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Application of Anti-Whirl PDC Bits Gains Momentum

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Abstract

Over the past four years the phenomenon of bit whirl has been identified as a major cause of premature failure and reduced performance of PDC bits. Examples of the successful application of commercially available Anti-Whirl bits for straight hole rotary drilling, straight hole motor drilling and steerable directional drilling are presented. Also discussed are a number of features that may be used either separately or in conjunction with the Anti-Whirl design to help reduce the tendency to whirl.

Introduction

Backward whirl was first shown to be a major cause of PDC bit damage and accelerated wear by Brett, et al¹ in 1989. Potential solutions to reduce the effect of whirl were presented by Warren, et al² at the same time. Since then, bit whirl has become widely accepted as a significant phenomenon that affects the performance of PDC bits. Considerable work has been done by these authors and others to develop bit designs and operating guidelines to minimize the effect of whirl.

One design concept that has shown to resist whirl utilizes the cutter positions to provide a radial force directed toward a smooth sliding surface to stabilize the bit. These bits, referred to as Anti-Whirl bits, were patented by Amoco^{3,4} and licensed to several PDC bit companies. Most of these companies have experimented with the Anti-Whirl concept and some have proposed refinements to the basic concept, but only one company has developed a fairly extensive product line (Table 1). Since their introduction, these bits have grown to be a significant portion of this manufacturer's product line as shown in Fig. 1. Other manufacturers are continuing to evaluate the Anti-Whirl design or are evaluating alternative ways of minimizing whirl.

The introduction of the Anti-Whirl bits did not completely eliminate problems associated with whirl. The early bit designs had inherent weaknesses that were sometimes more severe than the problem they attempted to solve. More recent designs have evolved which definitely provide an improved bit in a wide variety of situations and are no longer strictly research trials. There is still potential to make the bits more robust, but it appears that some type of an Anti-Whirl bit is here to stay.

The material presented below provides examples where Anti-Whirl bits have been successfully run. The examples were compiled from cases where Amoco drilling engineers have tried a new technology to help improve the performance of their wells. In most cases the bits were selected and run without direct involvement by the authors and the credit for their successful use lies with the individual drilling engineers.

Anti-Whirl PDC Bit Applications

Straight Hole Rotary

Canada - Northeast British Columbia

PDC bits have seen limited success in the area of northeast British Columbia. The reasons are twofold: difficult carbonates and shales from the Devonian age typically limit bit runs and an abundance of drilling rigs has created artificially low rig rates. The additional expense of PDC bits compared to roller cone bits (typically 3-5 times higher), coupled with lower rig rates, require that the odds

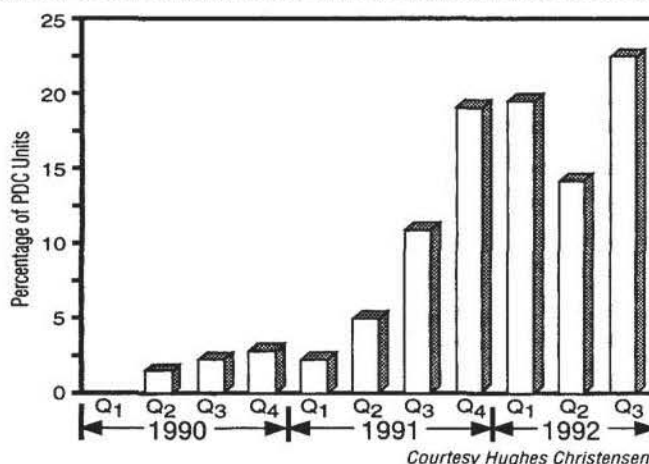


Figure 1 - Increase in Anti-Whirl PDC bit production by a leading manufacturer.

of a bit failure be minimal in order to justify the economics. Assuming that the rock is not too hard for the PDC cutters an Anti-Whirl PDC bit is one way to lower the risk.

Table 1.

Available Product Line of Anti-Whirl PDC Bits.

Size	3-4 blade M131	5 blade M231	6-12 blade M332	8-12 blade M432	4 blade M121	5 blade M221	6-8 blade M322	6-8 blade M423	4 blade M111
5-7/8			X						
6			X						
6-1/8	X		X						
6-1/4	X								
6-3/4			X						
7-7/8	X		X			X			
8-3/8			X			X			
8-1/2	X	X	X	X	X	X	X		
8-3/4			X	X			X		
9-1/2			X		X	X			
9-7/8	X		X		X				
10-5/8	X				X				
12			X						
12-1/4			X	X	X	X	X	X	X
14-3/4						X			
16			X			X			
17-1/2			X			X			

Courtesy Hughes Christensen

A 6-1/8" Anti-Whirl PDC bit (IADC M332) was used to drill a series of medium strength carbonates and shales just north of Fort St. John in British Columbia. A packed bottomhole assembly was used, along with a flow rate of 210 gpm (790 lpm).

Figure 2 shows the cutter layout and cutter profile. The bit is set with 25 half inch PDC cutters on a medium parabolic profile. The low friction pad that makes continuous sliding contact with the borehole wall is indicated on the right side of the cutter layout. For general designs, the radial bit imbalance percent typically ranges from a low of about 5% of the applied bit weight to a high of about 20%, depending on the bit size, style, and preference of the bit manufacturer.

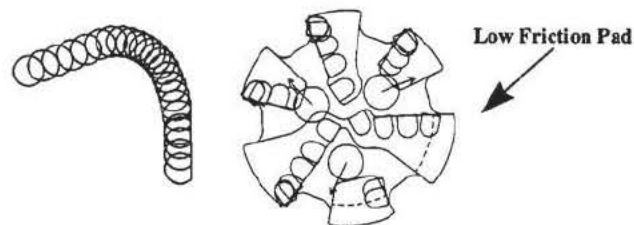


Figure 2 - Cutter layout and profile of the 6-1/8 in. Anti-Whirl PDC bit used in Canada.

The 6-1/8" Anti-Whirl bit began drilling at a depth of 6,358 ft (1,938m) inside the Wabamum limestone section and was pulled inside the Slave Point section in reusable condition at a depth of 8,760 ft (2,670 m) in 84 rotating hours. The lithology of the Slave Point is characterized as a limestone interbedded with

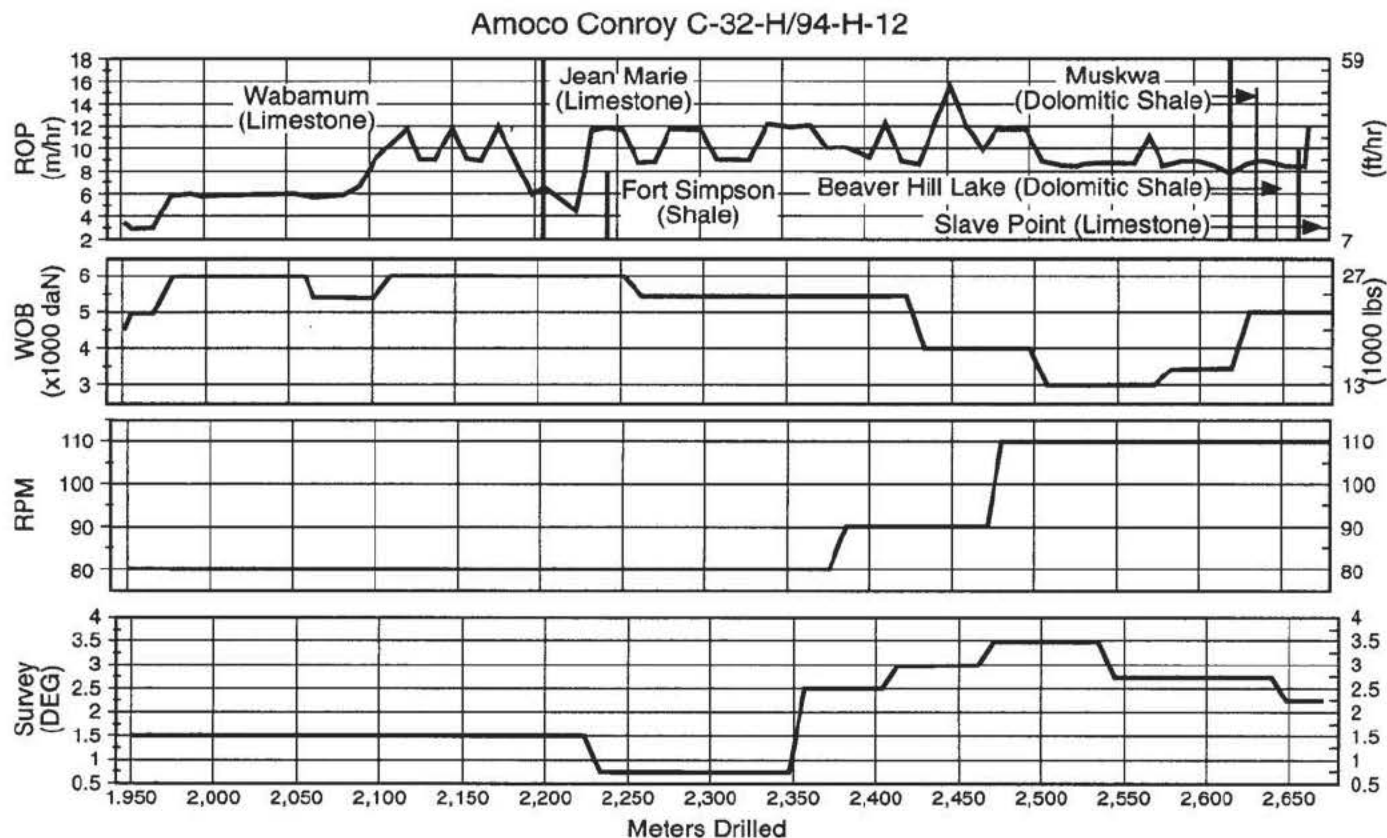


Figure 3 - Drilling performance of the 6-1/8" Anti-Whirl PDC bit used in Canada

anhydrite. A total of 2,402 ft (732 m) of formation was drilled at an average penetration rate of 28.6 ft/hr (8.7 m/hr) before the bit was pulled.

Figure 3 shows the drilling performance of the Anti-Whirl bit. The rotary speed averaged 80 rpm through the Wabamum, Jean Marie, and part of the Fort Simpson. The use of lower rotary speeds in firmer formations has been used with success to drill harder formations by providing less drillstring effects and increased bit stability.

Surveys taken through the Fort Simpson showed that the inclination began to increase from about one degree to a high of about three and a half degrees. Increasing the rotary speed and decreasing the applied bit weight brought the inclination back down to about two and a half degrees before pulling the bit.

The cutter wear measured only 1/8 on the inner rows and 3/8 on the outer rows. Uniform cutter wear and lack of diamond spalling indicated that the bit was rotating smoothly during the run. The bit life and "sharpness" enabled it to replace four to five roller cone bits while averaging two and three times the rate of penetration. The savings was estimated at \$111,000 U.S.

Netherlands - Offshore

Amoco has experienced good success in the Netherlands, drilling ten consecutive commercial gas wells during the past six years. The wells are located in the Dutch North Sea in eight separate structures. Staying abreast of and applying new technology has been an important part of this success.

Trying new technologies has also played a role in operations which recently ran an 8-1/2" Anti-Whirl PDC bit (IADC M332) in Amoco's L/5-6 exploration well which is located offshore Netherlands. The well was drilled on rotary with a packed bottomhole assembly using a jackup rig in about 100 ft (30 m) of water. The bit was set with 33 half inch PDC cutters on a medium parabolic profile. Figure 4 show the cutter layout and bit profile.

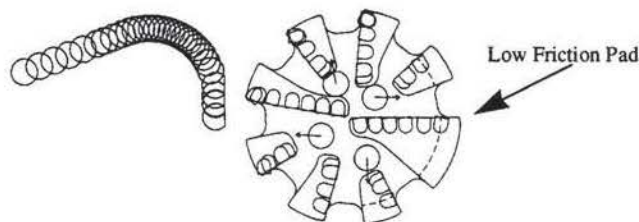


Figure 4 - Cutter layout and bit profile of the 8-1/2 in. Anti-Whirl PDC bit (IADC M332) used offshore in the Netherlands.

Drilling began at a depth of 14,722 ft (4,487 m) after drilling out 56 ft (17 m) of cement and the 9-5/8" casing shoe. The interval drilled consisted of the Rot-liegend shale formation which is a hard shale and claystone sequence with increasing sand and silt stringers with depth.

The bit drilled 755 ft and was pulled with 65% wear and only minor cutter damage which was surprising since the sand content of the formation increased considerably. Because of the sand, the following insert bit experienced poor rates of penetration and was pulled for another PDC bit. The non Anti-Whirl design PDC bit design (IADC M433) drilled 39 ft (12 m) in 8 hours at an average penetration rate of 4.9 ft/hr (1.5 m/hr) before being pulled with significant wear and cutter damage. This type of wear after drilling a short distance is usually an indication that the bit experienced whirl.

An offset well had a PDC bit run in the equivalent section, drilling 751 ft (229 m) at 7.6 ft/hr (2.3 m/hr) at an average cost per foot of \$578. The Anti-Whirl bit drilled 755 ft (230 m) at an average rate of penetration of 24 ft/hr (7.3 m/hr) and a cost per foot of \$227. The run was relatively short but because of the three fold increase in penetration, a net savings of \$265,000 U.S. was realized.

Qatar

Amoco's operations in the country of Qatar have experienced good success running 8-1/2" PDC bits in firmer carbonate sections. The carbonates, some partially dolomitized, have sonic travel times averaging 50 μ s/ft which are usually considered too hard for successful PDC bit applications⁵. Historically, an IADC series 5-1-7 roller cone bit was the bit of choice.

The Karanah No. 2 in Southern Qatar was drilled in record time for the area - eight days ahead of the previous best well with no major problems encountered. The lithology is almost 100% limestone and was drilled with a PHPA mud system. A reduced casing program and several good bit runs including an Anti-Whirl (IADC M332) PDC bit in the 8-1/2" hole section helped to drill the hole quickly and minimize hole exposure time, thus eliminating problems.

The lower hole section was drilled with one Anti-Whirl and one conventional PDC bit. The Anti-Whirl PDC bit was performing well until a tong die was inadvertently dropped into the hole causing the bit to be damaged and ending the run (Fig. 5). The performance of the PDC bits is shown below in table 2.

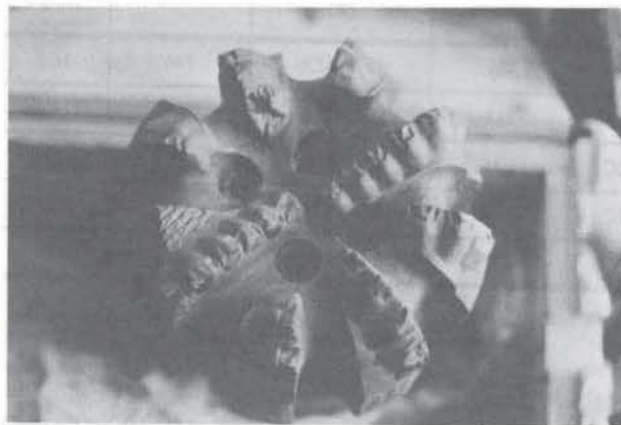


Figure 5 - Anti-whirl PDC bit damaged by "junk" in the hole.

Table 2

Karanah No. 2

Bit Type	IADC	Interval (ft)	Footage	ROP (ft/hr)
PDC A	M3322	5535-6995	1460	19.1
PDC B	S332	6995-8540	1545	24.0

PDC A - Anti-Whirl; junk damage
PDC B - Conventional

The closest Amoco offset well is the Al Rakiyah No. 1, located 8 mi (15 km) to the southwest. Three roller cone bits and one PDC bit were required to drill the lower hole section. The ABU Suwayy No. 1, located about 40 mi (64km) to the north, required 5 roller cone bits to drill this same interval. The performance of the bits on these two wells is shown in Tables 3 and 4. The data shows that the Anti-Whirl bit drilled at twice the rate of the series 5-1-7 roller cone bits through the same interval. The interval drilled by the Anti-Whirl bit appeared to be tougher than the lower section drilled by the standard bit, but this is not certain.

Table 3**Al Rakiyah No. 1**

Type	IADC	Interval (ft)	Footage	ROP (ft/hr)
RC	517	5816-6211	395	9.3
RC	517	6211-6750	539	8.6
RC	517	6750-7658	908	17.3
PDC	S422	7658-8899	1241	21.0

Table 4**ABU Suwayy No. 1**

Type	IADC	Interval (ft)	Footage	ROP (ft/hr)
RC	437	4595-5339	744	16.9
RC	215	5339-5544	205	14.1
RC	134	5544-5582	38	10.8
RC	517	5582-6448	758	15.8
RC	537	6448-7481	1033	12.4

Straight Hole Motor**Sharjah**

The application of drilling technology in the country of Sharjah has resulted in continuous improvements in an active drilling program over the past ten years. The improvements have resulted in substantial savings in rig time and reductions in cost per foot. Optimization of the mud system, solids control, hydraulics, and improvements in bit technology have decreased the number of bits used to drill the 17-1/2" up-hole section from a high of seven down to two, while reducing the rotating hours nearly 25 percent. The application of a 16" Anti-Whirl PDC bit (IADC M332) as part of the ongoing effort to continuously

improve the drilling program provided another significant reduction in drilling time.

The Sharjah wells are onshore and drilling in the up-hole section begins below the 20" casing which is set at approximately 600 ft (183 m) and continues down to an average depth of 4,000 ft (1,219 m). A 17-1/2" roller cone bit series 1-3-5 averages 20 to 25 ft/hr (6.1 to 7.6 m/hr) through this section which is mixed with sandstone, anhydrite, limestone, and claystone for the first 600 ft (183 m) and primarily clay and shale below. An oil based mud system is used below the 20" casing to minimize hole problems.

A previous attempt at running a conventional 17-1/2" PDC bit (IADC M432) resulted in the bit being 85% worn after drilling 128 ft (39 m) in 8.3 rotating hours. Bit whirl in the upper section where the formation is firmer and less uniform is believed to be the cause of the short run with the conventional PDC bit. Successful running of the Anti-Whirl PDC bit would require it to drill smoothly through the intervals where the rock is competent enough to cause cutter damage.

Laboratory testing of the Anti-Whirl bit was required since a design of this size had not been qualified for the field. Figure 6 shows the cutter layout of the matrix body Anti-Whirl bit which was set with 106 1/2" PDC cutters on a medium parabolic profile.

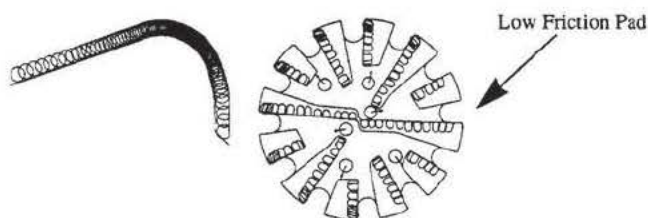
**Figure 6 - Cutter layout and profile of the 16 in. Anti-Whirl PDC bit used in Sharjah.**

Figure 7 shows the resulting bottomhole pattern while drilling Carthage limestone at 6 ft/hr (1.8 m/hr) under atmospheric conditions. The bottomhole pattern generated with a similar style conventional 12-1/4" PDC bit that was being tested at the same time is also shown. The bottomhole patterns show that the conventional bit was whirling violently at the low rate of penetration compared to the smoother drilling Anti-Whirl bit. At higher rates of penetration, the Anti-Whirl bit continued to drill smoothly, but the conventional bit continued to whirl, even while drilling at 96 ft/hr (29.3 m/hr). Conventional PDC bits generally drill smooth at higher rates of penetration because the bit is advancing axially at a speed that limits radial movement in the form of bit whirl.

**Figure 7 - Bottomhole patterns generated while drilling Carthage limestone. The left one was drilled with the 16 in. Anti-Whirl PDC bit. The right one was drilled with a 12-1/4 in. conventional PDC bit.**

The 16" Anti-Whirl PDC bit was sent to Sharjah following the laboratory qualification and was run on an 11-3/4" low-speed, high-torque PDM. With a flow rate of 1,000 gpm (3,785 lpm) and a surface rotary of 150 rpm, the downhole bit speed averaged 300 rpm throughout most of the drilling. The drilling plan called for using the Anti-Whirl bit to drill the entire 16" hole section on the Moveyeid No.3 with hopes of being able to rerun the bit on future hole sections.

On the first well, Moveyeid No. 3, the bit drilled the entire interval of 3,428 ft (1,045 m) in 45.5 hours giving a rate of penetration of 75.3 ft/hr (23.0 m/hr). The drilling rate, which included connection time, experienced rates in excess of 150 ft/hr (45.7 m/hr) as shown by Fig. 8. Also shown are the drilling rates of two recent roller cone runs through the same interval which took 129 hours, averaging 26 ft/hr (7.9 m/hr).

The Anti-Whirl bit ran successfully on two wells, but had to be repaired after losing four cutters near the center of the bit. After the repair it was run on three more wells in addition to being used to reach casing point on a sixth well that had been sidetracked.

Sharjah, U.A.E.

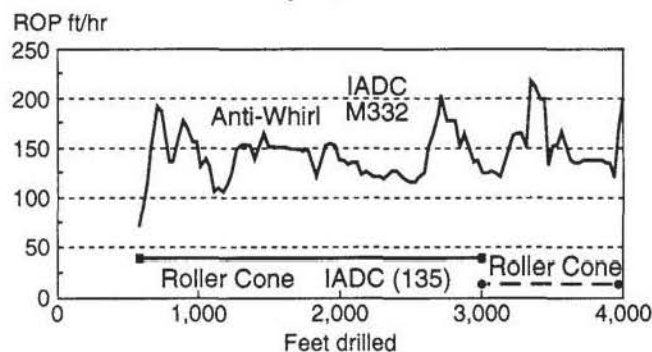


Figure 8 - Drilling rate including connection time for Moveyeid No. 3.

Figures 9 and 10 compare the footage and rotating hours drilled through the 17-1/2" hole section on offset wells with the Anti-Whirl PDC bit runs through the 16" section. The Anti-Whirl bit drilled a total of 16,411 ft (5,002 m) in 252 rotating hours at an average penetration rate of 65.1 ft/hr (19.8 m/hr). The cost per foot in the up-hole section was reduced by over half through savings in bits, trips, and a two-thirds reduction in rotating hours. An estimated savings of

Amoco Sharjah Oil Company

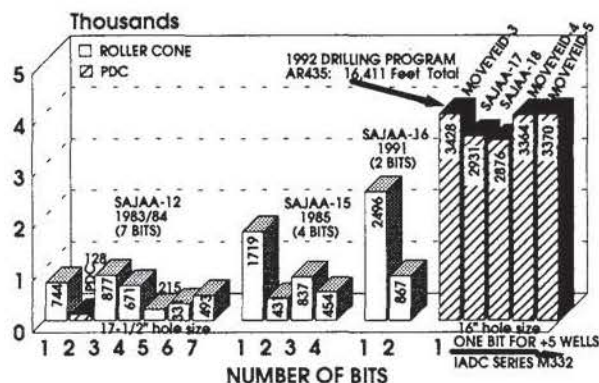


Figure 9 - Comparison of footage drilled between rollercone and Anti-Whirl PDC bits used in Sharjah.

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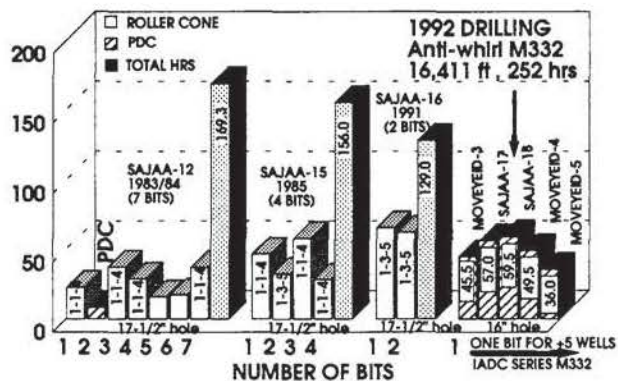


Figure 10 - Comparison of rotating hours for rollercone bits and Anti-Whirl PDC bits used in Sharjah.

approximately \$100,000 U.S per well was realized over the plus five wells drilled.

Competitors operating offshore Sharjah have experienced similar results while drilling with Anti-Whirl bits on both motors and rotary assemblies.

Steerable Motor

Many problems associated with using PDC bits for directional drilling are believed to be the result of downhole vibrations caused by bit whirl. Vibrations cause inconsistent build rates, shortened bit lives, drillstring hang-ups, and premature failures of the measurement-while-drilling (MWD) tools. This type of motion causes high impact loading and chipping of the cutters resulting in reduced bit life. The hole can also become enlarged as the gauge of the bit makes repeated impacts against the borehole wall. Ledges on the borehole wall are a direct result of this type of vibration which can also lead to the centerline of the hole changing as the bit "stairs" downward.

Figure 10 shows an example of severe hole ledging and spiraling. The hole caliper was obtained from an Egyptian well where the section was drilled with a 12-1/4" PDC bit (IADC M433). The drilling was with a packed bottomhole assembly rotating at 180 rpm. Inclination of the hole averaged 34° through this interval.

Controlled field testing by Pastusek, et al.⁶ has shown similar results while directional drilling. His results demonstrate that Anti-Whirl PDC bits can be used on directional wells to increase bit performance, bit life, and to reduce the tendency for hole ledging. Eliminating the harmful effects of downhole vibration is crucial to successful directional drilling.

Trinidad - Offshore

Trinidad is an area that has experienced a number of MWD and LWD failures while directionally drilling. Careful evaluation of the quality control methods by one downhole service company led to the conclusion that downhole vibrations were the primary cause of the electronics failures. This conclusion was also based on measurements obtained while running downhole accelerometers in their MWD electronic packages⁷. The example below shows that downhole vibrations are real and how an Anti-Whirl PDC bit can be used to significantly reduce the level of vibration.

A 12-1/4" Anti-Whirl bit (IADC M131) was used on the B-26 well drilled from the Pouli B platform. The platform is located in about 190 ft (58 m) of water. Roller cone bits and one Anti-Whirl PDC bit were used to reach a depth of 9,675 ft (2,949 m). The Anti-Whirl bit was a light set matrix body design set

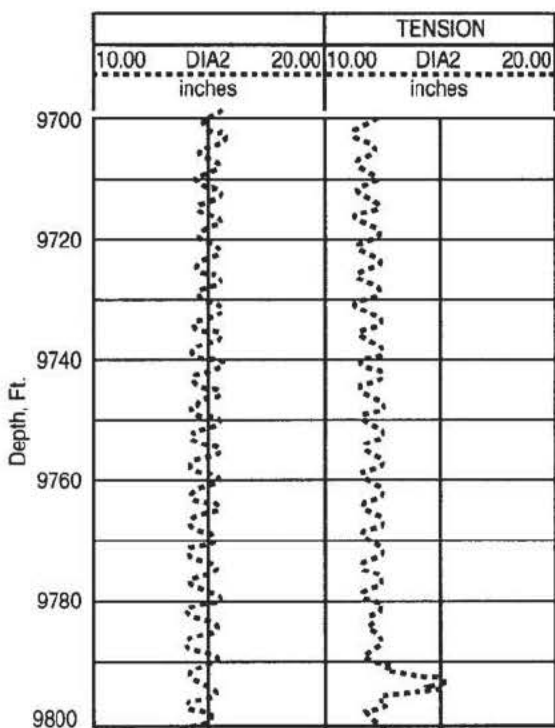


Figure 10 - Severe hole ledging and spiraling in an Egyptian well drilled with a 12-1/4" PDC bit (IADC M433)

with 32 half inch cutters on five blades. Figure 11 shows the cutter layout and cutter profile which has a medium parabolic taper.

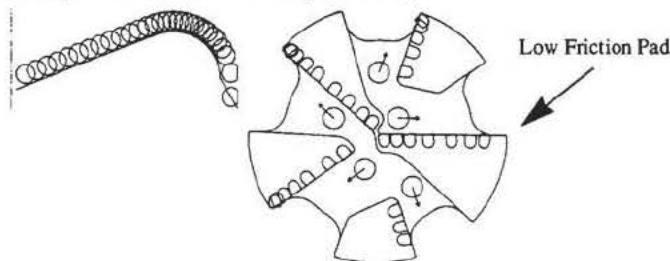


Figure 11 - Cutter layout and profile of the Anti-Whirl PDC bit used on Trinidad well.

The Anti-Whirl bit went into the hole at a depth of 4,663 ft (1,421 m) and drilled to a measured depth of 7,546 ft (2,300 m) with a steering assembly using a 3/4° bent housing PDM. The inclination of the hole dropped from 53° to 44° while turning from N37E to N45E. A total of 21% of the drilling was in the slide mode through this interval.

The bit was pulled to replace the motor and at the same time increase the angle of the bent housing from 3/4° to 1° to give better response in the sands. Drilling continued to 7,946 ft (2,422 m) where a complete loss of circulation was experienced requiring the bottomhole assembly to be tripped out and laid down. A total of 18% of the drilling was in the slide mode while maintaining the inclination at 44°.

Following a short motor run down to 8,950 ft (2,728 m) with a roller cone bit (IADC 1-1-7), the Anti-Whirl bit was picked back up with a rotary assembly and used to reach a total depth of 9,675 ft (2,949 m). Overall, the Anti-Whirl bit drilled 4,008 ft (1,222 m) at an average penetration rate of 49 ft/hr (14.9 m/hr). Cutter wear was measured to be about 50% on the inner rows and outer rows of PDC cutters. Although it was well worn, bit engineers estimated an

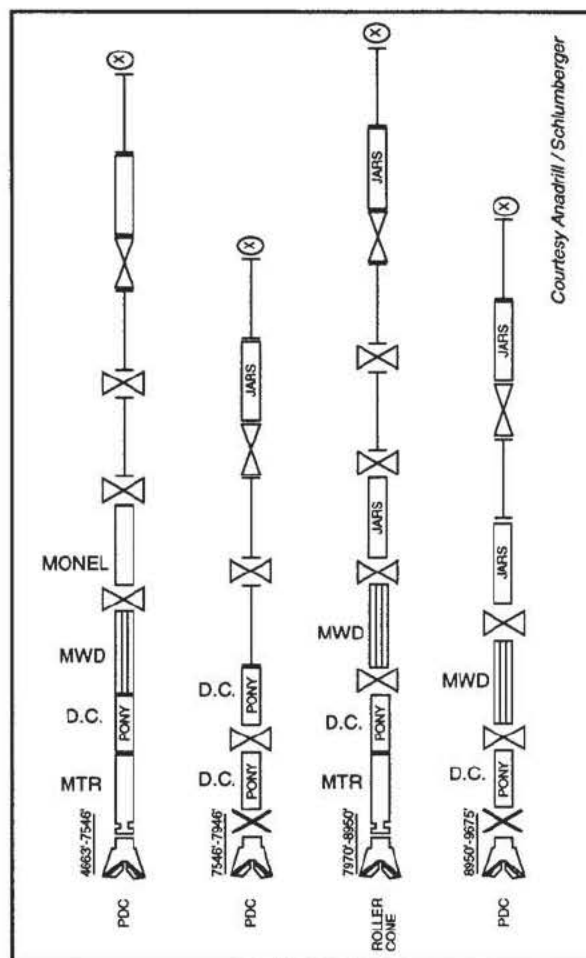


Figure 12 - Bottomhole assemblies used from 4,663 ft (1,421m) to total depth.

additional 800 ft (244 m) of usable bit life was left on the bit. Savings was estimated at \$202,000 U.S. based on the drilling performance of the roller cone bit used to drill part of the interval. Figure 12 shows the bottomhole assemblies used from 4,663 ft (1,421 m) to 9,675 ft (2,949 m).

Figure 13 compares the recorded shock cycles per foot during a portion of the roller cone and Anti-Whirl bit runs. A shock count is determined by measuring the number of shocks above a preset level, i.e. 25 G's of acceleration. The shock analysis gives a measure of the transverse vibrations induced on the drillstring which are primarily the result of radial impact loading. A whirling bit is a primary cause of impact loading which causes increased transverse vibrations induced on the drillstring. The significance of the shock analysis is that the life expectancy of electronic tools like the MWD and LWD is a direct function of the cumulative shock loading.

Increased shock levels can also cause reduced bit life. In the case of roller cone bits, which are less prone to impact damage, bit whirl can result in a slightly overgauge hole which causes "tracking" of the inserts and a reduction in rate of penetration.

The shock analysis program recorded an average of 36 cycles per foot for the Anti-Whirl bit run from 4,663 - 7,946 ft (1,421 - 2,422 m). In the interval from 7,970 - 8,950 ft (2,429 - 2,728 m) drilled with a rollercone bit, the analysis program recorded an average of 133 cycles per foot, nearly four times higher than with the Anti-Whirl bit. The highest shock counts for the roller cone bit also coincide with lower rates of penetration.

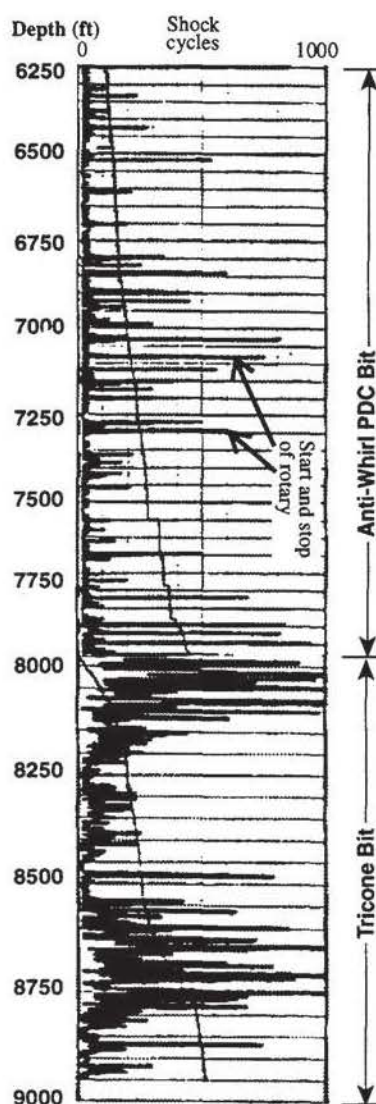


Figure 13 - Recorded shock cycles per foot during rollercone and Anti-Whirl bit runs in Trinidad.

was laid down and a roller cone bit was run back in the hole averaging only 30.7 ft/hr (9.4 m/hr) for 768 ft (234 m).

The second Anti-Whirl PDC bit was run on a rotary assembly from 11,016 - 14,416 ft (3,358 - 4,412 m) averaging 45.3 ft/hr (13.8 m/hr). The bit was pulled rerunnable with wear measuring only 1/8 on the inner rows and 2/8 on the outer rows. The rate of penetration of the first and second Anti-Whirl PDC bits were nearly 59% and 48% faster than the roller cone bit run. A total of 22 days of rig time was required, reducing the dry hole well cost estimate from \$2 MM U.S. to \$1.4MM U.S.

Operating Practices

The use of poor operating practices can cause any bit to whirl. Once whirl is initiated, it is often difficult to stop without shutting down the rotary to eliminate the regenerative process.

Extensive laboratory testing has shown that a bit rotating off bottom, a bit is susceptible to off-bottom whirl by gauge contact with the borehole wall⁸. Rotation of the drillstring (or PDM rotor) supplies the energy that causes the cutter

Gulf Coast- Offshore

Successes with Anti-Whirl PDC bits have also been seen in areas that we normally drill well without any significant hole problems. Figure 14 shows how seven days of rig time were saved through the right application of bits, proper directional control, and a "team" approach to the drilling.

West Delta 103 No. 5 was directionally drilled from a jackup rig in the Gulf Coast. The drilling required 28 days and the use of six bits (3 roller cone and 3 PDC) to drill the 12-1/4" hole section down to a depth of 14,000 ft (4,267 m).

West Delta 103 No. 6 was also directionally drilled from a jackup in 190 ft (58 m) of water to a total depth of 14,416 ft (4,394 m). Two 12-1/4" roller cone bits and two Anti-Whirl PDC bits (IADC M221) were used to drill the interval. Figure 15 shows the cutter layout and cutter profile for the Anti-Whirl bit design.

The first run with the Anti-Whirl PDC bit was with a low-speed, high-torque PDM set with a 1° bent housing. The bit drilled from 5,910 - 10,248 ft (1,801 - 3,124 m), averaged 49 ft/hr (14.9 m/hr) and was pulled with cutter wear measuring 1/8 on the inner rows and 2/8 on the outer rows. Because of slight wear on the bit gauge, the Anti-Whirl bit

Gulf Coast-West Delta 103 12 1/4" Anti-Whirl IADC M221 Days vs Depth

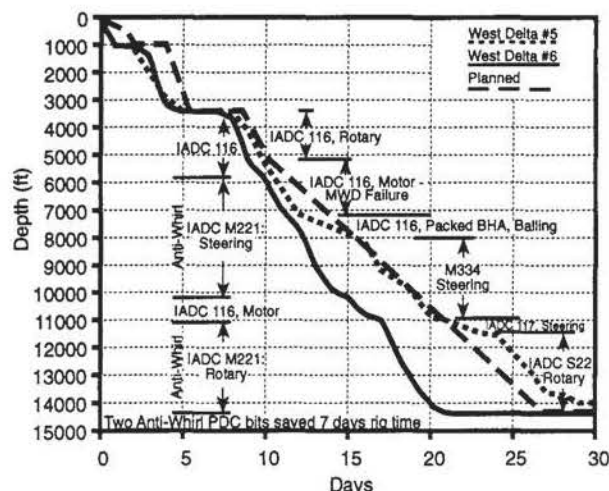


Figure 14 - Seven days of rig time was saved through proper application of Anti-Whirl PDC bit.

damage resulting from the whirl. The bit is also unstable when it first touches the bottom of the hole when preparing to drill ahead. The instability increases as the bit speed is increased and as the applied bit weight is decreased. This is true whether or not the bit is an Anti-Whirl design.

Proper operating procedures can be used to extend the life of a PDC bit, off bottom or drilling ahead. Rotary speeds less than 60 rpm should be used on rotary while going to bottom. Temporarily reducing the flow rate to reduce bit speed is an option with PDM's. Once on bottom, the applied weight should be increased first before increasing the bit speed.

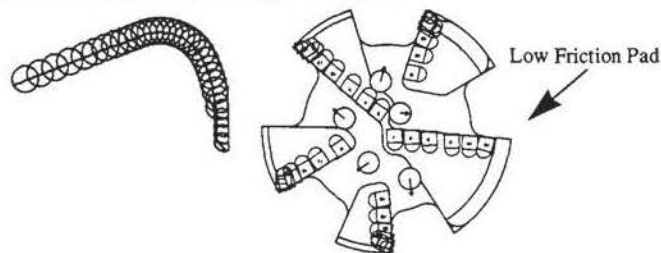


Figure 15 - Cutter layout and profile of the 12-1/4 in. Anti-Whirl PDC bit used on West Delta 103 No. 6.

Hard sections are usually best drilled by reducing the rotary speed and increasing the applied bit weight. It is important to remember that bits are more susceptible to whirl in the harder sections where the rock is competent enough to damage the cutters.

Whirl Reducing Features

Previous testing has shown that the use of stabilization above the bit face is insufficient to prevent downhole bit whirl². The use of a radial bit imbalance force (low friction Anti-Whirl bit) to reduce the tendency for downhole whirl is considered the best by the authors since the technology incorporates a restoration force on the bit face to maintain bit stability. There are whirl reducing features that can be used to complement the stability of an Anti-Whirl bit design, but they are considered insufficient by themselves. This point is impor-

tant because whirl reducing features can be misinterpreted to imply that they incorporate the Anti-Whirl design concepts.

Another concern is the variation between manufacturers in their approach to incorporate the Anti-Whirl technology. Diversity is good, but it can also leave a sour taste after a poor bit run. Anti-whirl bit designs that have been qualified through laboratory and field testing reduce the risk of this happening.

Below is a summary of various whirl reducing features with their benefits and limitations.

Backrake on Peripheral Cutters and Gauge Trimmers

Increasing the effective backrake on the gauge trimmers puts more of the diamond into compression making the cutter less susceptible to chipping of the carbide backup and spalling of the diamond table. The term "effective" is used to define the orientation of the cutter with respect to the rock and not the axes plane of the bit. Increased backrake also reduces both the aggressiveness of the cutter and its tendency to cut into the borehole wall. Tighter wall clearances reduce the tendency for bit whirl and allow the cutters on the bit face to cut more efficiently.

Siderake on Peripheral Cutters and Gauge Trimmers

Increasing the siderake on the outer cutters also puts more of the diamond table into compression as the cutter follows a downward spiral path. Peripheral cutters and gauge trimmers set with zero siderake experience high contact stresses on the leading edge making them more prone to chipping, especially when the bit contacts the bore hole wall or bottomhole profile during a lateral impact.

Cutter Aggressiveness

In the machining industry, an aggressive cutter will sometimes chatter resulting in reduced life. One method of extending cutter life and improving performance is to decrease the cutter aggressiveness. This is accomplished by increasing the cutter backrake.

New PDC cutters are "sharp" since most of the load is applied directly to the diamond table with negligible loading on the carbide backup. The sharp edge creates high contact stresses which allows the cutter to be more easily chipped and damaged. Chamfering the edge of the diamond table increases the diamond contact area and also puts more of the diamond in compression rather than shear. This reduces the tendency to spall the diamond table or chip the cutter. The downside of using chamfered cutters is that in a firmer formation, the applied bit weight will need to be about 50% more for comparable bit performance. Normal diamond wear gradually removes the chamfer effects resulting in negligible difference between a chamfered and an unchamfered cutter.

Table 5

Backrake (θ , deg.)	Vertical Force (lbs)	Normalized Force F_{10}/F_{θ}	Ratio $\sin(10)/\sin(\theta)$
-10	220	1.0	1.0
-20	400	1.8	1.8
-30	620	2.8	2.8
-40	875	4.0	4.0

Another way of reducing the "sharpness" is to increase the cutter backrake angle. Higher backrake reduces the tendency of the bit to "grab" the rock and initiate whirl, but at the expense of rate of penetration. Higher backrake also makes the cutter less susceptible to chipping when drilling firmer rock since more of the cutter is in compression than shear. The downside is that for con-

stant rates of penetration, the use of higher backrake requires increased applied bit weight.

The data in Table 5 was collected at the University of Tulsa on their single cutter test machine. Unchamfered PDC cutters were used to cut Carthage limestone under a confining pressure of 1,200 psi. The data shows that for a constant depth of cut, the applied weight required to penetrate the rock increases linearly with increases in cutter backrake angle.

Cutter Profile

Bits with flat profiles are more stable than bits with highly tapered profiles because the center of rotation on a flat profile is less sensitive to lateral offsets. Cutter density is a problem with using flatter profiles since the area available for cutter placement is limited compared to a more tapered profile. Bit cleaning is another problem with flat profiles. In order to obtain higher cutter densities, the cutter layout is usually set on spirals which are more difficult to clean than bladed designs.

The use of a cone at the bit center also enhances stability since the cutters inside the cone react against any lateral bit displacements. The cutters inside the cone also tend to cause whirl in the opposite direction, negating some of the overall whirl tendency. As the cone angle increases however, steerability of the bit decreases and bit balling becomes more of a problem. There is also a possibility that a segmented lithology section could shear at the nose of the bit wedging rock inside the cone, essentially creating a bearing on bottom.

Stability Grooves

Stability grooves are another way to increase stability². With this approach, one or more rings of cutters are incorporated on the bit face to generate deep grooves in the rock bottomhole pattern. Any lateral bit displacement is counteracted by cutters on the opposite side which are inside the grooves. This approach is similar to the use of a deep cone in that the resistive force is generated by lateral displacement of the bit. Laboratory testing has shown that the grooves do not offer the range of stability provided by the low friction gauge concept.

Force Balancing

Previous testing has shown that lowering the lateral force imbalance can reduce the whirl tendency.⁹ Since that time, in house measurements and analysis of over a 100 PDC bit designs from different manufacturers showed that the calculated bit imbalances averaged 5-15%, with some as high as 30%.

Besides the difficulty in building a bit with less than 5% imbalance, there is still no force to resist whirl, and once it starts, it is difficult to stop. Force balanced bits can be stable, but only within a very narrow operating window.

Summary

Anti-whirl PDC bit designs were run successfully by Amoco drilling engineers in many parts of the world. The applications included straight holes with rotary and motor assemblies and with steerable systems. Significant savings were realized through proper use of the Anti-Whirl technology. Whirl reducing features were reviewed that are beneficial in reducing whirl and complementing the Anti-Whirl technology, but are considered insufficient by themselves to prevent whirl.

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