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To cite this article: Xiaoning Zhang *et al* 2019 *IOP Conf. Ser.: Earth Environ. Sci.* **300** 022029

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Increasing drilling speed in long horizontal intervals in Aktobe Kazakhstan

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Abstract. The Aktobe project is at the east margin of the Pre-Caspian Basin, where horizontal well is mainly used to develop the low porosity and permeability layers. To improve production per well, the horizontal interval increased from $\pm 400\text{m}$ to $+1000\text{m}$. Due to complicated geological structure, variable boundary and thickness of target layers, the RSS was employed to improve the rate in layer. But the average ROP was just 2.36m/hr , and average footage was just 335m per bit due to high strength of the formation. To solve this problem, the wearing characteristic of PDC bits was analyzed. The BHA and table rotary speed were optimized on the basis of drilling pipe vibrating calculation. Thus, the drilling technology for hard and long horizontal interval, including high performance PDC bit, RSS, PDM, BHA with $1/2$ stabilizer, has been worked out. The technology was used in 5 wells, of which 4 wells at 60 rpm , had stick-slip index of less than 80% , the drill bits out of the wells had few cutters broken by vibrating; 1 well had stick-slip index of higher than 80% at $70\text{--}80\text{rpm}$, and the drill bits out of the well had many cutters broken by vibrating. Compared with Well H814, the horizontal section drilling time shortened from 22.5d to 9.6d , by 57.7% , ROP increased by 261.4% , and the footage increased by 195.5% . The optimized horizontal drilling technology for hard formation could provide reference for the drilling of similar hard formation, especially for the other oilfields in the Pre-Caspian Basin.

1. Introduction

The North Tluwa Oilfield and Zhanazhol Oilfield in Aktobe of Kazakhstan mainly have low-porosity and low-permeability carbonate reservoirs. The carbonate rocks are dominated by dolomite with the uniaxial compressive strength of $103\text{--}186\text{ MPa}$. The interbedded shale has a uniaxial compressive strength of $14\text{--}41\text{ MPa}$ [1]–[4]. Before 2015, PDM combined with high-performance PDC bits from Chuanshi, National Oilwell Varco and Schlumberger MDI series were applied[5], resulting in the average ROP of 1.92m/h and the average footage about 302m in drilling the 149.2mm horizontal wellbore. In 2016, the RSS with the Schlumberger Stinger PDC bit was employed, with the average ROP of 2.36m/h and the average footage of 335m for the 215.9mm horizontal wellbore [4]. To further improve the ROP and the drill footage, and shorten the drilling cycle and reduce drilling cost, the causes of the bit wear were analyzed. The theory of the drill string mechanics was used to qualitatively analyze the downhole vibration, and then optimize the BHA and RPM of rotary table. The study results were used in five wells, achieving remarkable outcomes. Compared with the drilling indexes of Well H814, the drilling cycle was shortened by 57.7% for the similar length of the horizontal section.



2. Horizontal well drilling status

2.1. Problems in horizontal section drilling

In 2013-2015, 35 horizontal wells were completed in the North Tluwa Oilfield and Zhanazhol Oilfield, with an average horizontal section length of 432 m. The steering was mainly conducted by conventional PDM with LWD. The wells were completed by 149.2 mm openhole, and then fractured at multiple stages with oil swellable packer and sliding sleeve. Due to the single-bend PDM and conventional geosteering tools, the average payzone drilling rate of North Tluwa Oilfield was only 38%, and the average production per well was only 56t/d. The average ROP was only 1.91m/h, the average footage was 302m, and the average drilling cycle of the horizontal sections was 17 days.

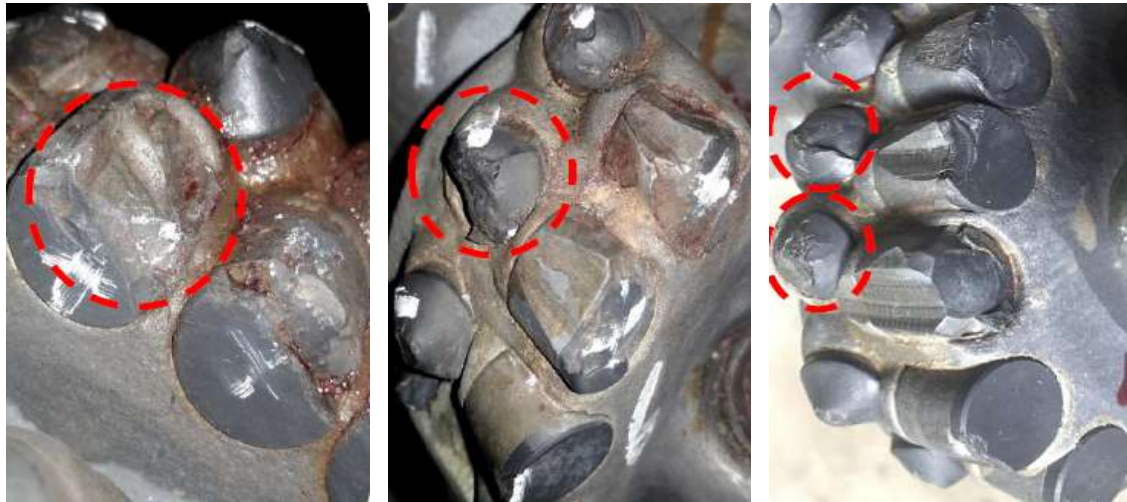
In 2016, to improve the development effect, the horizontal section was extended to over 1000m. The wells were completed with 139mm casing and then multistage acid fracturing. The Periscope RSS was used to improve the reservoir drilling rate. To increase the ROP, Schlumberger's Stinger PDC bit was used. The technologies were applied in Well H814 with the horizontal section length of 1004m. The drilling ended in 22.7 days, with an average footage of 335m, average ROP of 2.36m/h, a reservoir drilling rate increase to 83.9%, and an output increase of 10 times[6]. Compared with the performance of PDC with conventional LWD and PDM drilling tools, the Stinger bit combined with the Periscope RSS has improved the reservoir drilling rate greatly, and the index of drilling cycle and the drill bit to some extent. During the drilling of this well, due to the low ROP, two bit-change tripping were conducted to finish the 1004m horizontal section (three drill bits were used). The drilling parameters of the three drill bits are shown in Table 1. During drilling, discontinuous stops of the rotary table were observed, indicating severe downhole vibrations. The consequent severely broken PDC bit (as shown in Figure 1) resulted in poor cutting performance, which was the main reason for the low ROP. However, due to the high cost of the Periscope RSS tool, it is necessary to increase the ROP and shorten the drilling cycle of the horizontal section to reduce drilling costs.

2.2. Reasons of cutter broken

Stinger conical bit is a PDC bit introduced by Smith Bit Co., Ltd. in 2014. It has an ultra-thick synthetic diamond layer with higher impact resistance, high heat dissipation and high wear resistance. The robust and more effective cutter reduce the bit torque by 26% as the ROP increases, resulting in better directional drilling response and smoother tool surface control, which has improved bit stability and reduced impact and vibration of the downhole tool[6]. Since the uniaxial compressive strength of dolomite is 103-186 MPa[1]-[4], Z516 and Z616 were proposed for the formation. The breaking of PDC bit cutters is mainly caused by downhole vibration. When drilling in hard formation, axial, lateral and torsional vibrations are likely to occur, and the stick-slip vibration is a kind of torsional vibration [7]. Through statistics on a large number of measured data, the stick-slip vibration accounts for 40%-50% of the total drilling time in the oil industry worldwide[2]. The RPM of the drill bit is 3-7 times of the rotary table during slip. The stick and slip period is 2-10s. The high-speed rotation in the slip stage has a great influence on the life of the drill bit and the downhole tool[2]. If not properly controlled, the stick-slip vibration can cause axial and lateral vibration[4]. There are many factors that cause the stick-slip vibration in the well, but two of them are the main reasons. In the drilling of vertical wells and low inclination wells, the interaction between the drill bit and the formation is the main cause of stick-slip vibration, while in drilling the horizontal well and the extended reach well, the interaction between the drill string and the formation is the main cause[3]. During drilling the horizontal section of Well H814, high RPM was adopted. The interaction between the drill string and the formation was likely to cause stick-slip vibration, which accelerated the impact damage of the bit cutter, shortened the life of the drill bit, and lowered the drilling efficiency.

Table 1. Drilling parameters of horizontal section of Well H814

Spud	Well Depth /m	Footage /m	ROP/(m·s ⁻¹)	Drilling Parameters		
				WOB/t	RPM/(r·min ⁻¹)	Flow Rate /(L·s ⁻¹)
First	2540~3004	461	2.55	10	100	32
Second	3004~3170	166	1.47	10	100	32
Third	3170~3453	373	2.82	10	100	32

**Figure 1.** Photos of the three used PDC bit in drilling the horizontal section of Well H814

3. Technical measures

With the deepening of understanding on stick-slip vibration, it is realized that the stick-slip vibration cannot be completely eliminated by a single method, and a comprehensive method is needed to address the problem. The comprehensive solution to the stick-slip vibration mainly includes five aspects: optimization design of PDC drill bit, BHA and drilling parameters; usage of wellhead compensation system (such as STRS), and downhole damping tool (torque impactor)[7]-[18]. The PDC bit needs to be designed specially with the help of drill bit supplier, which may need several rounds of improvement. The wellhead compensation device and downhole damping tool need to be purchased and transported, which takes quite some time. Therefore, the easiest way on site is to optimize the design of BHA and drilling parameters. Since the downhole vibration is difficult to accurately predict, in order to provide an optimization basis for the BHA and drilling parameters, the drill string vibration module in Landmark software was used to analyze the influence of the BHA and drilling parameters on the downhole vibration.

3.1. BHA optimization

Qualitative analyses were conducted based on the casing program, well trajectory, BHA and drilling fluid performance in reference[6]. The effects of three commonly used BHAs on downhole vibration were examined. The main differences of the BHAs are the installation position and number of the stabilizer: 1# BHA, no stabilizer, BHA used in [6]; 2# BHA, one stabilizer 212.7mm in diameter installed 4.09m from the drill bit behind the RSS on the basis of 1# BHA; 3# BHA, two stabilizers, a 209.55mm stabilizer is installed behind the LWD 21.41m from the first stabilizer in the 2# BHA.

The drilling parameters used in calculation were: 100 rpm (rotary table), 10 t WOB, and the 30 l/s flow rate. The calculation results of axial force, shear force, torque, flow rate and momentum calculation are shown in Table 2.

The axial force of the three types of BHAs is almost the same. The axial force of the double stabilizer BHA is only 1.06 times that of the non-stabilizer BHA. After adding the near bit stabilizer, the shear stress is greatly reduced to 0.53-0.56 of the non-stabilizer BHA. With the double stabilizer BHA, the shear stress is further reduced to about 0.52-0.55 of the non-stabilizer BHA. The shear force of the single and double stabilizer BHA have little difference. The double stabilizer BHA has the maximum torque, about 1.10 times that of the non-stabilizer BHA. By adding the near-bit stabilizer, the maximum displacement is reduced to 2.54mm, which is 0.52-0.90 of the original. The second stabilizer in the double stabilizer BHA has little influence on the displacement. By adding the stabilizer, the axial momentum and the lateral momentum are greatly reduced. However, the axial momentum of the single stabilizer BHA and the double stabilizer BHA are almost the same, about 0.50 of the non-stabilizer BHA. The lateral momentum of the single stabilizer BHA is 0.34 of the non-stabilizer BHA, and the lateral momentum of double stabilizer BHA is 0.27 time that of the non-stabilizer BHA.

Therefore, the single stabilizer BHA and the double stabilizer BHA have small increase in torque and axial force, but several other technical indexes reduced to around 0.5 that of the non-stabilizer BHA, and the lateral momentum reducing to 0.27 of the non-stabilizer BHA. This is mainly because the use of the stabilizer limits the vibration displacement of the drill string near the bit and limits the influence of the drill string vibration on the bit vibration. Therefore, the single near-bit stabilizer BHA and the double stabilizer BHA are recommended.

Table 2. Effect of BHAs on downhole vibration

BHA	Axial Force (kN)	Shear Force (N)		Torque (N.m)	Displacement(m)			Momentum(N.m)	
		Axial	Lateral		Axial	Tangential	Lateral	Axial	Lateral
1#, non-stabilizer	24.5	1787	1756	314	2.82	3.43	4.84	278	358
2#, single-stabilizer	24.8	1000	934	322	2.54	2.54	2.54	139	123
3#, double-stabilizer	25.4	934	916	346	2.54	2.54	2.54	139	95

3.2. Optimization of rotary table RPM

The bit RPM and WOB are the two main factors affecting the ROP. If the WOB is too low, there is no way to increase it. But the bit RPM, which is mainly controlled by the downhole power tool and the rotary table, can be optimized by optimizing rotary table RPM and selecting proper power tool, so as to ensure efficient work of drill bit. Therefore, the influence of RPM of rotary table on the downhole vibration was qualitatively analyzed next. Based on the 3# BHA with double stabilizer, under the WOB of 10t and considering the wellbore cleaning, the influence of the rotary table RPM of 60, 80, 100rpm on the downhole vibration was mainly simulated. The calculation results are shown in Table 3.

Since the BHA has a near-bit stabilizer, the displacement near the drill bit is limited, but the rotary table RPM has no effect on the displacement. However, the rotary table RPM has a great influence on the axial force, shear force, torque and momentum. When rotary table RPM increases from 60 rpm to 100 rpm, axial force increases by 0.4 times, axial shear force increases by 1.6 times, lateral shear force by 0.6 times, torque 0.5 times, axial momentum 0.8 times, and lateral momentum reduces to 0.6 times.

Overall, the higher the rotary table RPM, the more severe the downhole vibration. However, considering the requirement of cutting carrying, the rotary table RPM cannot be too low. Therefore, the rotary table RPM was reduced from the original 100 rpm to about 60 rpm, which could control the downhole string vibration and reduce the influence of the drill string on the drill bit. To keep the drill bit with sufficient energy to break the rock, the downhole PDM was used to increase the RPM to 150 rpm during the drilling process.

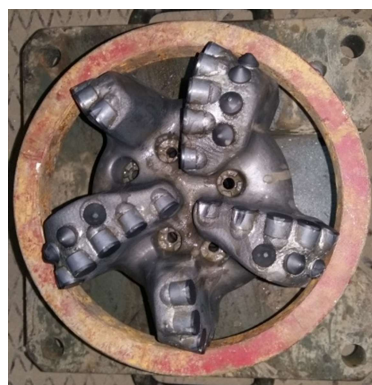
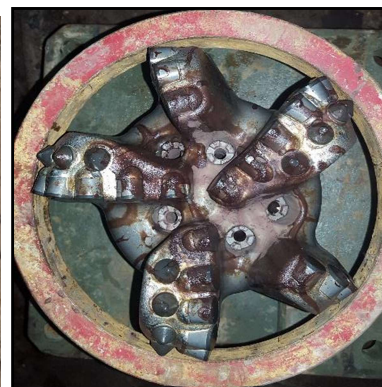
Table 3. Effect of rotary table RPM on downhole vibration

Rotary Table RPM(rpm)	Axial Force (kN)	Shear Force (N)		Torque (N.m)	Displacement(m)			Momentum(N.m)	
		Axial	Lateral		Axial	Tangential	Lateral	Axial	Lateral
60	17.8	366	558	226	2.54	2.54	2.54	77	141
80	21.4	545	632	283	2.54	2.54	2.54	83	104
100	25.4	934	916	346	2.54	2.54	2.54	140	95

4. Field application

Table 4. Main drilling parameters of horizontal sections of the 5 wells

Well Name	Drilling Completion Time	Well Section/ (m)	Horizontal Section Length / (m)	Horizontal Section drilling time/ (d)	Flow Rate/ (l·s-1)	Rotary Table RPM/ (rpm)	ROP / (m·h-1)	Stick-Slip Index
H844	2017/3/28	2588-3795	1207	13.0	29-31	60	7.49	60%-80%
H817	2017/5/1	2531-3261	730	5.8	29-31	60	10.34	
H2610	2017/8/13	3926-4930	1004	12.0	35	60	6.46	
H842	2017/9/15	2617-3617	1000	6.2	29-31	60	9.06	
H7205	2017/5/23	3544-4569	1025	11.0	30-31	70-80	12.12	80%-100%
Average			993	9.6			8.53	

**H2711****H817****H7205****Figure 2.** Photos of the used PDC bits

In 2017, the previous drilling technology with reduced rotary table RPM, double stabilizer and downhole power tool was applied in five wells and the drilling data is shown in Table 4. To verify the downhole vibration control, the downhole vibration measurement sensor was installed in the downhole measurement joint. The measured data was transmitted to the ground and processed by software[19]-[20]. The stick-slip index was used to characterize the severity of the downhole vibration, and the drilling was adjusted according to real-time data[13]. According to relevant research, the stick-slip index of less than 40% indicates the downhole vibration is not severe, and drilling can continue. If the stick-slip index is 40%-80%, the WOB and RPM can be adjusted according to the situation. When the stick-slip index is above 80%, drilling must be stopped and the WOB and RPM be adjusted [13]-[18]. Four wells out of the five with the RPM of 60 rpm had stick-slip index of 60%-80%. That means although the down stick-slip index remained at a high level, the downhole vibrations were effectively controlled and drilling could continue. The photos of the bits after ROH show that the damages of PDC cutters are mainly wear. Only a small number of cutters are broken. In the Well H7205 where rotary table RPM was 70-80 rpm, although the ROP reached 12.12 m/hr, the measured stick-slip index was up to 80%-100%, and the broken cutters at the core of the bit significantly increased. In addition, signal failure of MWD was

observed once, and additional tripping was made to change the MWD tool, resulting in horizontal section drilling time of 12.2 days. In contrast, the horizontal section of Well H842 and Well H817 were drilled in one trip in only 5.8-6.2 days, with an average ROP of 9.06-10.34m/h. Well H844, H2610, H7205 had an additional trip for damaged PDM and signal failure of MWD, so horizontal section drilling time increased to 11-13 days, but each used only one PDC bit to finish the horizontal section with the average ROP of 6.46-12.12m/h. The five wells had an average drilling footage of 993m, the drilling cycle of the horizontal section of 9.6 days, and the average ROP of 8.53m/h. Compared with the drilling indexes of Well H814, the drilling cycle of the horizontal section was shortened by 57.7%, and the average ROP increased by 261.4%.

The actual drilling data also proves the correctness of the BHA and the rotary table RPM optimization. In the later drilling operation, to avoid the accelerated damage of the PDC bit or the failure of the downhole instrument, it is proposed to control the rotary table RPM at 60 rpm and adopt long-life PDM and refined field operation rules to ensure one trip drilling of the horizontal section.

5. Conclusion

(1) Under the calculation conditions in this study, the calculation results of axial force, shear force, torque, displacement and momentum of the three types of BHAs with non-stabilizer, single near-bit stabilizer and double stabilizer indicate that, compared with the BHA without stabilizer, the other two BHAs have a 0.5 times parameters values and 0.27 times lateral momentum except for a small increase in axial force and torque (1.06-1.10 times of the former one).

(2) On the basis of the previous drilling technology, by reducing the rotary table RPM to 60 rpm and using the double stabilizer BHA and PDM, the downhole vibration was effectively controlled, with the stick-slip index of less than 80%. The drill bit damages were mainly wear and few cutters were broken. The drill bit life was significantly prolonged that the 730-1207m horizontal section was drilled in one trip. Compared with the drilling indexes of the Well H814, the drilling indexes of the other wells were greatly improved, with the average ROP increasing by 261.4%, the average footage increasing by 195.5% and the horizontal section drilling period shortening by 57.7%.

(3) In difficult-to-drill formations, drilling difficulties may not be completely addressed only by using advanced tools and drill bits. Optimization of drilling parameters is also a necessity to greatly improve drilling efficiency. In the future, PDC bit cutter layout, PDM parameters, dimensions and parameters of the stabilizer, and placement of the HWDP on the entire drillstring should be analyzed to further control the downhole vibration; and long-life PDM and refined field operation rules should be adopted to ensure one trip drilling of the horizontal section.

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