Norwegian operators reap rewards by controlling inclination in rotary mode

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CHANGING THE DESIGN of bottom-hole assemblies to incorporate an adjustable stabiliser has meant that Norwegian operators are reducing bottom line costs while improving hole quality. This editorial reviews this technology and examines horizontal drilling applications within 9 Statfjord wells.

Long before rotary steerable systems became fashionable, and as far back as 1986, **Andergauge** extolled the virtues of "2D" rotary steering with adjustable stabilisers in conventional rotary assemblies. Operators who sought the benefits of rotary drilling found that they could do so by using an adjustable stabiliser. Operators could control wellbore inclination, over tangent and drop off sections, without the need to trip for BHA modifications.

Directional drillers were keen to use such assemblies because they provided an unprecedented ease and flexibility in wellbore inclination control. In response to changes in formation conditions the driller—by following a simple setting procedure—could adjust the BHA downhole and thus control inclination. Consequently, it became possible for a BHA with an adjustable stabiliser to drill to TD in a single run. Fewer trips meant that the technology rapidly added value to the drilling process, and adjustable stabilisers very quickly proved their reliability and cost effectiveness.

Figure 1: Statfjord horizontal section

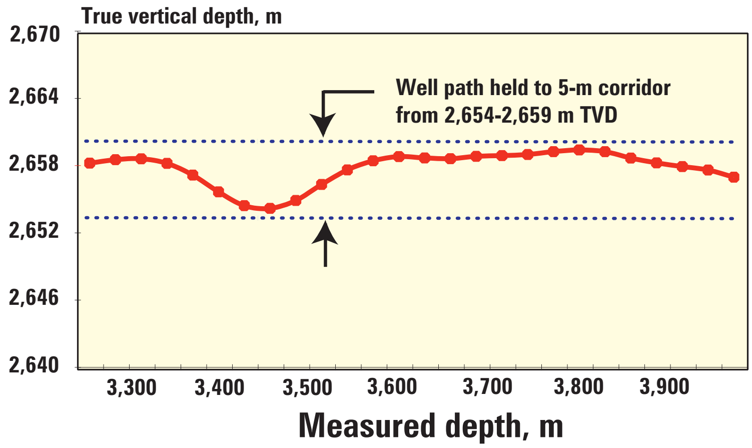
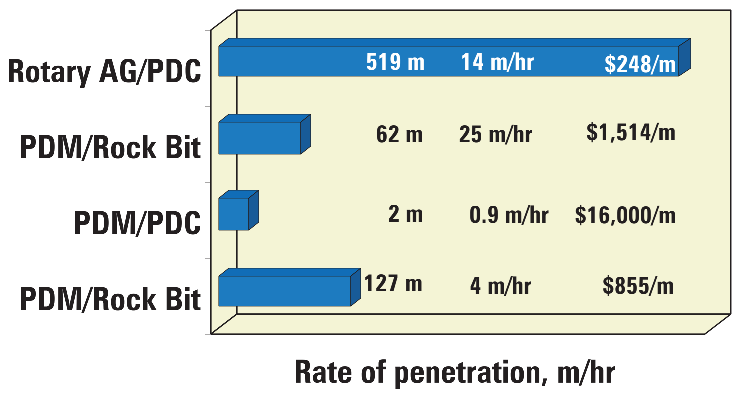


Figure 2: ROPs from a Statfjord well



Lateral thinking led to the transfer of these benefits to horizontal drilling (**Chaffin**, 1991). The validity of this approach has been clearly illustrated, as adjustable stabilisers fit the requirements of horizontal drilling perfectly, providing rapid responses that enable precise inclination control within tight TVD target corridors. As azimuth corrections are unlikely within 90%* of horizontal sections, the technology can often drill straight to TD. In the few cases where azimuth corrections are anticipated, an adjustable stabiliser can be placed above a motor to eliminate any sliding for inclination control, thereby maximising ROP.

STATFJORD OFFSET DATA

One of the most important methods of predicting BHA behaviour is through offset data. An extensive database allows past well records to be pinpointed and analysed. Once established, the key determinants of BHA behaviour—bit walk tendencies, formation changes, bedding, dip angles—can be characterised to calculate the likely change in dog-leg severity between alternate tool settings. This lends greater certainty to the process of inclination control, because the offset data from past wells is used to select optimal BHAs for future wells.

In the Statfjord field, 9 horizontal wells have been drilled over the past year using the Andergauge 2-dimensional rotary steerable system. Significant problems encountered whilst attempting to slide-oriented motors led to the introduction of the adjustable stabiliser, in a near bit rotary configuration. In all 9 wells, the rotary BHA has consistently

* Independent research has consistently shown that in tangent sections over 90% of slide drilling are for inclination control only.

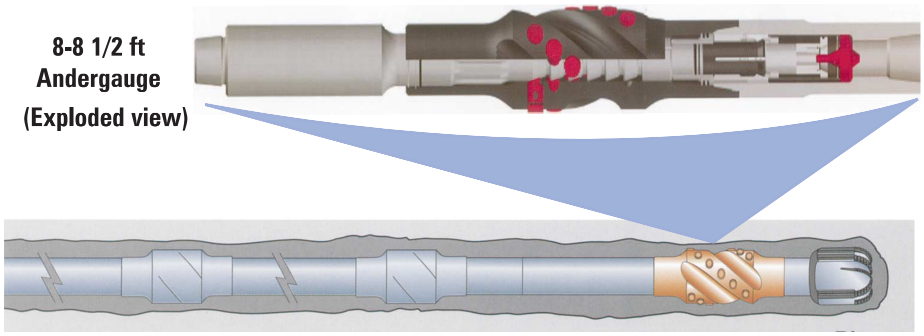
placed the wellbore within a tight target corridor.

Figure 1 shows the horizontal well section for a typical Statfjord well illustrating the TVD corridor that was maintained.

Table 1 summarises BHA performance over all 9 wells and provides examples of how footage drilled in the payzone can be maximised by adjustable stabiliser drilling.

This illustrates the consistency of performance realised from the 2-D rotary assemblies and the tight TVD maintenance achieved through predictable BHA responses. However, Table 1 does not show the unseen benefits which have become synonymous with adjustable stabiliser controlled BHA's.

Figure 3: Typical Stafjord BHA



UNSEEN BENEFITS

Horizontal wells had traditionally been drilled using conventional steerable assemblies. However, it is known that this methodology has several limitations that can complicate and slow down the drilling process. These limitations include the difficulty of setting and maintaining tool face due to the effects of weight stacking and reactive torque; poor hole cleaning and the formation of cuttings beds caused by non-rotation; an increase in the frequency and length of intervals that are drilled while sliding high or low side to control inclination.

These 3 limitations can be drawn

Table 1: BHA performance in 9 Statfjord wells

Well Number	Reservoir section, m	Full gauge, °/30 m	Under gauge, °/30 m	TVD tolerance achieved, m (±)
1	700	+0.8	-1.98	5
2	203	+0.6	-0.8	4
3	566	+1.0	-0.8	3
4	404	+0.8	-1.0	5
5	203	+0.6	-0.8	5
6	276	+0.4	-0.8	4
7	297	+0.5	-0.5	4
8	279	+1.0	-0.5	3
9	479	+1.0	-0.5	3
Average	**378**	**+0.7**	**-0.8**	**4**

together to form a powerful argument: Sliding for inclination control should not be an option.

SLIDING

Operators or directional drilling companies may not be able to find the time to analyse slide data. Consequently the unnecessary costs of low rates of penetration and the time spent sliding for inclination control per section may go unrecognised. A chance to save money is missed.

On other occasions, sections may simply be classified as "good" and filed away. These sections usually refer to a lack of equipment failure or high rates of penetration with minimal sliding. However, so-called "good" sections often hide the significant time and costs of sliding for inclination control. Additionally, there is a tendency for not logging attempts to orient tool face.

Often, when a slide analysis is conducted, sliding is expressed as a percentage of total section distance. This can create the misconception that a relatively short length of sliding is involved, which is then labelled as "minimal sliding". Typically, analysis of "minimal sliding", reveals sizeable hidden costs. Crucially, though, these costs are preventable.

HIDDEN COSTS OF DOG LEGS

Well-path corrections made by sliding create instantaneous dog legs and result in tortuous wellbores. The implications of this continue far beyond the well-construction stage. They may remain throughout the entire lifecycle of the well. As a general rule, any well with high dog legs will generate high wall contact forces, which in turn may necessitate the use of torque reduction devices such as time-consuming non-rotating drill pipe protectors or expensive drilling fluids.

In some cases, increased output top-drive systems may be required. High dog legs can also cause incorrect centralisation of casing in the hole, leading to poor cementing. High dog legs may also induce premature casing wear. This is because hole tortuosity makes it harder for casing, liners, production tubing to pass through the wellbore without damaging the wellbore or tubulars. In the long run, lifting costs may rise further, due to increased work-over operations and interrupted production.

In comparison to sliding, not only does drilling with an adjustable rotary assembly lead to superior wellbores, it also increases penetration rates. Figure 2 shows typical ROPs that were achieved in the Statfjord field.

QUALITY WELLBORES

Wellbore quality is enhanced because instantaneous dog legs are eliminated. As a result, hole tortuosity is reduced and the well profile is improved. This is because rotary build and drop trends take time to break, and therefore, dog legs are smoothed out over long sections. Consequently, casing can be set more easily and there is reduced potential for workovers and interrupted production. Constant rotation means that cuttings are more likely to be agitated and circulated out. This results in better hole cleaning.

Mclellan, **Hough**, et al, (1998) list further benefits of rotary adjustable stabiliser drilling as "continuous cuttings disturbance, reduced potential for mechanical and differential sticking, adverse vibration and back reaming".

CONCLUSION

The Andergauge adjustable stabiliser was first introduced in 1986 and has been successfully used to control inclination over 4,500 intervals. At least 500 of these 2-dimensional applications have been successful horizontal runs similar to the cited Statfjord wells. This conclusively dispels the erroneous perception that a weight set tool cannot work past 90°. 2 major factors need to be considered by the innovative drilling engineer:

• If there is sufficient weight to drill ahead, then there is sufficient weight to cycle an adjustable stabiliser;

• In the majority of tangent sections of well paths, 2-dimensional inclination control is all that is required. This being the case, an adjustable stabiliser is hard (if not impossible) to beat.

Today's advocates of "fit for purpose" drilling tools have found that the adjustable stabiliser meets the criterion well (**Mims**, 1999). The adjustable stabilisers' cost effectiveness and reliability in 2-dimensional rotary steering, continue to make it a valuable directional drilling tool that can sit comfortably on the directional driller's shelf, along with the latest rotary closed-loop steerable systems.

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