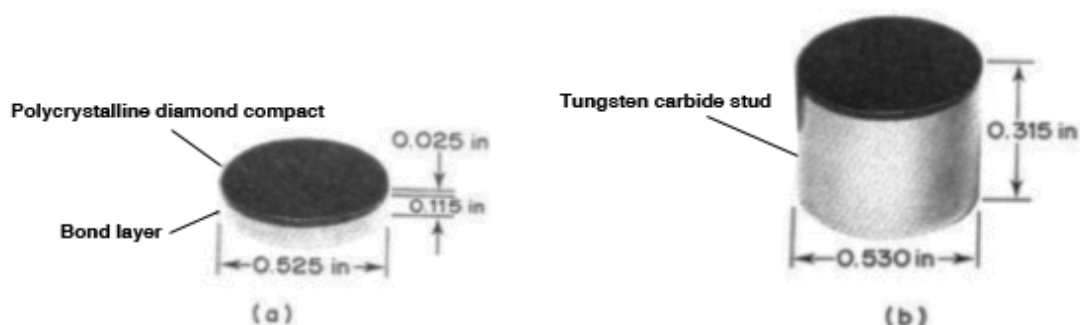
**Figure 2.5**  
Double cone bit profile [27]



**Figure 2.6**  
Shallow cone bit profile

## 2.2.2 Cutters

A PDC bit has a great amount of cutters also called drill blanks (**Figure 2.7**). They are made by bonding a layer of synthetic polycrystalline diamond to a cemented tungsten carbide substrate in a high pressure and high temperature process. This process produces a blank that has the hardness and wear resistance of a diamond. The blanks are self-sharpening meaning that small, sharp crystals are exposed as each blank wears. They are bonded to tungsten carbide studs and then attached to the bit body [4].



**Figure 2.7**  
Drill blanks [24]:  
(a) Polycrystalline diamond compact and bond layer; (b) Tungsten carbide stud.

The PDC cutters are normally produced in three basic shapes:

1. Cylindrical
2. Chisel
3. Convex

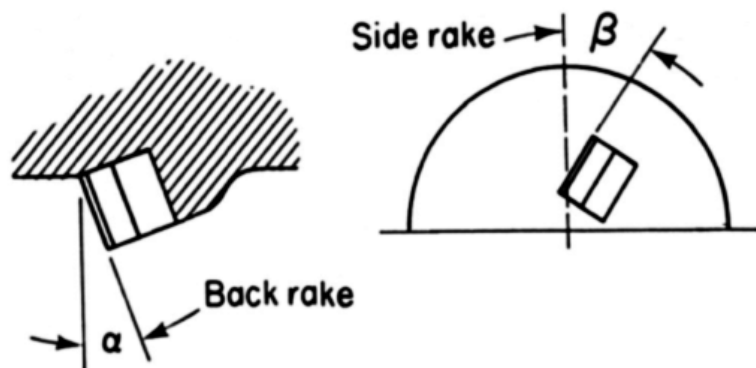


**Figure 2.8**  
PDC insert shapes [25]

High concentration of cutters will extend bit life, but the penetration rate decreases due to the difficulty of cleaning the areas between the cutters. Field experience and computer models are used to locate cutters for maximum performance and minimum wear. Increased cutter exposure will increase ROP, but it will make the cutter more vulnerable for failure. The cutter orientation is explained by back and side rake angles as shown in **Figure 2.9**. Back rake angle between  $0^\circ$  and  $25^\circ$  is aggressive on the formation and directly affects ROP. This can also lead to torsional vibrations. Higher back rake angle is less aggressive and makes the ROP decrease as the resistance to cutting edge damage increases. A very unaggressive bit can result in poor depth, making the bit unstable and liable to whirl. The side rake angle assists in hole cleaning by mechanically directing cuttings towards annulus [24].

The cutters are arranged in one of three patterns:

1. Open face – cutters on the face of the bit
2. Ribbed pattern – cutters on the ribs
3. Bladed pattern – cutters on the blades



**Figure 2.9**  
Cutter orientation [27]

### 2.2.3 Hydraulic Calculations

Bit hydraulics is a critical feature when penetrating into the formation and for carrying the broken rocks to the annulus. It is well established that cleaning the bottom of the hole and bit cutters is vital for the drilling performance. A PDC bit usually has six to nine jet nozzles to obtain proper hydraulics. Nozzle velocity is important and should be calculated to optimize the hydraulic properties. This can be done by the equation [4]:

$$V_n = \frac{418.3 \times Q}{\sum d_j^2}$$

$V_n$  = Nozzle Velocity (ft/sec)

$Q$  = Flow Rate (gal/min)

$d_j$  = Nozzle size (in 32nds of an inch.)

The nozzle velocity is usually 225 ft/sec, but can be much greater in many occasions.

Other important components that include in the hydraulic system are [4]:

- Drilling fluid characteristics – Mud weight (lb/gal), Yield point (lbs/100ft<sup>2</sup>) and Plastic viscosity (cps)
- Pressure loss through jet nozzles
- Total flow area (TFA)

Equation for pressure losses at the bit:

$$P_b = \frac{MD \times Q^2}{10858 \times TFA^2}$$

Compared to roller cone bits, PDC bits have more than three nozzles to clean the bit uniformly. Bit size and cutter design determine the number of nozzles and their orientation. Hydraulic requirements in various drilling applications will determine the TFA of the nozzles. TFA is calculated as following:

$$\left( \frac{JetSize^2}{64} \times \pi \right) \times \text{Number of nozzles}$$

A list of various TFA values is shown in **Figure 2.10**:

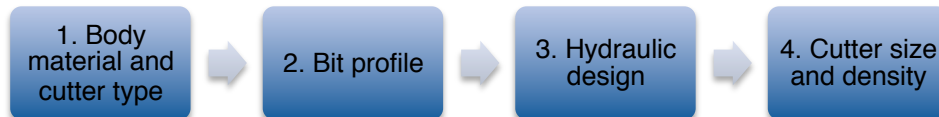
Nozzle Size*	Number of Nozzles									
	1	2	3	4	5	6	7	8	9	10
7	.0376	.0752	.1127	.1503	.1877	.2255	.2631	.3007	.3382	.375
8	.0491	.0982	.1473	.1963	.2454	.2945	.3435	.3927	.4418	.4909
9	.0621	.1242	.1864	.2485	.3106	.3728	.4249	.4970	.5591	.6213
10	.0767	.1534	.2301	.3060	.3835	.4602	.5369	.6136	.6903	.7670
11	.0928	.1856	.2784	.3712	.4640	.5568	.6496	.7424	.8353	.9281
12	.1104	.2209	.3313	.4418	.5522	.6627	.7731	.8836	.9940	1.045
13	.1296	.2592	.3889	.5185	.6481	.7777	.9073	1.0370	1.1666	1.2962
14	.1503	.3007	.4510	.6013	.7517	.9020	1.0523	1.2026	1.3530	1.5033
15	.1726	.3451	.5177	.6903	.8629	1.0354	1.2080	1.3806	1.5532	1.7258
16	.1963	.3927	.5890	.7854	.9817	1.1781	1.3744	1.5708	1.7671	1.9634
18	.2485	.4970	.7455	.9940	1.2425	1.4910	1.7395	1.9880	2.2365	2.4850
20	.3068	.6136	.9204	1.2272	1.5340	1.8408	2.1476	2.4544	2.7612	3.0680
22	.3712	.7424	1.1137	1.4849	1.8561	2.2273	2.5986	2.9698	3.3410	3.7122

\* (Nozzle size in 32nds of an inch.)

**Figure 2.10**  
TFA values of common nozzle sizes [1]

### 2.2.4 IADC Fixed Cutter Classification

The International Association of Drilling Contractors adopted a new method for classifying all fixed cutter bits in 1987 [33]. This classification system describes the design features of the bits by means of a four-character code:



1. The first code is alphabetic and defines the body material and cutter type of the bit. Matrix body means that the bit is made of tungsten carbide. The code can be:

M	PDC matrix body
S	PDC steel body
D	Natural diamond matrix body
T	TSP matrix body
O	Other

2. The second code is numerical and describes the bit profile:



1. Long taper deep cone



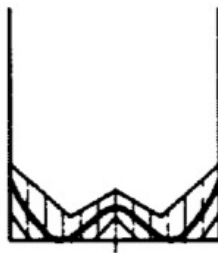
2. Long taper medium cone



3. Long taper shallow cone (Parabolic)



4. Medium taper deep cone



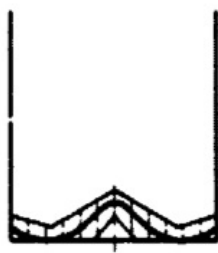
5. Medium taper deep cone



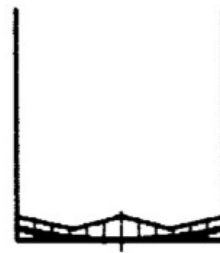
6. Medium taper shallow cone (Rounded)



7. Short taper deep cone (Inverted)



8. Short taper medium cone



9. Short taper shallow cone (Flat)

3. The third code describes the hydraulic design of the bit:

	Changeable jets	Fixed ports	Open throat
Bladed	1	2	3
Ribbed	4	5	6
Open faced	7	8	9

Alternative codes:

R	Radial flow
X	Cross flow
O	Other

4. The fourth code in the IADC classification system explains the cutter size and density:

		DENSITY		
		Light	Medium	Heavy
SIZE	Large	1	2	3
	Medium	4	5	6
	Small	7	8	9

Examples of PDC bit code:

BIT No.	IADC Code
X	M454

This is a PDC bit with matrix body and double cone profile. The hydraulic system of the bit is ribbed with changeable jets. The cutter sizes and density are medium.

BIT No.	IADC Code
Y	S914

This is a PDC bit with steel body and short taper and shallow cone profile. The hydraulic system of the bit is bladed with changeable nozzles. The cutter sizes are medium with light density.

The IADC classification is a universal system for identifying drill bits. However, many companies have their own system for classifying bits and inconsistency may exist. Also, in the industry the IADC classification is more used for roller cones than fixed cutter bits.



## 2.2.5 IADC Fixed Cutter Dull Bit Grading

In 1987 the International Association of Drilling Contractors published a dull bit grading procedure, which applied for all fixed cutter bit types. This system was revised with some minor changes in 1992 as a result of improvements in bit technology. The new procedure is presented in the table [9]:

CUTTING STRUCTURE							
Inner Rows	Outer Rows	Dull Char.	Location	Bearing / Seals	Gauge	Other Dull Char.	Reason Pulled
1	2	3	4	X	6	7	8

### Columns 1 and 2

A linear scale of 0 → 8 is used to describe the condition of the cutting structure for inner and outer row. Inner row is 2/3 of the cone radius from the center where the first cutters start and outer row are 1/3 of the remaining radius.

0	No lost, worn or broken cutters
1	
2	
3	
4	
5	
6	
7	
8	All of cutting structure is lost, worn or broken

### Column 3

This column describes the dull characteristics of cutters with these codes:

BF	Bond failure	NO	No dull characteristics
BT	Broken cutters	NR	Not rerunnable
BU	Balled up	PN	Plugged nozzle
CR	Cored	RO	Ring out
CT	Chipped cutters	RR	Rerunnable
ER	Erosion	WO	Washed out
HC	Heat checking	WT	Worn cutters
JD	Junk damage		
LM	Lost matrix		
LN	Lost nozzle		
LT	Lost cutters		

**Column 4**

This column describes the location of the dull characteristics on the bit with these codes:

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

**Column 5**

This column describes the condition of the bearing or seals of the bit, but this is for roller cones only and does not apply for fixed cutters. The letter “X” is usually put in this column.

**Column 6**

This column describes the gauge wear of the bit or how many inches the bit is out of gauge.

- I In gauge
- 1 1/16”
- 2 2/16”
- 3 3/16”
- 4 4/16”
- 5 5/16”
- etc.

**Column 7**

This column describes other dull characteristics and refers to column 3 codes.

**Column 8**

The last code indicates what reason the bit was pulled or run terminated.

- |     |                             |    |                     |
|-----|-----------------------------|----|---------------------|
| BHA | Change bottom hole assembly | HR | Hours on bit        |
| DMF | Downhole motor failure      | PP | Pump pressure       |
| DSF | Drill string failure        | PR | Penetration rate    |
| DST | Drill stem test             | TD | Total depth         |
| DTF | Downhole tool failure       | TQ | Torque              |
| LOG | Run logs                    | TW | Twist-off           |
| LIH | Left in hole                | WC | Weather conditions  |
| RIG | Rig repair                  | WO | Washout drillstring |
| CM  | Condition mud               |    |                     |
| CP  | Core point                  |    |                     |
| DP  | Drill plug                  |    |                     |
| FM  | Formation change            |    |                     |
| HP  | Hole problems               |    |                     |

Examples of PDC bit grading:

IADC GRADING							
HCC 12 ¼" QD606X PDC Bit							
I	O	D	L	B	G	O	R
1	1	WT	A	X	I	NO	TD

The grading indicates that the bit had minimal worn cutters both at inner cutting and outer cutting structure. The dull characteristics were mainly worn cutters in all areas. The gauge showed no wear and no other dull characteristics were observed. The bit was pulled after reaching total depth.

IADC GRADING							
HCC 12 ¼" QD507X PDC Bit							
I	O	D	L	B	G	O	R
2	2	CT	N	X	I	BT	DTF

The grading of this bit showed some worn cutters both at inner and outer row. The worn cutters were identified as chipped cutters at nose area of the bit. The gauge was “in gauge”. Other dull characteristics in this bit grading include broken cutters and the reason for pulling out bit was due to downhole tool failure.

## 2.2.6 Drilling Parameters

PDC bits have been recognized as a viable tool for effective drilling, but certain precautions should be taken in order for the bit to be as efficient and economical as possible. The following drilling parameters is taken from a drilling engineering learning course in Baker Hughes [4]:

1. Removing the bit: Bit grading must be executed when the bit is out of the hole. The bit should be inspected for any major damage. If junk is left in the hole, then it must be cleaned properly before running a new bit.
2. Picking up new bit:
  - a) Handle it carefully when preparing a new bit
  - b) The interior of the bit should be inspected
  - c) Proper bit breaker should be used to make up the bit (bit breaker is a special tool to prevent the bit from turning while the bit sub on top of it is tightened or loosened)
3. Tight spots: Try to avoid running the bit through a tight spot as it may damage the gauge cutters.
4. Reaming: If reaming is necessary, pick up Kelly and run maximum flow rate. Rotary speed should be approximately 60 rpm and drilling through a tight spot should be done slowly.
5. Near bottom of hole:
  - a) When near bottom, the last joint should be washed down at full flow to clean the bottom of the hole to avoid plugging the bit with fill.
  - b) To locate the bottom of hole: Observe the torque. A sudden increase in torque indicates that the bit has reached the bottom due to cutting action of PDC bits.
  - c) When the bottom of the hole has been reached, lift the bit 1-2 feet off the bottom. Circulate and rotate for a couple minutes to assure that the bottom is clean.
6. Ready to drill: Bring the rotary speed up to 60 rpm and approach the bottom. Lightweight should be used when cutting a new hole pattern.
  - a) Drill at least 1 foot of new hole before looking for optimum weight and rotatory speed for drilling.

b) The bit will drill quickly with lightweights in soft formations. The rotary speed should be increased until it reaches its fastest rate.

c) It will take much longer to drill in harder formations. Adding weight too quickly may damage the cutters. When the bottom hole pattern is drilled, add weight and watch the torque indicator for possible problems.

7. Rotary speed: Use as much as possible without damaging the rest of the drillstring.
8. On-bottom torque: Torque should approach what is experienced with roller cone bits in earlier sections. If there is no torque buildup, the formation may not be suitable for PDC bits.
9. After each connection: The bit should be washed back down to the bottom. Dropping and the drillstring suddenly may damage the bit.
10. Changing formations: When the formation changes, the PDC bit, respond dramatically. If the ROP suddenly decreases or the torque increases, a change in WOB and ROP will help.
11. Pull the bit: The bit should be pulled when the cutters wear to a point where it does not cut formation.

Indications of wear on the outside of the bit:

- Sudden decrease in penetration rate and torque
- Increase in stand pipe pressure

Indications of wear on the gauge:

- High on-bottom torque with little WOB
- Decrease in penetration rate

## 2.2.7 PDC Bit Specifications

The following example of PDC bit specification is taken from Baker Hughes’ internal webpage:



**Reference Photo:** 8-1/2 in. (215.9mm)  
HC408Z

Product Specifications	
IADC:	M433
Number of Blades:	8
Cutter Quantity (Total, Face):	53, 41
Primary Cutter Size	.529 in (13.4 mm)
Number of Nozzles:	4
Nozzle Type:	SP
Fixed TFA	0 in <sup>2</sup> (0.0 mm <sup>2</sup> )
Gauge Length	2.5 in (63.5 mm)
Junk Slot Area	11.6 in <sup>2</sup> (74.8 cm <sup>2</sup> )
Bit Breaker:	010500080,015154057,123202129,123203583
Connection:	4-1/2 API REG
Makeup Torque:	
5 1/2" Bit Sub	12.5 - 13.7 kft-lb (17.0 - 18.6 kNm)
5 3/4" Bit Sub	16.5 - 18.0 kft-lb (22.4 - 24.4 kNm)
6"+ Bit Sub	17.6 - 19.5 kft-lb (23.9 - 26.4 kNm)
Reference Part Number:	N6561
Status:	M

### Operating Recommendations\*:

Hydraulic Flow Rate:	300 - 750 gpm (1150 - 2850 lpm)
Rotation Speed:	For Rotary and Motor Applications
Max. Weight On Bit:	37 klb (16 tn or kdaN)

**Figure 2.11**  
8 1/2-in HC408Z PDC bit specification  
(Source: Baker Hughes Tools)

### Classification:

This is a standard PDC bit with matrix body and medium taper deep cone profile. The hydraulic system is bladed with open throats. Cutter size is large with heavy density.

### Nozzles:

This bit is manufactured with four Baker Hughes Super Performance™ technology nozzles.

### Gauge:

The gauge length is 2.5-in.

### Rotary speed:

The bit is suitable for rotary steerable systems and positive displacement mud motors.

### WOB requirements:

Maximum weight on bit allowed is 16 tn.

## 2.3 Diamond Bits

When the diamond bits were introduced in the early days, the intention was to drill extremely hard formations where other bits struggled. The diamonds at that time were very expensive and thus barely economical to apply in oil drilling. A new and improved technique for manufacturing diamond bits was developed. This resulted in better performances and reduced the cost but was still much more expensive than the roller cone bits. The bits are normally used in the hardest formations where long bit runs are required in order to reduce trip time [4].



**Figure 2.12**  
Natural diamond bits  
(Source: Baker Hughes Tools)

A diamond bit consist of three parts:

1. Diamonds
2. Matrix
3. Shank

The diamonds are kept in place by the matrix, which is bonded to a steel shank. The matrix is powdered tungsten carbide infiltrated with metal bonding material. Tungsten carbide is used for its wear and erosion resistant properties. The shank of steel gives the bit structural strength and makes a suitable means to attach the bit to the drill string.

### 2.3.1 Diamonds

The cutting elements in a diamond bit consist of a large number of small diamonds geometrically distributed across a tungsten carbide body. Diamonds are the hardest mineral found on earth and have the highest value possible for mineral hardness. Thermal conductivity of diamonds is also the highest of any mineral and allows the diamond to diverge heat very quickly. The diamonds used in drilling are of natural origin and have from 7 to 15 carat per stones. They are very resistant to abrasion and heat, high in compressive strength but are low in tensile strength [4,27].

There are three classifications of diamonds [4]:

1. Single crystal: These diamonds are usually translucent, shiny and come in geometrically regular shapes.
2. Coated: These diamonds have a heavy surface coating, which is usually greenish or grayish in color. They are rounded in shape.
3. Carbonado: The majority of these diamonds is black in color and has a noncrystalline structure.



**Figure 2.13**

Natural diamonds

(a) Single crystal diamond [29]; (b) Coated diamonds [12]; (c) Carbonado diamond [10].



### 2.3.2 Thermally Stable Polycrystalline

A TSP cutter is made of the same polycrystalline diamond compact material as the PDC bit. The main difference is that the drill blanks are not bonded to a stud. The bonding material in a PDC bit is the weakest part of the cutting structure, and it will lose the strength under very high temperatures. This can lead to cutter breakage, and the bit loses its performance. Without the thermal restriction from the studs, a TSP bit can withstand much higher temperatures [5].

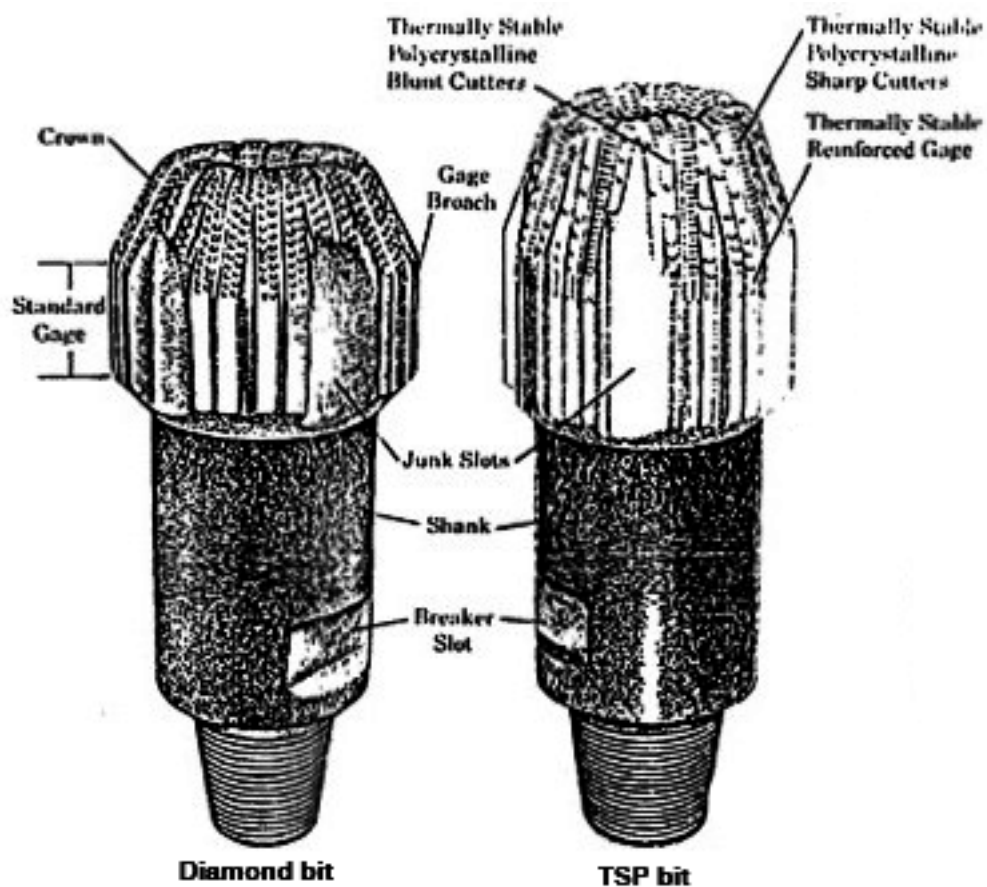


Figure 2.14  
Diamond and TSP bit terminology [24]

### 2.3.3 Applications of Diamond Bits

The following applications of diamond bits are taken from the drilling engineering learning course in Baker Hughes [4]:

Short roller cone bit life:	If roller cone bit life is very short due to mechanical failure, a diamond bit can increase the on-bottom time dramatically.
Low penetration rates with roller cone bits:	If the roller cone bit drills at very slow rates due to a stringer of hard formation, diamond bits can provide time and cost savings.
Small holes:	Small diameter roller cone bits have limited life due to space limitations on the bearing and cone shell thickness. The solid piece of a diamond bit will last much longer in very small boreholes.
Directional drilling:	Some diamond bits are designed for sidetracking and more proper to use for directional drilling.
Limited bit weight:	Diamond bits drill at higher ROP with less weight than roller cone bits in the same size range.
Downhole motor applications:	Roller cone bits usually have bearing failures on motor applications due to high rotary speeds. Under these conditions, diamond bits will have longer bit life.
Cutting casing windows:	Cutting through casing using diamond bits are now an effective and proven method for re-entering older wells.
Coring:	The use of diamond bits for coring operations gives smooth, whole cores.

Drilling situations where diamond bits should be avoided:

Very hard broken formations:	Broken formations can cause severe shock loading on diamond bits resulting in diamond breakage.
Formations containing chert or pyrite:	Chert and pyrite usually break apart in large pieces and may damage the diamonds.

### 2.3.4 Diamond Bit Specification

The following example of diamond bit specification is taken from Baker Hughes’ internal webpage:



**Reference Photo:** 8-1/2 in. ( 215.9mm) S280G8

Product Specifications	
IADC:	M841
Fixed TFA	1.25 in <sup>2</sup> (806.2 mm <sup>2</sup> )
Number of Blades:	20
Gauge Length	6 in (152.3 mm)
Junk Slot Area	3.8 in <sup>2</sup> (24.5 cm <sup>2</sup> )
Bit Breaker:	010500081,123202139
Connection:	4-1/2 API REG
Makeup Torque:	
5 1/2" Bit Sub	12.5 - 13.7 kft-lb (17.0 - 18.6 kNm)
5 3/4" Bit Sub	16.5 - 18.0 kft-lb (22.4 - 24.4 kNm)
6"+ Bit Sub	17.6 - 19.5 kft-lb (23.9 - 26.4 kNm)
Reference Part Number:	C0133
Status:	R

#### Operating Recommendations\*:

<b>Hydraulic Flow Rate:</b>	265 - 665 gpm (1000 – 2500 lpm)
<b>Rotation Speed:</b>	For Turbine and High Speed Motor Applications
<b>Max. Weight On Bit:</b>	37 klb (17 tn or kdaN)

**Figure 2.15**  
8 ½-in S280G8 Diamond bit specification  
(Source: Baker Hughes Tools)

**Classification:**

This is a diamond bit with matrix body and short taper medium cone profile. The hydraulic system is ribbed with changeable jets. Cutter size is large with light density.

**Gauge:**

Gauge length is 6-in.

**Rotary speed:**

The bit is suitable for high-speed turbine and positive displacement mud motors.

**WOB requirement:**

Maximum weight on bit allowed is 17 tn.

## 2.4 Roller Cone Bits

The roller cone consists of three main parts:

1. Cones
2. Bearings
3. Body

Each cone is made of two to three concentric rows of steel or tungsten carbide insert teeth. The teeth mesh with adjacent cones and are mounted on the bit journal. Tungsten carbide is a chemical compound containing equal parts of tungsten and carbon atoms. It is known for being a hard metal that can withstand very high temperature. Bits that are designed with TCI are more durable and maintain high efficiency in rock destructions. The main difference between TCI and steel tooth bits is that the teeth in TCI bits are pressed into the cones and not milled into them [5].

The size of the components in the bit depends on the formation hardness. Bits for soft formations require smaller weight, smaller bearings, smaller cone shell thickness and thinner legs. That gives more room for long, thin cutters. Drilling in hard formations requires more weight, bigger bearings, steadier body and stubbier cutters.

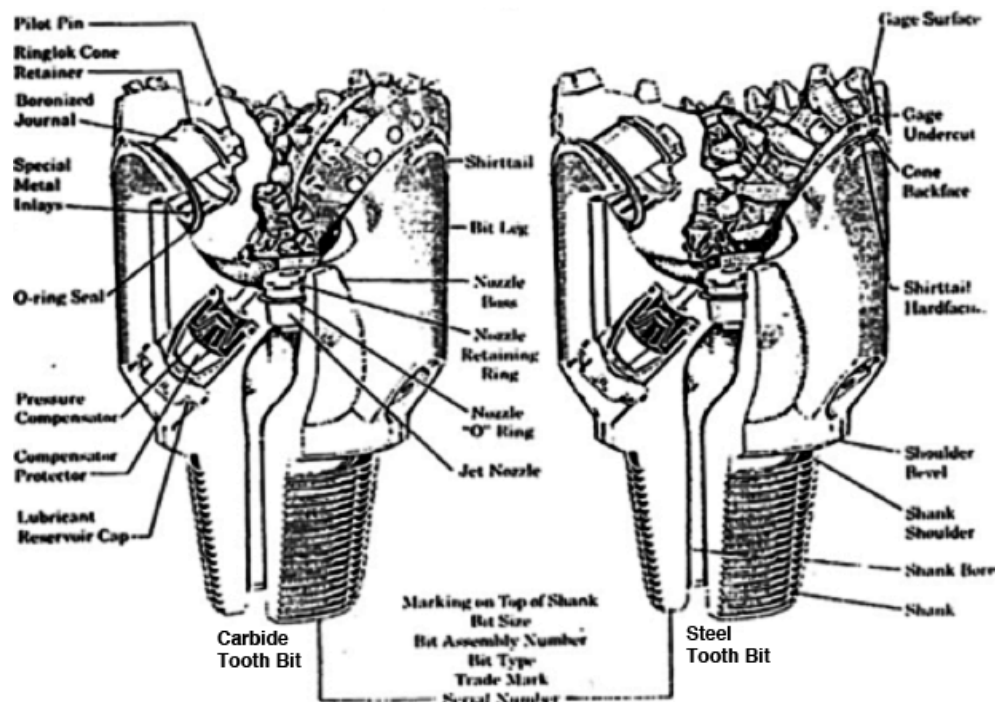
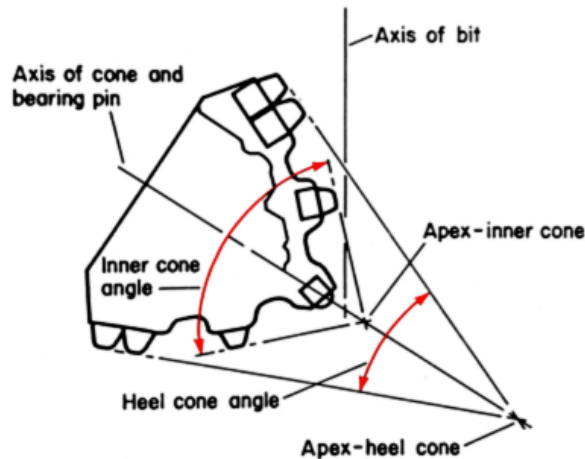
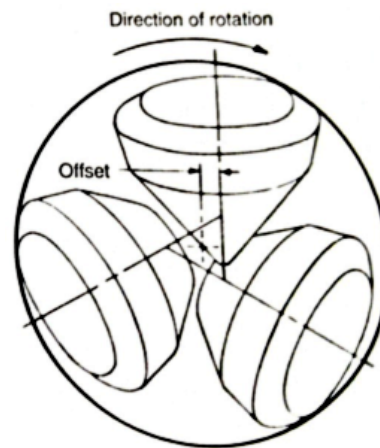


Figure 2.16  
Rock bit terminology [24]

Cone angles affect the way the teeth crush the rock. The cone has two angles, and neither of them has its apex in the center of the bit (**Figure 2.17**). Higher angles will give higher teeth exposure and be more aggressive on the formation. The cones rotate around the axis of the bit at the same time as they rotate around their own axis and subsequently lead to skidding (**Figure 2.18**). By offsetting the axis of the cones in relation to the axis of rotation enhances this effect and increases ROP. In harder formations, the cones move closer to real rotation with little offset and break down the rocks by crushing it [24].



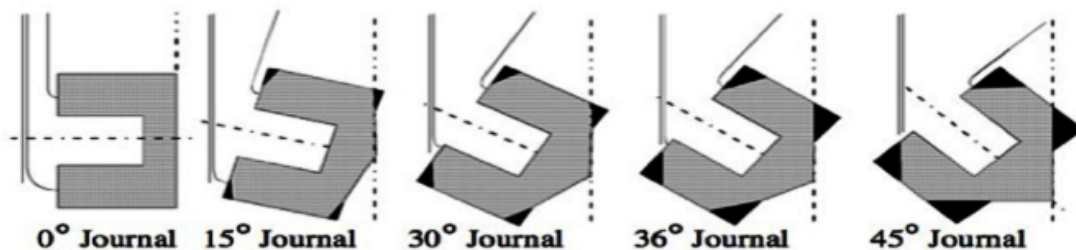
**Figure 2.17**  
Cone for soft formation [24]



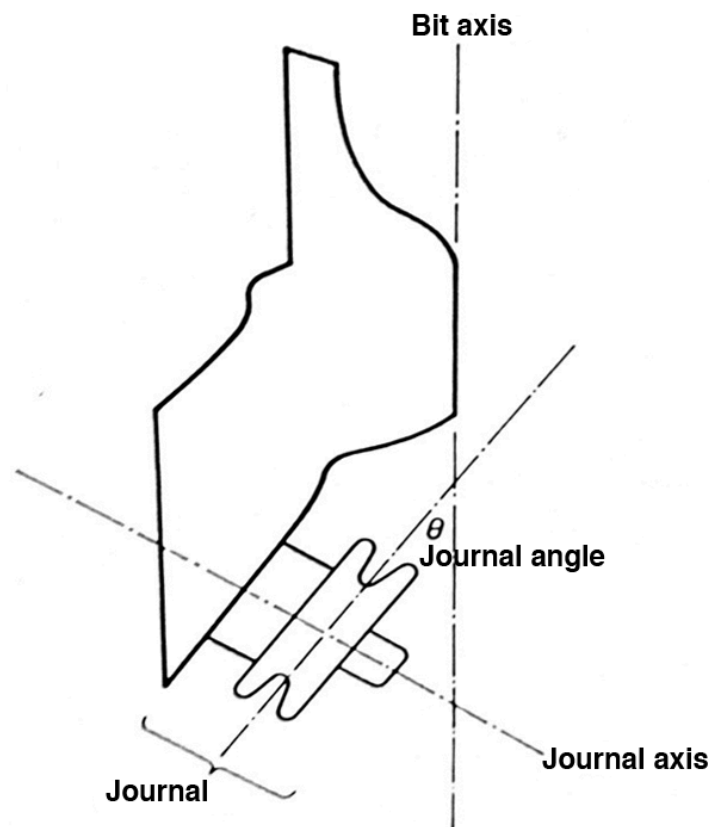
**Figure 2.18**  
Skidding [24]

### 2.4.1 Journal Angle

The journal (**Figure 2.20**) is the metal shaft where the cones are mounted and manufactured for the insertion of bearings, which allow the cones to rotate. The angle between the axis of the bit and the journal is called journal angle and is one of the basic design fundamentals of the roller cone bit. All cones on the same bit always have the same angles. This angle controls the extent of cutter action on the bottom of the hole and varies in each type of formations. In soft formations, the journal angle is  $33^\circ$  and emphasizes cutter action with greater tooth penetration. To reduce cutter action in medium formations the angle is increased to  $34-36^\circ$ . In hard formations, the angle is as large as  $39^\circ$  to minimize cutter action and teeth breakage [4].



**Figure 2.19**  
Journal angles in roller cone bits [27]

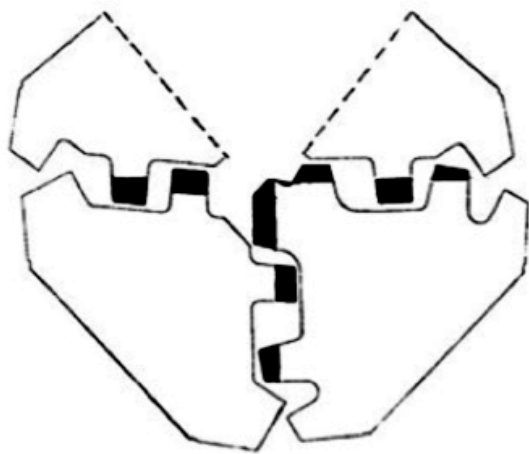


**Figure 2.20**  
Bit journal [24]

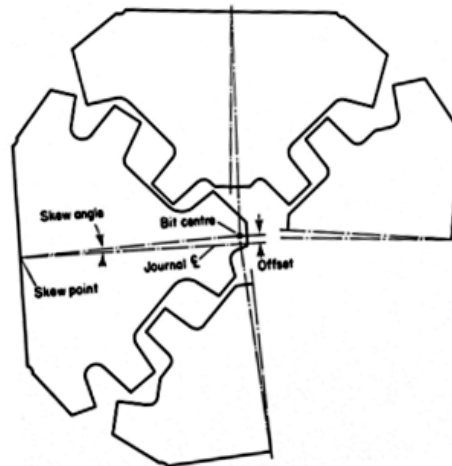
### 2.4.2 Interfitting and Cone Offset

The intention of interfitting (**Figure 2.21**) or meshing teeth is to allow the inner row of teeth to crush new rock on each rotation and also to allow larger bit parts in the design. This means that all three cones in the same bit must be different. As shown in **Figure 2.23**, the offset is a measure of how much the cones are moved so that their axes do not intersect at the same point in the center of the hole. High offset may cause the cone to stop rotating in periods as the bit scrapes the formation much like the drag bit. Small offset tends to increase cutter action, but will also result in larger tooth wear. The skew angle or offset angle is often expressed as the angle between the cone centerline and the horizontal axis of the bit as shown in **Figure 2.22**. The angle may be from  $4^\circ$  in soft formations, to  $0^\circ$  in harder formations [7].

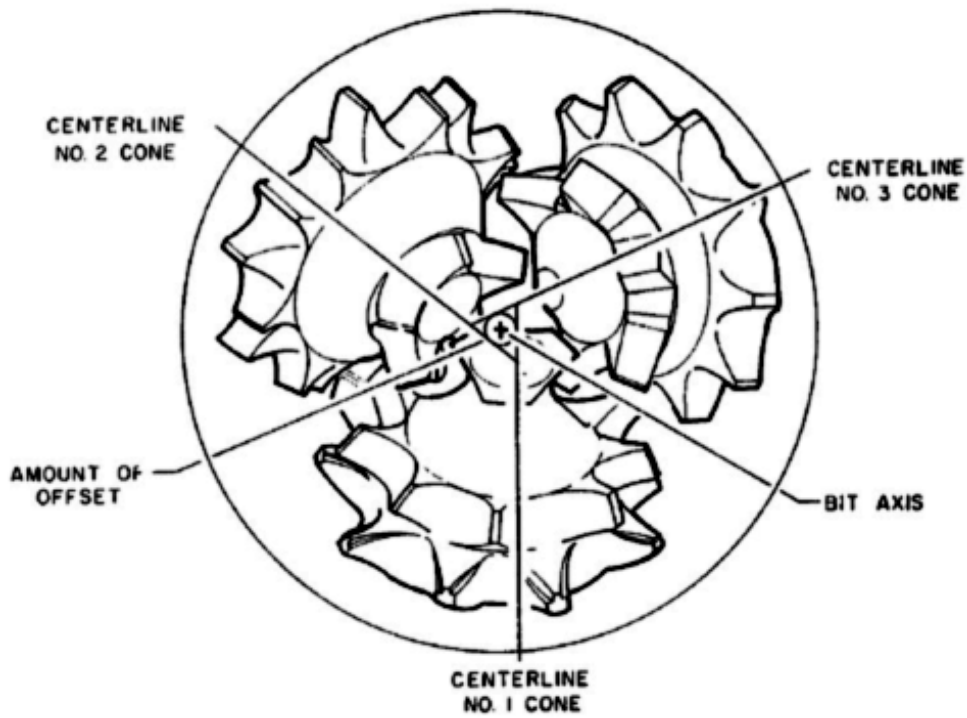




**Figure 2.21**  
Interfitting teeth [4]



**Figure 2.22**  
Skew angle [4]



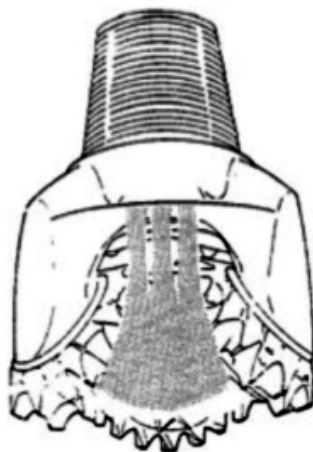
**Figure 2.23**  
Cone offset [4]

### 2.4.3 Hydraulics

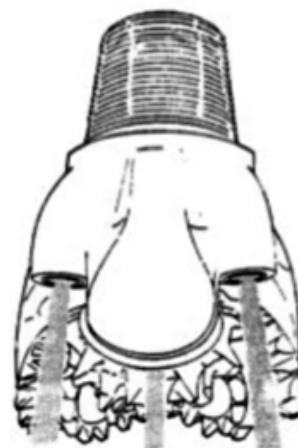
Early type of roller cone bits had a regular circulation system with one to three holes in the center of the bit and the fluid washed the bit from the center (**Figure 2.24**). This circulation system was not effective since the fluid did not distribute the fluid equally from the inner row to the outer row of teeth. A more adequate rock bit with jet nozzles was introduced in 1942 (**Figure 2.25**). The jet nozzle was a major improvement in bit hydraulics. It is now used as standard system for all roller cone bits. The main purpose of the high-velocity jet of fluid is to keep the bit teeth and bottom of the hole clean. The fluid also helps cooling down the bearings while flushing the drilled cuttings towards annulus. The jet bit has three nozzles located on each of the arms of adjacent cones and nozzle sizes may vary for more effectiveness depending on hydraulic action requirements [4,24]. An additional jet may be placed in the center of the bit. This is to prevent bit balling and the related reduction in ROP. The hydraulic system can be unbiased or biased in special applications. An unbiased configuration means that the nozzle directs the fluid between cones toward the corner of the borehole wall. Biased configuration is when the nozzles are positioned so that the fluid cleans the heel and adjacent heel teeth. Compressed air or gas is a third type of circulation, which can be used with either jet nozzle or regular circulation bits [4].

There are three types of jet nozzles [24]:

1. Shrouded nozzle jets: Provides maximum protection against retainer ring erosion or excessive turbulence.
2. Standard jet nozzles: Used in situations where erosion is not a problem.
3. Air jet nozzles: Used in bits designed for drilling with air or gas.



**Figure 2.24**  
Regular circulation [4]



**Figure 2.25**  
Jet nozzle circulation [4]



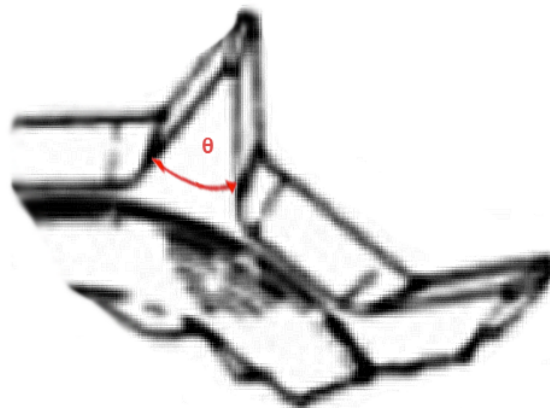
## 2.4.4 Cutting Structures

When the roller cone bits were introduced into the oilfield, the cutting structures were made of steel and delivered good performances in medium to hard formations. However, the bits struggled when hitting stringer of harder formations. Changes in tooth height, numbers of teeth per cone and thickness were applied as a solution, but did not perform as expected. In 1949, Hughes Tool Company introduced the TCI bit with a different cutting structure since the harder formations tended to grind off the steel teeth. The new TCI bit was more durable and on bottom drilling hours increased extensively [4]. Tungsten carbide inserts are explained in section 2.4.

Roller cone bits are separated according to what formation types they intend to drill. This include variations in tooth cutting structure, tooth spacing, tooth hardfacing and tooth angle (**Figure 2.26** and **2.27**).



**Figure 2.26**  
Tooth spacing [4]



**Figure 2.27**  
Tooth angle [4]

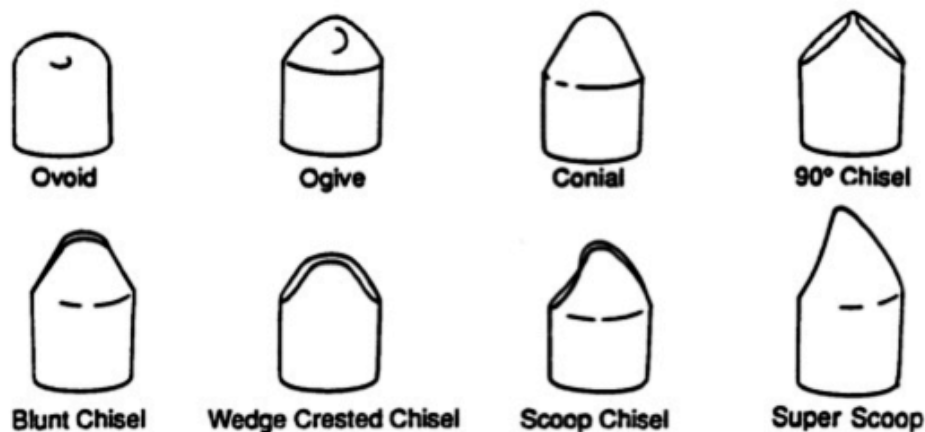
Steel teeth bits are used when spudding a well, drilling in soft formations, drilling at high ROP or in zones where bed thickness makes insert bits ineffective. Teeth made for drilling in soft formations is long and scattered, to cut deeper in the formation and tear off large cuttings. Teeth in medium formations are more closely spaced and have larger angles to withstand higher load from the rocks.

Hard formations have high rock strengths and require stronger teeth for effective crushing. The teeth must be short and very close spaced with thick cone shells to withstand the high loads.

Tooth angles in various formations can be [4]:

Formations	Degrees
Soft	39° – 42°
Medium	43° – 46°
Hard	47° – 50°

TCI cutting structures may vary in shapes depending on drilling applications (**Figure 2.28**). The chisel shaped teeth were very effective in the early days with good drill rates because of light bit weights causing the sharp teeth edges to shear and crush the rocks simultaneously. The effective chisel shape was later eliminated due to the introduction of heavier drill bits in newer drilling practices. The heavy bits were manufactured with conical or blunt shaped teeth, and they have proven to be the most efficient teeth shapes in all formations [4].



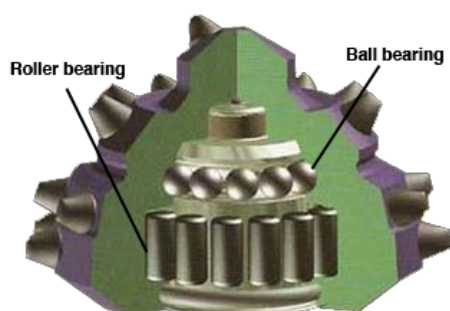
**Figure 2.28**  
Tungsten carbide tooth shapes [4]

## 2.4.5 Bearing Systems

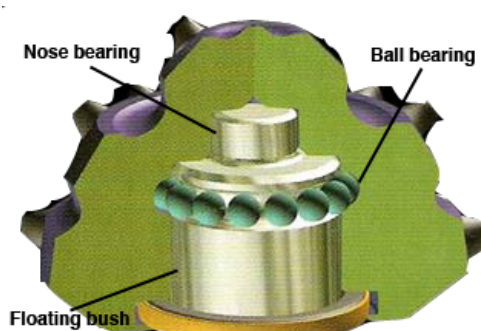
The roller cone bits have three bearing designs located in each cone. In the heel is roller bearing, which carries most of the load and receives most of the wear. Roller bearings can resist large axial forces also being able to sustain large radial forces. The ball bearing in the middle holds the cone on the journal, and the purpose is to reduce rotational friction. The last bearing is a hardened bushing at the nose of the cone for resisting seizure and wear.

There are currently four types of bearing systems for roller cone bits [6]:

1. Open roller bearing: This is a standard bearing without seal, meaning that the bearing is open to outside debris. The advantage of this bearing is that they are cheap and ideal for drilling shallow holes. In this system, the cones will spin freely with a front row of ball bearings and a back row of roller bearings.
2. Sealed roller bearing: Have the same features as the open roller bearing, but are sealed with an O-ring seal. The seal acts as a barrier against mud and cuttings.
3. Journal / Friction bearing: Has a floating bushing that is highly resistant to heat and surface damage instead of the rollers.
4. Air blast bearing: Have much of the same features as open roller bearing, but has air injection directly to the cones. This type of bearing is used in air circulation bits. These bits have special passageways to supply air to the bearings for cooling and lubricating.



**Figure 2.29**  
Open roller bearing [6]



**Figure 2.30**  
Journal / Friction bearing [6]

## 2.4.6 IADC Roller Cone Classification

The International Association of Drilling Contractors adopted the first three-digit bit code in 1972. The system was very successful because it conveys considerable information in a simple form. Innovations excelled with new bit designs and the IADC determined to add the new features in a fourth digit. The new code was approved in 1987 and is still a standard classification system for roller bits. The four-digit code is distinguished from the PDC code by putting the alphabetic digit at the end and the three numerical numbers at start [34].

The code is described like this:



1. The first code defines the teeth series of the bit regarding to what type of formation the bit will drill. The numbers 1-3 means that the bit has steel teeth, and 4-8 means that the bit has TCI. Smaller numbers in each series indicate longer and more widely spaced teeth for drilling in soft formations while higher numbers indicate closer spaced and shorter teeth for harder formations.

Steel teeth		TCI	
1	Soft formation	4	Soft formation
2	Medium formation	5	Soft medium formation
3	Hard formation	6	Medium formation
		7	Hard formation
		8	Extra hard formation

2. The second code is divided in four types of formation hardness relative to the teeth series. Type 1 refers to the softest formation in a particular series and type 4 refers to the hardest formation.

3. Seven categories of bearing and gauge systems are defined in the third code. The alternatives are:

1	Standard roller bearing
2	Roller bearing – air cooled
3	Roller bearing – gauge protected
4	Sealed roller bearing
5	Sealed roller bearing – gauge protected
6	Sealed friction bearing
7	Sealed friction bearing – gauge protected

4. The fourth letter is optional and sometimes added at the end of the code if the bit has additional features:

A	Bits with friction-sealed bearings suited for air drilling
C	Jet bits with a central nozzle
D	Special bits for deviated wells
E	Jet bits with elongated nozzles
G	Bits with reinforced protected gauge
J	Bits with jet deflection
R	Bits with reinforced welds for cable-tool drilling
S	Bits with standard steel teeth
X	Bits with chisel inserts
Y	Bits with conical inserts
Z	Bits with other insert shape

Examples of roller cone bit codes:

BIT No.	IADC Code
A	515C

This is a TCI roller cone bit designed for soft-medium formations. The bit is intended to drill the softest formation of the particular series. Gauge protected sealed roller bearing is equipped, and the bit also has a central jet nozzle.

BIT No.	IADC Code
B	321

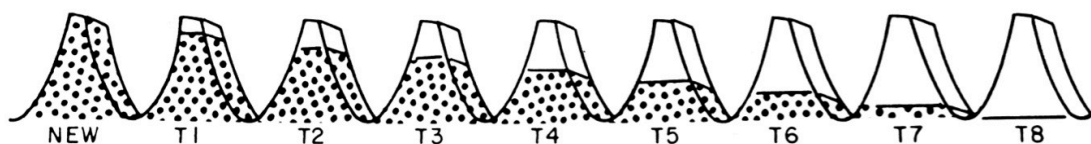
This is a steel tooth bit designed for hard formations. The bit can drill the second lowest formation hardness and has a standard roller bearing system. Additional features are not present.

## 2.4.7 IADC Roller Cone Dull Bit Grading

The IADC roller cone dull bit grading system was released contemporary with the introduction of PDC dull bit grading in 1987. This grading is almost identical with the fixed cutter grading but has different codes in some columns. However, a new version was developed with minor changes in 1992 and is presented in the table [19]:

CUTTING STRUCTURE							
Inner Rows	Outer Rows	Dull Char.	Location	Bearing / Seals	Gauge	Other Dull Char.	Reason Pulled
1	2	3	4	5	6	7	8

Tooth wear is reported with a code from 1 to 8 (**Figure 2.31**). For example, if half of the original tooth height has been worn or lost, the bit will be graded with the code T4. It means that 4/8 of the tooth is missing. The teeth will in often not wear equally and grading the bit with one single code may be difficult [7]. In these situations, the average sum of tooth wear will be the right code.



**Figure 2.31**  
Tooth wear chart [7]

### Column 1

The tooth wear applies for all inner rows of the bit.

### Column 2

The tooth wear applies for gauge rows only.

**Column 3**

A two-letter code describes the dull characteristics of cutting structure:

BC	Broken cone*	LT	Lost teeth
BT	Broken teeth	NT	Not rerunnable
BU	Balled up	OC	Off center wear
CC	Cracked cone*	PB	Pinched bit
CD	Cone dragged*	PN	Plugged nozzle or flow passage
CI	Cone interference	RG	Rounded gauge
CR	Cored	RO	Ring out
CT	Chipped teeth	RR	Rerunnable
ER	Erosion	SD	Shirttail damage
FC	Flat crested wear	SS	Self sharpening wear
HC	Heat checking	TR	Cone Tracking
JD	Junk damage	WO	Washed out bit
LC	Lost cone*	WT	Worn teeth or cutters
LN	Lost nozzle	NO	No dull characteristics
		*	<i>Show location in column 4</i>

**Column 4**

Location of dull characteristics described:

N	Nose row
M	Middle row
G	Gauge row
A	All rows
1	Cone #1
2	Cone #2
3	Cone #3

**Column 5**

This column indicates bearing condition of roller cone bits. For nonsealed bearings, a linear scale from 0-8 is used to describe the amount of bearing life that has been used. For sealed bearing, a letter code is used to indicate the condition.

	Non-sealed bearings	Sealed bearings	
No life used	1	E	Seals effective
	2	F	Seals failed
	3	N	Not able to grade
	4		
	5		
	6		
	7		
All life used	8		

**Column 6**

This column describes the gauge wear of the bit:

- I In gauge
- 1 1/16"
- 2 2/16"
- 3 3/16"
- 4 4/16"
- 5 5/16"
- etc.

**Column 7**

This column is used to report any additional dull characteristics of the bit and refers to column 3 codes.

**Column 8**

Reason for terminating the bit run:

- |     |                             |    |                     |
|-----|-----------------------------|----|---------------------|
| BHA | Change bottom hole assembly | PR | Penetration rate    |
| DMF | Downhole motor failure      | TD | Total depth         |
| DSF | Drill string failure        | TQ | Torque              |
| DST | Drill stem test             | TW | Twist-off           |
| DTF | Downhole tool failure       | WC | Weather conditions  |
| LOG | Run logs                    | WO | Washout drillstring |
| LIH | Left in hole                |    |                     |
| RIG | Rig repair                  |    |                     |
| CM  | Condition mud               |    |                     |
| CP  | Core point                  |    |                     |
| DP  | Drill plug                  |    |                     |
| FM  | Formation change            |    |                     |
| HP  | Hole problems               |    |                     |
| HR  | Hours on bit                |    |                     |
| PP  | Pump pressure               |    |                     |

Examples of roller cone bit grading:

IADC GRADING							
17 ½" MXL-ST303DX Roller Cone Bit							
I	O	D	L	B	G	O	R
1	1	WT	A	E	1	NO	BHA

The grading indicates that the bit had slightly worn teeth both at inner rows and gauge rows. The dull characteristics were mainly worn teeth in all rows. This bit had sealed bearings and all were effective. The gauge was worn 1/16-in, and no other dull characteristics were observed. The bit was pulled due to change of BHA.



IADC GRADING							
17 1/2" MXL-T309DX Roller Cone Bit							
I	O	D	L	B	G	O	R
1	1	BT	A	E	I	NO	TD

The grading of this bit indicated some worn cutters both at inner rows and gauge rows. Worn cutters were identified as broken teeth at all rows of the bit. The sealed bearings were effective. The gauge was “in gauge” and no other dull characteristics were observed. The bit run was terminated due to casing point.

### 2.4.8 Rock Cutting Mechanics

The rock cutting mechanism of the rolling cutter bits is intrusion. This means that the teeth are forced into the rock by the WOB, and the rotary action. The following rock cutting principle is taken from Bourgoyne, Millheim and Chenevert (1986, p. 208-209):

- (A) Load is applied to a bit tooth.
- (B) Constant pressure beneath the tooth increases until it crushes the rock. Then a wedge is formed.
- (C) As the force on the tooth increases, the material in the wedge compresses and exerts high lateral forces on the rock. The rock fractures when the shear stress exceeds the shear strength of the rock.
- (D) As the rock fractures, subsequent fracturing occurs in the region above the initial fracture, forming a zone of broken rock.

Low differential pressure:

- (E) At low differential pressure, the cuttings formed in the zone of broken rock are ejected easily from the crater.
- (F, G) The bit tooth then moves forward until it reaches the bottom of the crater and then the process may be repeated.

High differential pressure:

- (E') At high differential pressure, the downward pressure and frictional forces between the rock fragments prevent ejection of the fragments.
- (F', G') As the force on the tooth is increased displacement takes place along fracture planes and form “pseudoplastic craters” (appearance of plastic deformation).

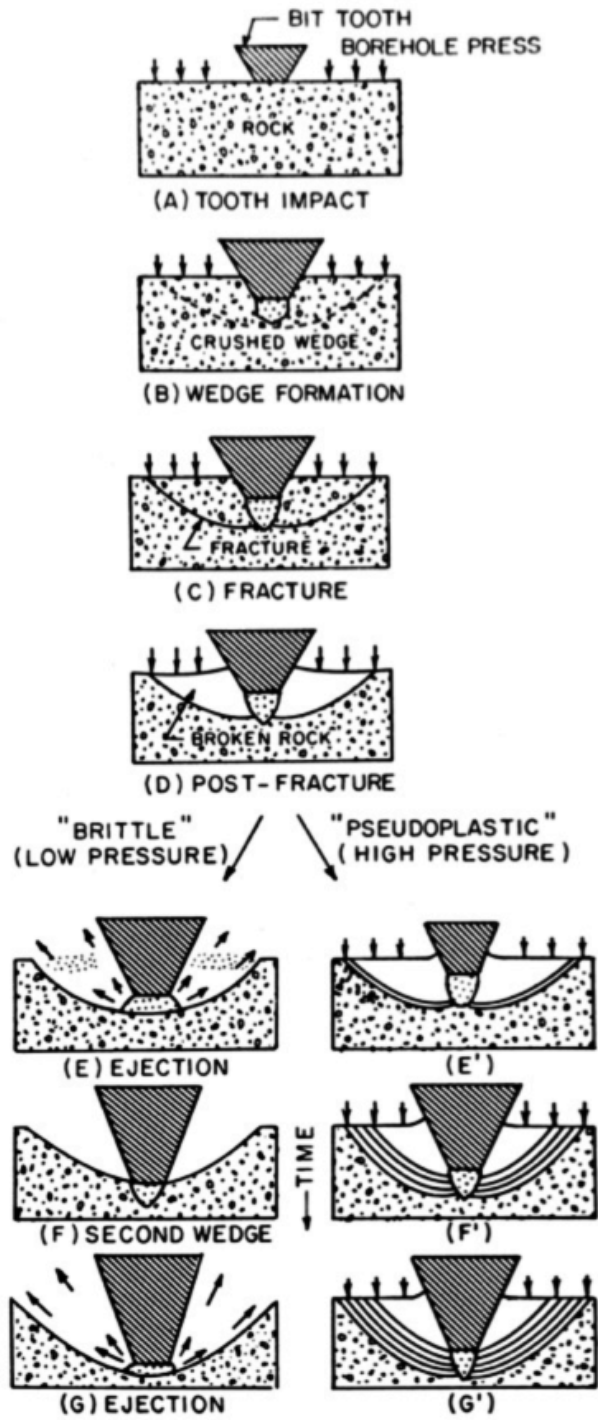


Fig 2.32  
Crater mechanism beneath a bit tooth [7]

## 2.4.9 Roller Cone Bit Specifications

The following examples of roller cone bit specification is taken from Baker Hughes' internal webpage:



Product Specifications	
IADC:	116
Bearing / Seal Package:	Journal / O-ring
Cutting Structure:	
Inner Row	Inverted Radius
Heel Row	Bi-Metallic
Gauge Row	Macro
Gauge Trimmers	Pad
Tooth Hardfacing:	Endura
OD Hardfacing:	Shirttail
Nozzle Type:	N/A
Center Jet Display:	N/A
Makeup Torque:	12.0 - 16.0 klbf-ft (16.3 - 21.7 kNm)
Connection:	4-1/2 REG API
Approx. Shipping Weight:	90 lb ( 40.8 kg)
Reference Assembly Number:	584463000

### Operating Recommendations\*:

Weight On Bit:	17.5 - 42.5 klb (7 - 19 tn or kdaN)
Rotation Speed:	For Rotary and Motor Applications

**Reference Photo:** 8-1/2 in. ( 215.9mm)  
GT-1

**Figure 2.33**  
8 1/2-in EP4630 Steel tooth bit specification  
(Source: Baker Hughes Tools)

### Classification:

This particular bit is manufactured with milled tooth and designed for drilling in soft formations. The teeth are the second softest type in the series. Bearing system include sealed friction bearing.

### WOB requirement:

This bit can operate within 7 – 19 tn.



**Reference Photo:** 8-1/2 in. ( 215.9mm)  
GT-20

Product Specifications	
IADC:	517
Bearing / Seal Package:	Journal / O-ring
Cutting Structure:	
Inner Row	Dbl Angle Chisel
Heel Row	Dbl Angle Chisel
Gauge Trimmers	PDC Chisel
Gauge Row	Gage
OD Hardfacing:	Shirttail
Nozzle Type:	Standard
Center Jet Display:	N/A
Makeup Torque:	12.0 - 16.0 klbf-ft (16.3 - 21.7 kNm)
Connection:	4-1/2 REG API
Approx. Shipping Weight:	94 lb ( 42.6 kg)
Reference Assembly Number:	A8420D58

**Operating Recommendations\*:**

Weight On Bit:	22.5 - 52.5 klb (10 - 23 tn or kdaN)
Rotation Speed:	For Rotary and Motor Applications

**Figure 2.34**  
8 1/2-in GT-20DT TCI bit specification  
(Source: Baker Hughes Tools)

**Classification:**

The following bit is manufactured with TCI and designed for soft medium formations. Bearing and gauge system includes sealed friction bearing and gauge protection.

**WOB requirement:**

The bit performance is best within 10 – 23 tn.

## 3 Selecting Drill Bits

Choosing the best type of bit for the formation that is being drilled is not a simple task since there is so many various series of bits available. The formation is hardly homogeneous in most cases and may vary in hardness. Any selected bit will meet lithological challenges regardless of bit series. In what follows, are important parameters to comprise when choosing a proper bit for drilling a well.

### 3.1 Cost Price Per Meter

Bit cost is a relevant factor when planning a new well. A comparison of several bits in terms of economic life is often done to find the most cost effective bits for the actual drilling application. Data from previous wells with similar lithology is used in the estimations. How is the economic life of drill bits measured? By calculating the total amount of money spent to drill the distance with that bit. This includes tripping and drilling time in consideration to rig rental hours. Time starts when the new bit has been attached onto the BHA and includes hours taken to run in hole, drill the distance and pull out.

The following parameters are essential in the calculations:

- $P_b$  Net cost of the bit
- $P_r$  Rig rental price per hour
- $T_t$  Tripping time
- $T_r$  Drilling time
- $m$  Number of meters drilled

Cost price per meter is given by the equation [24]:

$$P_m = \frac{P_b + P_r(T_r + T_t)}{m}$$

Examples of cost per meter calculations:

- Case 1) Bit A is an 8 ½-in PDC type with an advanced cutter technology that can drill fast with high agressivity. The net cost of this bit is \$60000 and it drilled a distance of 1400m with average ROP of 40 m/hr. Total trip time for RIH and POOH was 12 hours.

Case 2) Bit B is an 8 ½-in PDC type with a standard cutter technology. This bit drills a little bit slower than the previous type but are more durable. The net cost of this bit is \$40000 and it drilled a distance of 2000m with average ROP of 30 m/hr. Total trip time for RIH and POOH was 16 hours.

Rig rental price per hour is approximately \$62500 for a semisubmersible rig in a high cost area like the North Sea.

Cost Per Meter:

Case 1)

$$\text{Drilling time: } \frac{1600m}{40m/hr} = 40hr$$
$$P_m = \frac{60000 + 62500(12 + 40)}{1400} = \$2364/m$$

Case 2)

$$\text{Drilling time: } \frac{2000m}{30m/hr} = 67hr$$
$$P_m = \frac{40000 + 62500(16 + 67)}{2000} = \$2614/m$$

It can be seen from the calculations that Bit A is more cost effective than Bit B in despite of much higher bit cost and shorter distance drilled. However, if Bit B could drill with the same ROP as Bit A, then this would be more preferable.

Sometimes the bit run is terminated before the bit reaches the end of its operating life due to casing point, tool failure, reaming etc. There may be many other reasons for why the bit was pulled out of the hole. In such cases, the tripping time should seldom be regarded as bit tripping time.

### 3.2 Weight On Bit and Rate Of Penetration

Studies have shown that if the WOB is increased at constant rotational speed, there is an improvement in ROP. It is readily apparent that there is a direct relationship between bit weight and penetration rate. If the hydraulics can manage to keep the bit clean when drilling, increase of ROP is almost proportional to the WOB. The ROP can reach a maximum when the bit reaches the load limit. Higher load than this may damage the bit since the cone will support the extra weight. If too much WOB is applied, there is a risk for the following to happen [24]:

- Pipe buckling
- Destabilizing soft formations
- Doglegs where formation has high-angle dips
- Block the bit nozzles
- Damage the bit
- Logging tool failure

Weight on bit can also be limited by the bit design. Bits for drilling in soft rocks have long and scattered teeth. This leads to a confined space for larger bearings, thus lower weight resistance. Small-toothed bits for hard formations have more room for larger bearings and can withstand higher loads. The roller cone bit specifications from section 2.3.9 indicates a WOB requirement of 7 to 19 tn for the milled tooth and 10 to 23 tn for the TCI, which verify the previous statements. WOB in drilling applications, in the North Sea, can change rapidly between 1 to 20 tn. This may depend on the bit type and drilling assembly.

As mentioned, the WOB is related to the ROP and both cannot be increased at the same time without causing adversely stress conditions in the drill string and the bit. The rotational speed may be limited by following conditions [24]:

- Vibrations in the drill string, which can cause fatigue and failure
- Drag in deviated wells
- Stringer of hard formations
- Bit failures
- Ineffective hole cleaning
- Excessive mud weight



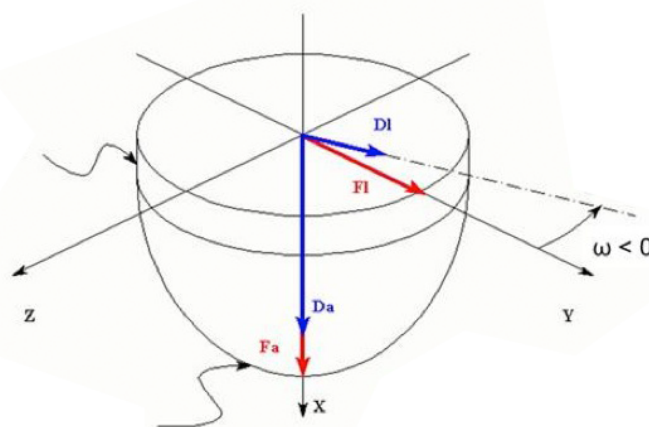
### 3.3 Drillability

The directional capability of a drill bit is influenced by steerability and walking tendency. Walking tendency is the tendency of the bit to deflect during drilling, which causes the hole to be misplaced. The angle between the lateral force (F<sub>l</sub>) and the lateral displacement (D<sub>l</sub>) of the bit is called the walk angle  $\omega$  (**Figure 3.1**). If the walk angle is higher than zero, then the bit has a “right” tendency. Conversely, the bit has a “left” tendency when the angle is smaller than zero. If the angle is precisely zero or in the same direction as the lateral force, then the bit has a “neutral” tendency [20].

Steerability is described as the ability of the bit to perform a lateral displacement when generating a side force. The bit steerability (BS) can be defined as the ratio of lateral drillability (LD) over axial drillability (AD), whereas drillability is the relation of displacement per revolution over side force or WOB [20]:

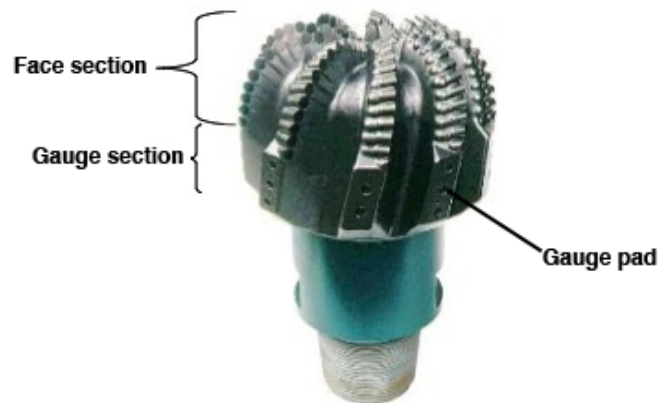
$$BS = \frac{LD}{AD} \quad , \quad Drillability = \frac{Displacement}{Force}$$

Bit characteristics may affect the steerability in many ways. An aggressive cutting structure could jeopardize the bit’s ability to steer. Roller cone bits are easier to steer because they are less aggressive than PDC bits. However, PDC bit technology has continuously improved to increase steerability. Gauge (**Figure 3.2**) configurations directly influence the stability and steerability of a bit. An effective side-cutting profile will penetrate the adjacent rocks in a satisfied way when directional alteration is needed. The length of the passive gauge (**Figure 3.4**) has the greatest role in this case. Given a side force and bit tilt (**Figure 3.3**), applied by directional system the shorter the passive gauge is, higher is the steerability. It is important to emphasize the fact that bit tilt plays an important role as the bit points in the tilted direction and tends to drill in that direction [21]. Long gauges will give good directional stability but are they harder to steer with RSS. Inversely, short gauge sections will change direction more easily but entails poorer hole quality. Which designs are the best depends on the drilling application.

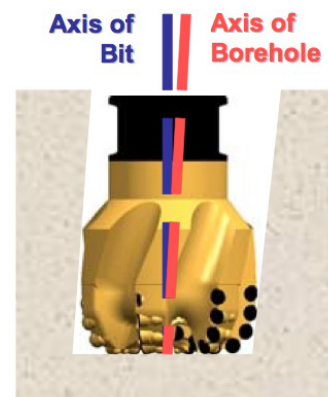


**Figure 3.1**  
Bit steerability and walk angle [20]

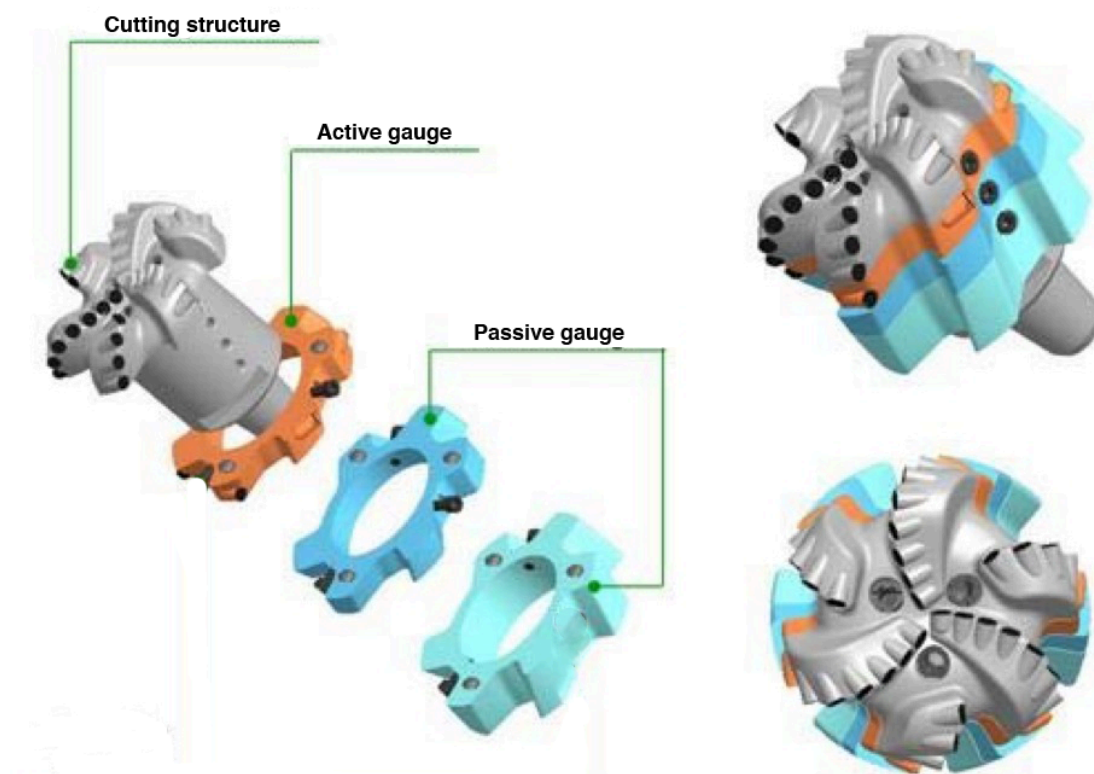




**Figure 3.2**  
Bit gauge [21]



**Figure 3.3**  
Bit tilt [15]



**Figure 3.4**  
Active and passive gauge [20]

### 3.4 PDC versus Roller Cone

Conventional bits can often be used in the same drilling applications. The following tables show a comparison between PDC and roller cone bits that might come in handy when decision between the two types must be assessed:

Roller cone	
Characteristics	Disadvantages
<ul style="list-style-type: none"> <li>• Steel tooth: Used in top hole where the formation is soft</li> <li>• TCI: Used in medium to very hard formations or where PDC does not work</li> <li>• Slow to medium ROP</li> <li>• Good steerability</li> <li>• Cheaper than PDC</li> <li>• Low torque</li> </ul>	<ul style="list-style-type: none"> <li>• Cones can be lost resulting in fishing operations</li> <li>• Prematurely worn teeth</li> <li>• Bearing is a weak point</li> <li>• Gauge wear</li> <li>• Bit balling</li> <li>• Axial vibration (bit bounce)</li> <li>• Lateral vibration (whirl)</li> </ul>

PDC	
Characteristics	Disadvantages
<ul style="list-style-type: none"> <li>• Drills in soft to medium hard formations</li> <li>• Normally used in lower sections from 12 1/2" →</li> <li>• Used in steerable and rotary applications</li> <li>• High ROP</li> <li>• More robust drilling → fewer trips</li> <li>• High torque</li> </ul>	<ul style="list-style-type: none"> <li>• Prematurely worn cutters</li> <li>• 3-4 times higher torsional vibration than RC (stick slip)</li> <li>• Too aggressive cutters increase lateral vibrations and cause severe damage to bit and drillstring</li> <li>• Very unaggressive cutters result in poor depth of cut and makes the bit unstable and liable to whirl</li> <li>• More expensive than RC</li> <li>• Not applicable in very hard and abrasive formations</li> </ul>

## 4 Kymera

The hybrid bit has evolved technologically and visually since the first prototype (**Figure 4.1**) appeared on the drawing table. The Kymera design (**Figure 4.2**), since its introduction, has shown to be more than a viable competitor to conventional bits. Baker Hughes' Kymera team claims that [2]:

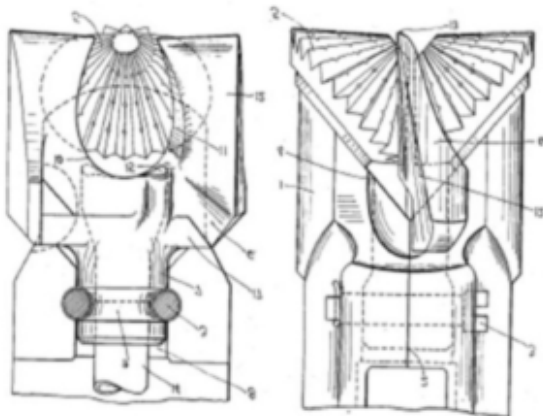
Compared to PDC bits, Kymera has:

- Lower and more consistent drilling torque
- Better dynamics and directional control
- Improved durability and reliability in interbedded formations
- Less torsional vibrations
- Higher overall ROP

Compared to traditional roller cone bits, it has:

- Increased ROP potential
- Less axial vibration
- Lower weight on bit requirement
- Higher footage drilled in less time (plastic formations)

Over 350 field test runs around the world have been conducted to verify the previous claims and are still an ongoing process. Baker Hughes' most-recent bit is an innovative and patented design with minimal technological specifications released to the public. So far the oil companies involved in the funding of the field tests demand data to remain confidential. However, three papers presented at the SPE drilling and offshore conferences from 2010 to 2011 have been released.



**Figure 4.1**  
Blueprint of the first hybrid prototype [26]



**Figure 4.2**  
12 1/4-in Kymera Hybrid Bit  
(Source: Baker Hughes Tools)

The new Kymera bit design is simply a combination of a roller cone and a PDC bit. It is based on four-bladed and six-bladed advanced cutter PDC technology (**Figure 4.3, 4.4 and 4.5**), which the secondary blades have been replaced with a TCI rolling cone. A small bit has two cones and two blades, while the larger type is manufactured with three cones and three blades. The intention is to take advantage of the best properties from the roller cone and the PDC bit. With the synergistic combination of the diamond shearing and roller cone crushing the formation, the bit can gain groundbreaking escapades. The Kymera is mainly designed for the following [2]:

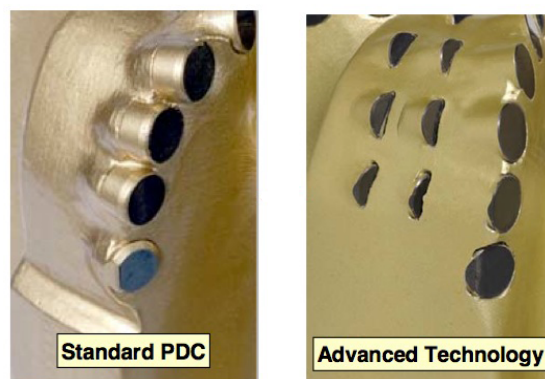
- Roller cone applications that are ROP limited.
- Large diameter applications that are torque and WOB limited.
- Highly interbedded formations where high torque fluctuations can cause premature failures.
- Motor and directional applications where higher ROP, build rates and tool face control are desired.



**Figure 4.3**  
Two-cone and two-bladed Kymera [26]



**Figure 4.4**  
Three-cone and three-bladed Kymera [26]



**Figure 4.5**  
Standard and advanced cutter technology [16]

The following specifications are taken from Baker Hughes’ internal webpage:



Reference Photo: 8-1/2 in. (215.9mm) HP522X

Product Specifications	
Number of Blades:	2
Primary Cutter Size	.625 in (15.8 mm)
Cutting Structure:	
Inner Row	CONIC
Heel Row	CONIC
Gauge Row	PDC
Bearing / Seal Package:	Journal / Metal
Number of Nozzles:	4
Nozzle Type:	Port, SP
Fixed TFA	.3 in <sup>2</sup> (193.5 mm <sup>2</sup> )
Gauge Length	5 in (127.0 mm)
Bit Breaker:	123224512
Connection:	4-1/2 API REG
Makeup Torque:	
5 1/2" Bit Sub	12.5 - 13.7 kft-lb (17.0 - 18.6 kNm)
5 3/4" Bit Sub	16.5 - 18.0 kft-lb (22.4 - 24.4 kNm)
6"+ Bit Sub	17.6 - 19.5 kft-lb (23.9 - 26.4 kNm)
Approx. Shipping Weight:	145 lb
Reference Part Number:	X16415
Status:	S

**Operating Recommendations\*:**

Hydraulic Flow Rate:	300 - 750 gpm (1150 - 2850 lpm)
Rotation Speed:	For Rotary and Motor Applications
Max. Weight On Bit:	Please see your Local BHI Representative for Recommendation

**Figure 4.6**  
8 ½-in HP522X Kymera specification  
(Source: Baker Hughes Tools)

The following bit is a small version of Kymera with two blades and two cones. It is designed for drilling in 8 ½-in sections. Two nozzles are placed on each side of the blades for effective hole cleaning. The local BHI representatives recommend maximum WOB at 15 tn for this size.





**Reference Photo:** 12-1/4 in. (311.2mm) HP533X

Product Specifications	
Number of Blades:	3
Primary Cutter Size	.625 in (15.8 mm)
Cutting Structure:	
Inner Row	CONIC
Heel Row	CONIC
Gauge Row	PDC
Bearing / Seal Package:	Journal / Metal
Number of Nozzles:	6
Nozzle Type:	Port, SP
Fixed TFA	.451 in <sup>2</sup> (290.8 mm <sup>2</sup> )
Gauge Length	5 in (127.0 mm)
Bit Breaker:	123210007,123215860,123210008
Connection:	6-5/8 API REG
Makeup Torque:	
7 1/2" + Bit Sub	37.1 - 42.4 kft-lb (50.3 - 57.5 kNm)
Approx. Shipping Weight:	289 lb
Reference Part Number:	X15535DB
Status:	S

**Operating Recommendations\*:**

Hydraulic Flow Rate:	550 - 1200 gpm (2100 - 4550 lpm)
Rotation Speed:	For Rotary and Motor Applications
Max. Weight On Bit:	Please see your Local BHI Representative for Recommendation

**Figure 4.7**  
12 1/4-in HP533X Kymera specification  
(Source: Baker Hughes Tools)

This is a larger version of Kymera designed for drilling in 12 1/4-in sections. A larger bit diameter gives more room for an additional blade and cone. The nozzle amount has also increased to six jet nozzles whereas two are placed on each side of the cones. Recommended WOB for this version is maximum 20 tn.

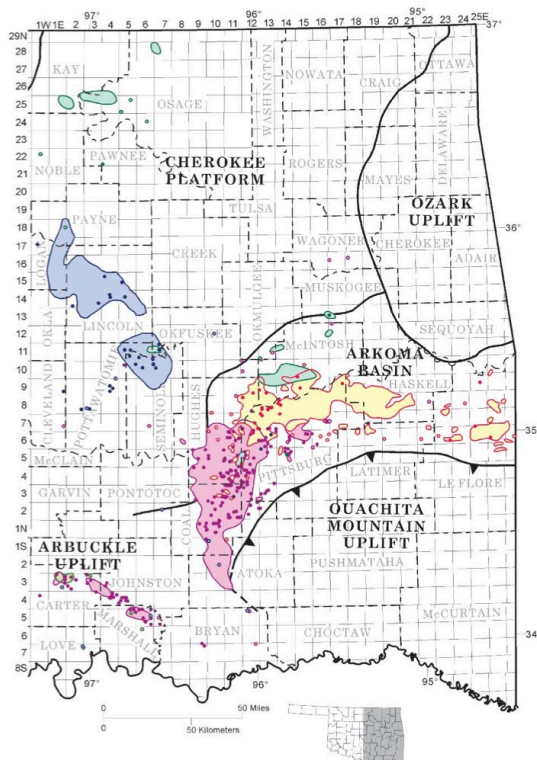
## 4.1 Field Testing

Baker Hughes has in collaboration with different oil companies conducted several field tests that have contributed to the development of the current hybrid design. Only a few field tests were carried out in the beginning with the early prototypes. Large-scale field-testing around the world was performed more recently because the new Kymera design showed more viability [13]. The following field tests briefly emphasize the notable drilling performances of Kymera compared to offset wells where conventional bits were utilized.

### 4.1.1 United States

The following information is taken from Dolezal et al (2010, p. 2-7):

The Deep Springer wells in Washita, Oklahoma, are typical deep vertical wells with TD up to 23 000 ft. It is known that the formation in this area is challenging to drill as it includes interbedded limestone, sandstone, claystone and chert with very high rock strengths. When drilling in a zone where the hardness varies between medium-hard and hard tends to jeopardize the durability of standard PDC bits. The 12 ¼-in sections are normally drilled 12500 ft through the hard and abrasive De Moines and Atoka formation. Previous wells consumed an abnormal high amount of roller cone and PDC bits in this troublesome section. High vibrations and torque fluctuations with severe bit dull were also common.

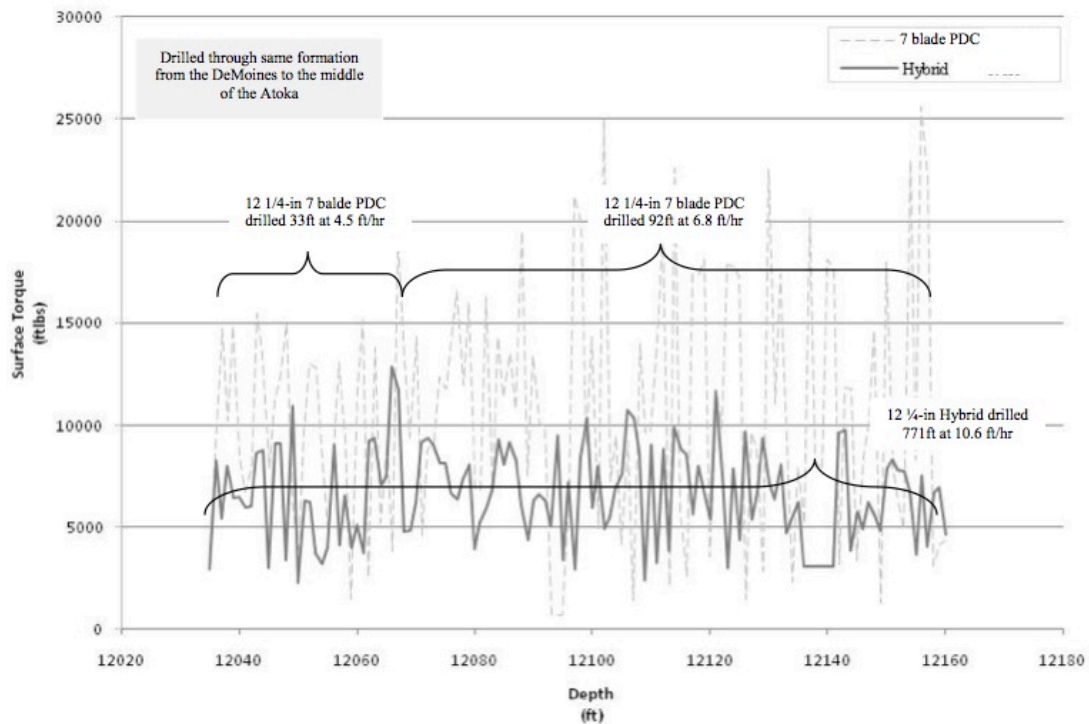


System	Series	Previous classification	Present classification		Formation
(Middle) Pennsylvanian	Desmoinesian	Marmaton group	Cyngian substage	Marmaton group	Holdenville
					Lenapah
	Cherokee group	Cherokee group	Cabaniss subgroup	Nowata	
				Altamont	
Atokan	Atoka fm. (subsurface only)	Atokan	Atoka fm.	Bandera	
				Pawnee	
			Venteran substage	Krebs subgroup	Labette
					Fort Scott
					Excello
					Mulky
					Lagonda
					Bevier
					Verdigris
					Croweburg
					Fleming
					Robinson Branch
					Mineral
					Scammon
					Tebo
					Weir
					Seville
					Bluejacket
					Dry Wood
					Rowe
					Warner
					Riverton

Figure 4.8

Classification of Middle Pennsylvanian beds in the northern Midcontinent [8,11]

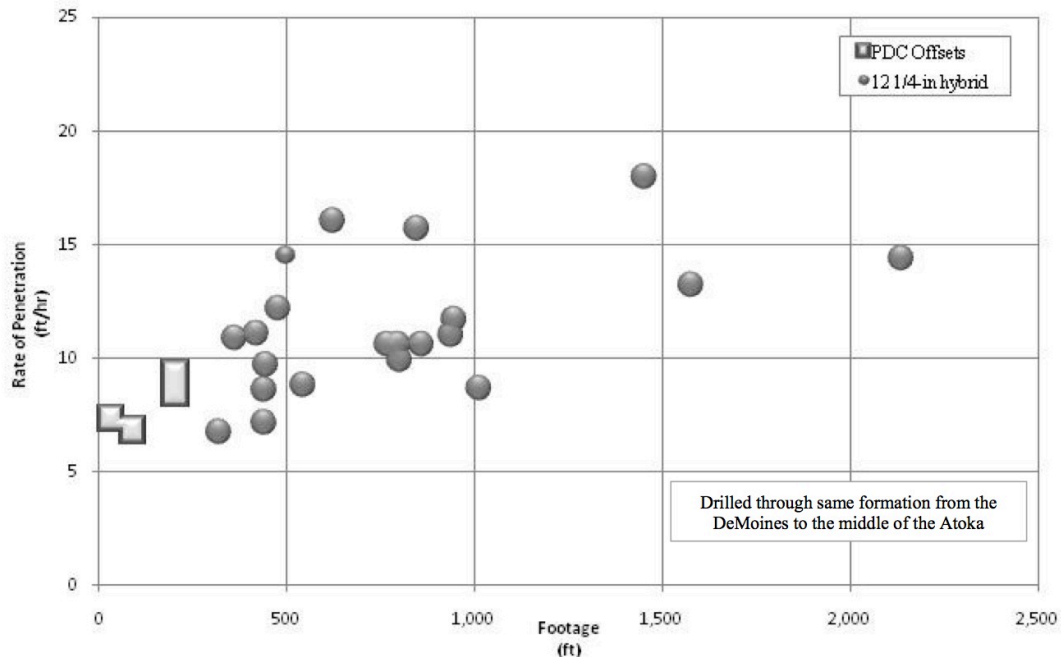
The 12 ¼-in Kymera has been tested in this area with over 40 runs and all with magnificent performances. The hybrids drilled with significant lower torque fluctuations than the PDC as seen in **Figure 4.9**. The high torque fluctuations of up to 15000-20000 ft/lbs, when drilled with PDC, were reduced three to four times with the hybrids. The hybrid bits drilled an average footage of 771 ft and 10.6 ft/hr ROP, which is superior compared to PDC runs. The best PDC runs had only an average footage of 92 ft and 6.5 ft/hr ROP.



**Figure 4.9**  
Oklahoma field test - Torque fluctuations PDC versus Hybrid [13]



**Figure 4.10** shows the individual footage versus ROP of both the PDC and the hybrid runs. The graph clearly indicates that the hybrid drills with much higher ROP than the PDC in most cases. The most impressive result is that the longest run obtained by a hybrid bit was 2136 ft. This is 10 times more than the best offset PDC footage of 205 ft.



**Figure 4.10**  
Oklahoma field test - ROP PDC versus Hybrid [13]

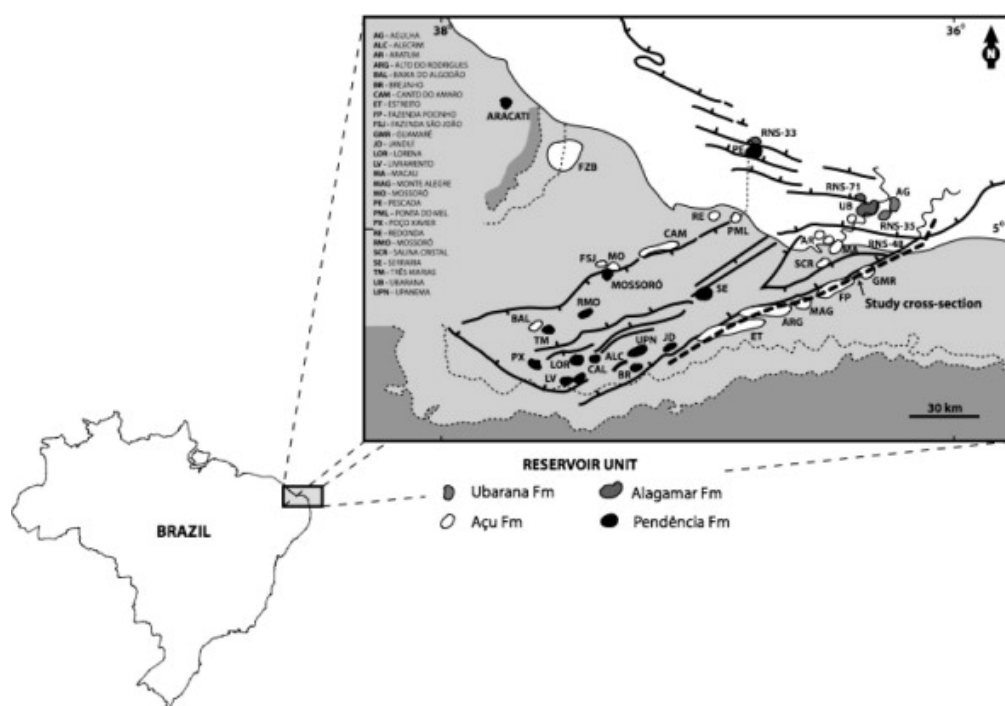
The formation in upper and lower section of the wells is primarily of sand and shale while stringers of chert is more common in the middle section. The chert concentration varies from 5% to 95% and the length could be from a few feet to several hundred. Chert sections have previously been drilled with PDC or TCI bits. The PDC has been the preferred bit in these sections with good footage and ROP, but even with recent cutter technology, long intervals of chert will cause severe vibrations and destroy the bits easily. TCI bits are more resistant in the hard formation, but entail undesired low ROP.

The 12 1/2-in Kymera drilled this section smoothly with low vibrations observed. The footage was 1.5 to 3 times the footage of offset PDCs, but with slightly lower ROP. The bit dull was miscellaneous. The PDC blades had mostly chipped teeth on the shoulder, but nearly worn to the body of the bit. On the other side, the TCI condition was intact with minimal wear on each cone.

## 4.1.2 Brazil

The following information is taken from Thomson et al (2011, p. 2-4):

A test run was conducted in the Potiguar Basin, (**Figure 4.11**) northeast Brazil. The basin is extensive and expands mostly in Rio Grande do Norte and parts of Ceara. The total area is approximately 48,000 km<sup>2</sup> with 55% submerged. The Potiguar Basin is composed of Cretaceous Pendência formation (**Figure 4.12**), which is characterized by conglomerates and sandstone interbedded with plastic shale or gray siltstone. Particle sizes of the sandstones vary from fine to coarse grains and hence offer a significant fluctuation in hardness when drilling.



**Figure 4.11**  
Potiguar Basin [28]

The 12 ¼-in hybrid bit drilled 362 m in one run with a 5.85 m/hour average ROP and was pulled due to casing point. Lithology column in this run had a variance of highly interbedded sandstone and shale sequence, which is typical in Pendência formation. It was observed that the ROP was slightly higher when drilling through the sandstone layers compared to shale layers and varied from 3 to 8.5 m/hour. Cutting structure of the bit showed minimum wear after the run as shown in **Figure 4.13**. No sign of impact damage on the bit cutting structure indicates that the hybrid was very stable and reacted very smoothly when drilling through the formation transition zones.

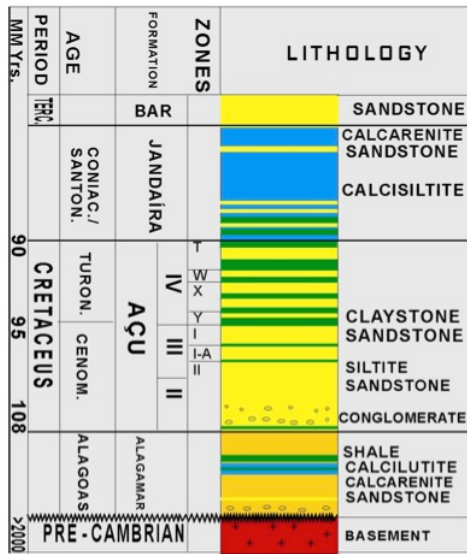


Figure 4.12

Cretaceous formation in Potiguar Basin [22]



Figure 4.13

Hybrid bit cutting structure after 362m run in Pendência formation [31]

The Kymera run was compared with two offset wells where roller cone bits were used in a similar drilling scenario. The comparison between the Kymera and roller cone bits shows:

Offset Wellbore 1 517 IADC Roller Cone		
Drilling time	Average ROP	Cost Per Meter
Hybrid bit drilled 71% faster	3.4 m/hour	18% lower with hybrid

Figure 4.14

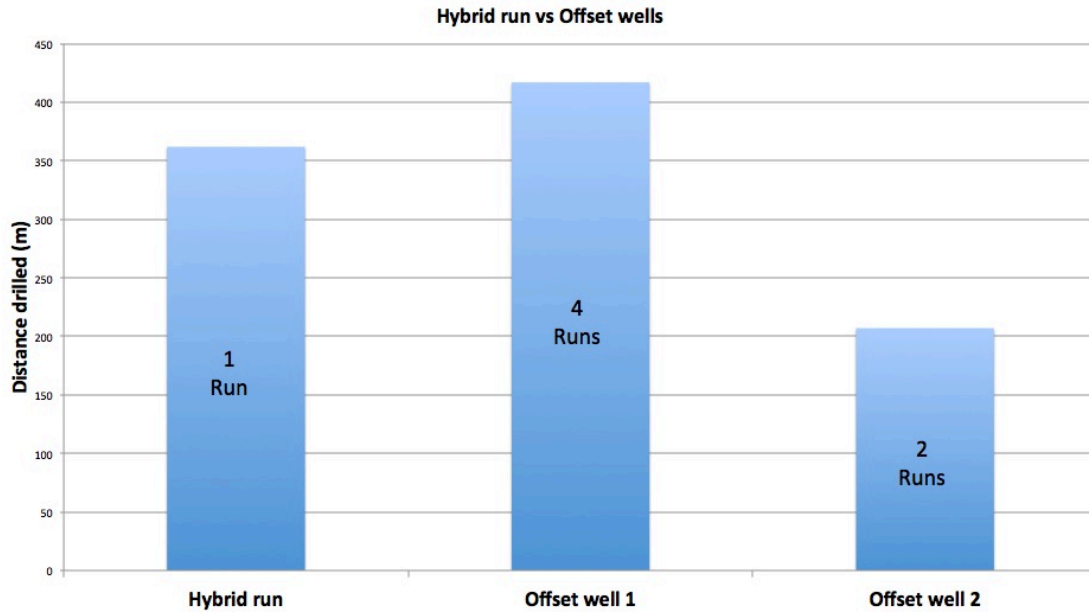
Offset wellbore 1 comparison in Pendência formation [31]

Offset Wellbore 2 437 IADC Roller Cone		
Drilling time	Average ROP	Cost Per Meter
Hybrid bit drilled 200% faster	1.7 m/hour	46% lower with hybrid

Figure 4.15

Offset wellbore 2 comparison in Pendência formation [31]

The hybrid bit verifies a superior quality in durability compared to the roller cones. The results from **Figure 4.16** show that the hybrid bit drilled a distance of 362 m in a single run. Offset well 1 was drilled with longer footage, but required 4 runs while offset well 2 required two runs with 50% less footage than the hybrid.



**Figure 4.16**  
Hybrid run versus offset wells in Pendência formation [31]

## 5 Conclusions

In this thesis, I have explained the most important properties of the roller cone, PDC and diamond bit. The characteristics of each type have been described as accurate as possible based on the fundamental principles of conventional drill bits. I have excluded newer technology and distinctive design, which vary in all bit companies. Parameters for selection of bits have been presented, as additional information to highlight other important non-technological factors when choosing the proper bit for drilling with increased efficiency. The last chapter is an introduction of the new hybrid bit design. Field test results are then presented to verify some of the proclaimed advantages of the Kymera.

Over a century, the drill bits have had a significant impact on the drilling industry. Technological improvements and innovations of drill bits have gained distinction since the first drag bit was introduced in the oilfield. The roller cone bit, with the effective crushing mechanics, good stability, low torque and highly durable tungsten carbide insert teeth, gave the industry the possibility to drill in more difficult applications. It was, however, not effective enough with regards to the rate of penetration obtained while drilling and what the engineers expected. The polycrystalline diamond compact bit was developed and partially solved many problems. The shearing action of the cutters, combined with the high rate of penetration, reduced the time spent drilling each well rapidly. However, a more robust attack of the rocks and improved rate of penetration did not exist without severe problems to the toolstring.

Improvements in drilling performance around the world continue to focus on reducing many of the negative aspects of the conventional bits. These includes whirl, stick-slip and bit bounce leading to drilling efficiencies and severe tool damage when drilling in highly interbedded formations. Many solutions have been developed to control and manage these problems. Baker Hughes represents a legacy of technology innovations by introducing a game-changing hybrid bit, the Kymera.

The field tests show that the Kymera bit technology offers advantages where conventional bits do not perform as expected. The presented tests runs have shown good results in terms of ROP, footage, torque fluctuations and wear resistance. To summarize, the Kymera can offer:

- Higher overall ROP
- Lower vibration
- Better toolface control
- Improved torque control

## Nomenclature

BHA	=	Bottom hole assembly
BHI	=	Baker Hughes Incorporated
HCC	=	Hughes Christensen Company
IADC	=	International Association of Drilling Contractors
PDC	=	Polycrystalline diamond compact
POOH	=	Pulling out of hole
RIH	=	Run in hole
ROP	=	Rate of penetration
RPM	=	Revolutions per minute
TCI	=	Tungsten carbide insert
TD	=	Total depth
TSP	=	Thermally stable polycrystalline
WOB	=	Weight on bit
TFA	=	Total flow area
MD	=	Mud weight
RC	=	Roller cone
RSS	=	Rotary steerable systems
UCS	=	Unconfined compressive strength

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