

## High-Density Survey Data

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### Abstract

Current survey tools can provide much more than just inclination, azimuth and toolface. Survey tools enhanced with digital electronics, modern processors and high-accuracy sensors produce higher quality data and open the door to new solutions affecting many disciplines in relation to what is known as “wellbore quality”. Continuous inclination while drilling and continuous azimuth while drilling are used to reduce off bottom time.

High-density survey data can be used to analyze wellbore tortuosity in a section of the well or the well as a whole. Continuous casing data can show if the casing was set in compression or tension, identify the best location for electrical submersible pumps (ESP), and more accurately calculate sucker rod side forces. Additionally, high-density data reduces true vertical depth (TVD) uncertainty as well as lateral uncertainty, which can be used to improve reservoir maps. Finally, continuous information can be used to improve torque and drag simulations, drilling systems selection and bottom hole assemble (BHA) designs.

This paper presents a series of case studies demonstrating how high-definition survey data bring value to the different disciplines from drilling to completion and production.

### Introduction

The utilization of high-density survey data acquired during the drilling operation or logging runs adds significant value and efficiencies to the operators over the life of the well. New survey measurements are becoming available as the downhole MWD electronics are being upgraded. These upgrades include faster and higher resolution microprocessors that operate with lower power consumption enabling higher definition survey. True survey measurements are being made in a very dynamic environment while drilling, rotating or sliding, in addition to the conventional survey taken in a static “pumps-off” environment (Lowdon 2015). The survey measurements currently acquired while drilling provide a good picture of the real-time trajectory, but they will not be as accurate as static survey measurements. Today, static pumps-off surveys are taken every stand or 93 ft. This creates a gap in the knowledge of the borehole path (Stockhausen 2003). This can become critical during steering operations with mud motors or rotatory steerable tools. For example, in the event that the achieved build rate is too large, the gap between stationary surveys can result in the TVD at the end of a drilled section being above

the planned depth. Conversely, if the required build rate is not achieved, the TVD at the end of the section will be below the planned depth. The use of continuous inclination and azimuth enables the wellbore to be drilled closer to plan than ever before (Naveed 2016). It provides a view while drilling of the progress being made with the build and turn of the well without stopping to take a conventional static survey.

High-definition survey data sampled at high speed during logging or tripping operations provide valuable information that can be used throughout the life of the well (Ledroz 2017). At the end of each bit run, high-definition surveys can be taken while tripping out of the hole and subsequently used to update the wellbore tortuosity allowing improved torque and drag simulations (Gaynor 2002). The knowledge gained by updating the wellbore drilling models with actual measurements can be used to optimize the drilling equipment and configuration as well as the drilling plan in the next section of the well or further wells to be drilling from the same pad. During logging operations, high-definition survey tools can be deployed to log in and out of the tubing or casing. Often, the survey tools are run with other logging tools like a cement bond log or casing collar locator to improve logging efficiencies and reduce time. The survey data can be processed and used to generate a 3D tubular representation of the tubing or casing (Bang 2016). The 3D plot generated provides a picture of the tubular curvature, shape, and features that can be used to identify if the tubular is in compression or tension. In addition, the 3D log identifies straight sections that are long enough to house an ESP to improve its life and minimize downtime and repair costs. If a beam pump with sucker rods is used, the same high-definition survey data can be used to estimate sucker rod side forces and identify where the sucker rod guide sleeves should be placed to reduce friction and wear on the tubing and rod.

The surveying environment dictates the type of measurements that can be used. In the drilling environment, an open hole with sufficient non-magnetic collar spacing provided in the BHA, the traditional directional tool using a sensor package with three accelerometers and three magnetometers can be used to provide some of the measurements discussed. Alternative, if the BHA has a gyro while drilling tool, the gyroscopic information can be utilized for the continuous data, either while drilling or when pulling out of the hole. On the other hand, if surveying inside of casing, drill pipe or production tubing, an all-attitude continuous gyro tool using a sensor package with three accelerometers and three gyros must be used to provide the

measurements discussed above.

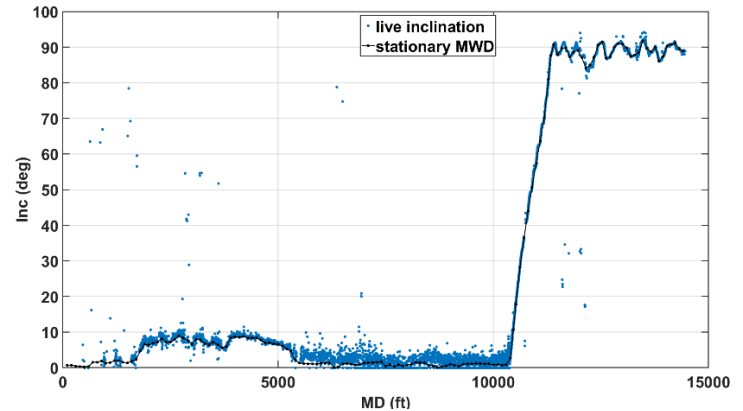
## High-Definition Survey Data during Drilling

Continuous surveys do not require any extra or new equipment since survey data at short intervals of depth can be generated from standard MWD directional sensor measurements. Whether sliding or rotating, it is possible to calculate continuous azimuth and inclination and transmit it to the surface with a relatively small effect on the transmission bandwidth. The accuracy of the inclination data depends on several factors including the rate of penetration (ROP), the actual inclination, data resolution and drilling vibration levels. Most companies providing continuous surveys are using the Z-axis accelerometer to calculate inclination and the Z-axis magnetometer to calculate azimuth.

### Continuous Inclination

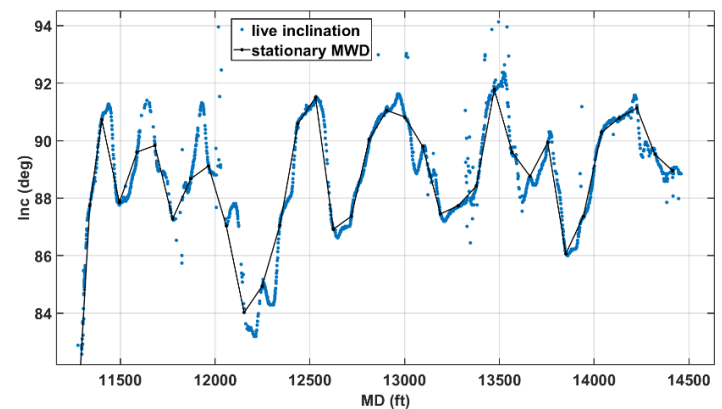
Continuous inclination provides immediate knowledge of build rates or drop rates in the wellbore without having to wait for the stationary survey. This additional inclination information allows the directional driller to optimize the slide time when using a mud motor. Drilling with a mud motor and changing between sliding and rotating creates a stair-step effect, which is known as the Stockhausen effect. This is well documented in Stockhausen's 2003 SPE paper. Typically, this is not seen with standard surveying intervals at approximately every 93 ft. The continuous inclination information can be used to better explain the increased open hole torque and drag experienced while drilling the curve than that predicted by the pre-job torque and drag model (Gaynor 2002).

Figure 1 is an example of continuous (live) inclination versus static inclination measured at every stand. Note from 0 to 10 degrees of inclination, the continuous data is somewhat noisy. This is due to the fact that the Z-accelerometer is aligned with the vertical component of the gravity field and small variations in inclination do not generate large changes in the Z accelerometer reading. Once over 10 degrees of inclination, the noise gradually reduces and the continuous inclination becomes very accurate at/near horizontal. High vibration levels generate the occasional outliers that can be easily ignored or filtered out. The data in the build and horizontal section of the well is fairly reliable and should be used to improve the drilling process in relation to ROP and to avoid prolonged sliding periods.



**Figure 1:** Stationary and high-definition inclination data for the whole well.

Figure 2 is a zoomed-in view of the lateral section. The continuous inclination correlates very well with the stationary data, but it has sporadic outliers. The continuous inclination also shows a higher degree of tortuosity in the wellbore when compared to the static surveys taken at every stand.



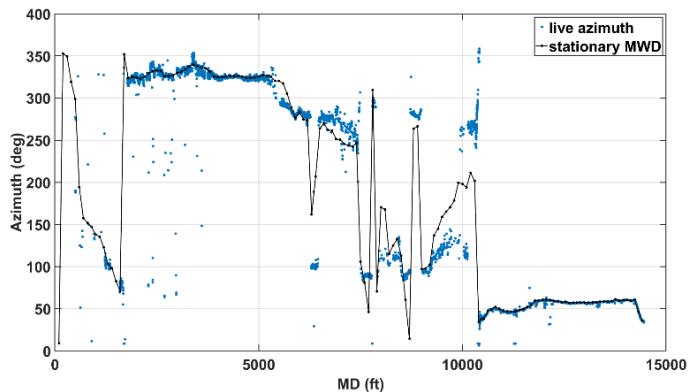
**Figure 2:** A zoomed-in view of the lateral section.

### Continuous Azimuth

Continuous azimuth provides knowledge of the borehole turns in real-time, without having to wait for the stationary surveys to show it. The additional azimuth data allows the directional driller to optimize the sliding time required to turn the well when a mud motor is used. While changes in downhole formation can push the wellbore away from the desired plan, the availability of continuous azimuth data allows the directional driller to identify this issue early and react much faster than just relying on traditional static surveys taken at every stand.

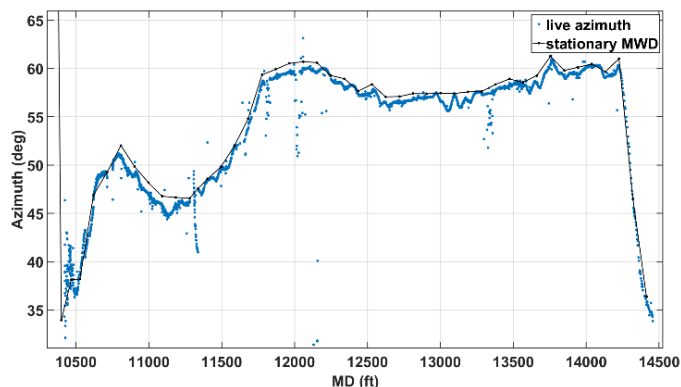
Figure 3 is an example of continuous azimuth versus static azimuth measured at every stand. The quality of the data is best when the tool is not aligned with magnetic north or magnetic south. When the Z-magnetometer is aligned with the magnetic field, it is not very sensitive to changes in directions; similar to the situation arising with the Z-accelerometer and the gravity vector previously discussed. Continuous azimuth

data have a higher number of outliers when vertical; as inclination gets higher, the number of outliers progressively reduces and tend to be minimized at horizontal.



**Figure 3:** Stationary and high-definition azimuth data for the whole well.

Figure 4 is a zoomed-in graph of the horizontal section of the well. There is a systematic error between continuous azimuth and static azimuth. This could be related to the algorithm used to estimate the azimuth or the fact that the stationary data was corrected for axial magnetic drillstring interference while the live azimuth was not corrected. Regardless of the difference between the two azimuths, the continuous azimuth provides very useful information regarding the detailed shape of the wellbore trajectory. In this particular example, the formation caused a change in the trajectory that resulted in an azimuth shift of 15 degrees over one stand length.

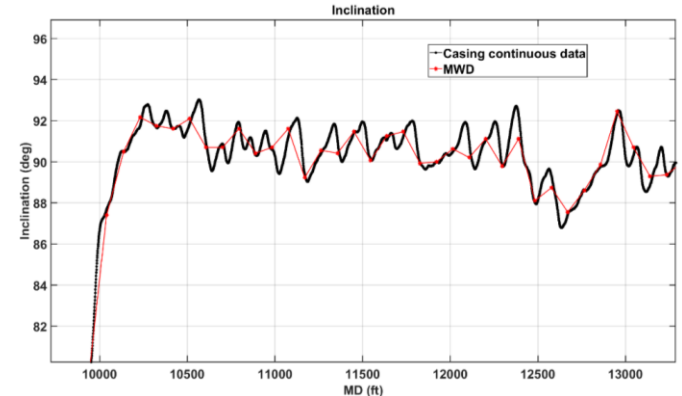


**Figure 4:** A zoomed-in graph of the horizontal section of the well.

### Reduction in TVD and Lateral Error

Large differences in TVD values between a high-definition survey and MWD surveys have been identified over the years (Stockhausen 2003). The main contributor to this difference seems to be the sliding/rotating drilling pattern and wide spaced stationary survey measurements typically at a pipestand or 93 ft apart. High-definition gyro surveys can

produce surveys with high depth resolution, even smaller than a one-foot interval.



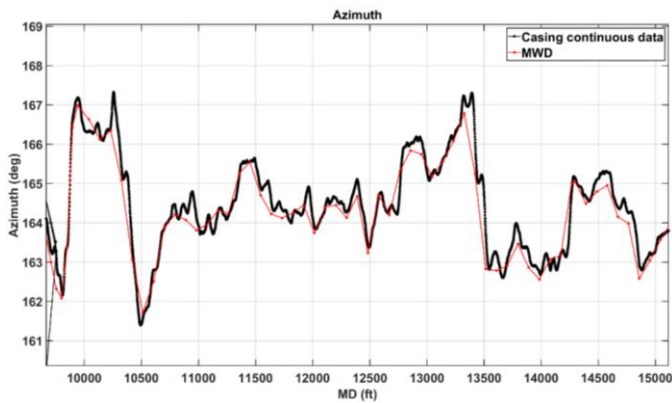
**Figure 5:** Stationary and high-definition inclination data that resulted in TVD differences.

Figure 5 shows an example of a casing survey and the MWD survey data. For this well, the TVD results at total depth (TD), 8,390 ft, produced a discrepancy of 18 ft between the MWD survey and high-definition gyro survey. Real-time and post run quality control tests on both tools indicated no problems. Also, the agreement between the stationary surveys and the continuous surveys is within the allowable values dictated by the tools error models. All this suggest that the large gaps in the stationary surveys are the source of the discrepancy.

The high-definition inclination plot shows that the gyro and MWD surveys match well at the points where MWD surveys were taken but the inclination between the stationary surveys can build and drop by up to 2 degrees.

As the MWD surveys would normally be taken at connections, the surveys will likely see the same point in the sliding/rotating pattern over a stand. This is dependent on sensor distance from the bit, but in this case, MWD surveys are at the lowest point in inclination every cycle. This leads not only to large TVD discrepancies but also gives the impression that the drilling pattern has produced very low doglegs and a very smooth profile. The high-definition data tells a different story.

For this same well, the lateral discrepancy between the high-density continuous gyroscopic (HDCG) and MWD surveys was 50 ft at TD; the azimuth plot shows little or no systematic error (Figure 6). The lateral difference can be attributed to the lack of definition; in other words, the stationary surveys every 90 ft or so are not frequent enough to properly describe the wellbore trajectory.



**Figure 6:** Stationary and high-definition azimuth data that resulted in significant lateral differences.

## High-Definition Survey Data Post-Drilling

### Wellbore Tortuosity

The characterization of the wellbore regarding tortuosity at various length scales may be of crucial importance for the functionality and lifetime of permanently installed downhole equipment. For example, identification of highly tortuous sections will aid the placement of rod-guide wear sleeves. This increases the rod and tubing life and reduces the workover frequency. Another application is the identification of low tortuosity sections where downhole pumps, ESP, or other equipment will not be subject to excess bending. Also, the tortuosity results may help in evaluating the drilling equipment performance and the drilling process. The tortuosity analysis has the potential to contribute to technical and procedural improvements and cost savings in areas ranging from drilling operations to the completion phase and initial and long-term production.

The following case study compares dogleg inferred tortuosity comprising the drilling-induced deviations from the plan, as measured by an MWD survey at 93 ft intervals, versus the analysis of small-scale tortuosity data collected from a HDCG survey.

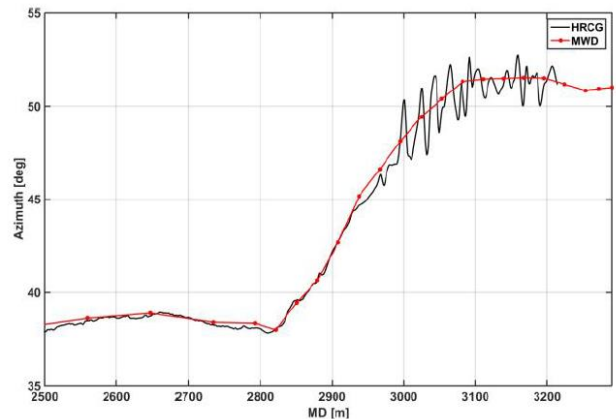
A deep-water offshore well drilled in Latin America with a rotary steerable system showed a straight tangent section with small doglegs, but there were problems associated with running casing to TD, at 3,290 m.

There were indications of issues with the well on the trip out of the hole with the 12 ¼ inches BHA. Back reaming was required from TD to 2,775 m. When running the 9 ⅝ inches casing, the string hung up at 3,264 m, and it could not go any further. Many attempts were made to pull the string free, but it remained stuck at 3,261 m. A clean out run of the 9 ⅝ inches casing was required and resulted in abandoning several meters of casing.

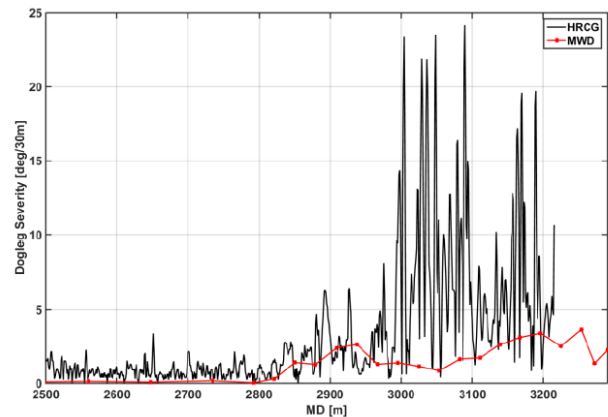
Even though there were several problems in this part of the well, the low dogleg severity suggested that the production equipment could be installed here.

Due to the premature failure of two production pumps, the operator decided to run a HDCG survey. Comparison between

the MWD and HDCG surveys showed no evidence of gross error in the MWD data but indicated rapid azimuth fluctuations not detected by the MWD survey, Figure 7-a.



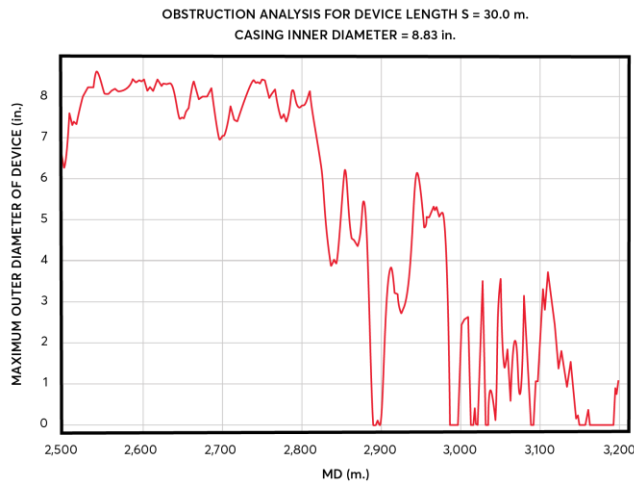
**Figure 7-a:** Azimuth comparison between stationary MWD surveys and HDCG.



**Figure 7-b:** Dogleg severity comparison between stationary MWD surveys and HDCG.

The dogleg severity based on the HDCG data also indicated higher tortuosity below 3,000 m but failed to provide a quantifiable measure (Figure 7b).

The tortuosity parameters (as defined by Bang, 2016) calculated from the HDCG revealed much more details about the trajectory of the wellbore. One of these parameters is the maximum outer diameter (Figure 8), which drops to zero at approximately 2,900 m and explains the issues with the casing and the production equipment.



**Figure 8:** An obstruction analysis.

The evidence from the HDCG resulted in a decision to place the production pumps 150 m higher than initially suggested to avoid future rework. The initial lack of information between the MWD survey stations (30 m separation) resulted in several weeks of complications with running casing and failure of artificial lift equipment. The inadequate information also resulted in lost production with significant extra costs to the operator (estimated to more than 7 million USD).

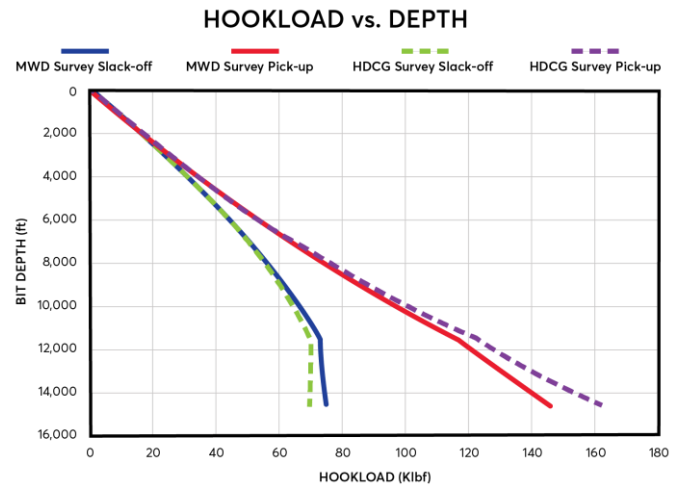
### Torque and Drag

Tortuosity is one of the critical factors in designing complex directional wells. Well path plans commonly generate smooth curves, whereas an actual well contains different levels of tortuosity and other trajectory irregularities. The difference between the planned smooth well profile and the actual well drilled can have a major impact on the torque and drag estimations for the well. In general, tortuosity is defined as the deviation from a straight trajectory. One way of quantifying the value is as the ratio of the actual path length to the straight-line length for a given depth distance (Bang 2016). However, there are many other definitions of tortuosity and similar or closely related terms, such as tortuosity index (Zhou 2016). Even though it is possible to model the wellbore trajectory in order to estimate a high-definition representation of the wellbore, having actual measurements is a simpler approach that eliminates guesswork.

The high-density measurements required for the torque and drag analysis can be made after drilling in an open hole or after running casing or tubing, but it is expected that open-hole measurements are the best input for torque and drag analysis.

Figure 9 shows that the torque and drag calculated from the MWD survey versus the HDCG survey were significantly different by as much as 5,000 pounds of force on the slack off and 18,000 pounds of force on the pickup. The operator was unable to set a mechanical packer using the the parameters obtained from torque and drag models based on MWD survey data. HDCG survey showed higher tortuosity and an updated

torque and drag model was generated using the high-definition data which allowed the operator to set the mechanical-set packer.

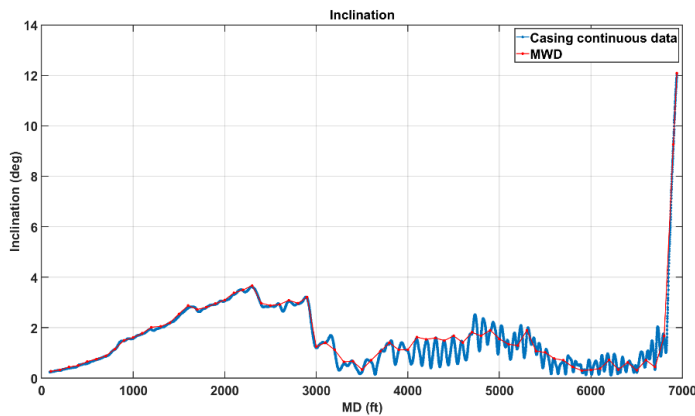


**Figure 9:** The torque and drag calculated from the MWD survey versus the HDCG survey.

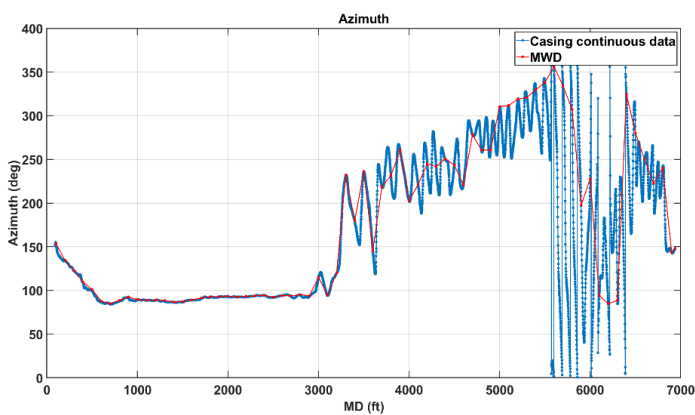
### Casing

Once the drilling has finished, the wellbore is cased. Even though the casing is inside the wellbore, usually this change is significant, particularly when looking at tortuosity. The tortuosity of the open hole plays only a secondary role when considering the installation of downhole equipment for artificial lift purposes. In the following field example, a high-definition gyro survey was requested by the production team since they encountered problems when trying to place an ESP. The open hole surveys measured by the MWD tool at 93 ft intervals show a somewhat straight well. The HDCG surveys, on the other hand, show large oscillations in inclination and azimuth after 3,000 ft. These oscillations generate a combined effect that is commonly known in the industry as buckling of the casing, spiralling or helical casing.

In the Figures 9 and 10, both the inclination and azimuth match well considering the spacing between successive MWD survey stations is 93 ft while the HDCG data is at 1 ft depth intervals.

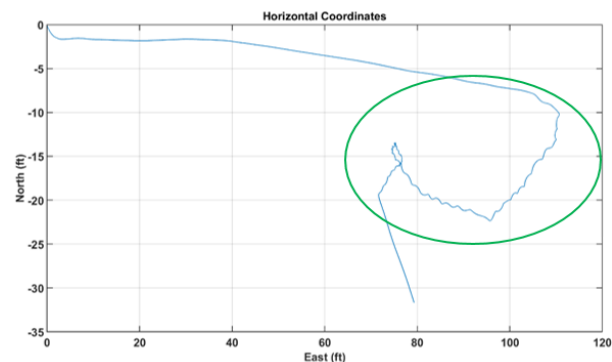


**Figure 10:** Inclination comparison between HDCG and stationary MWD.

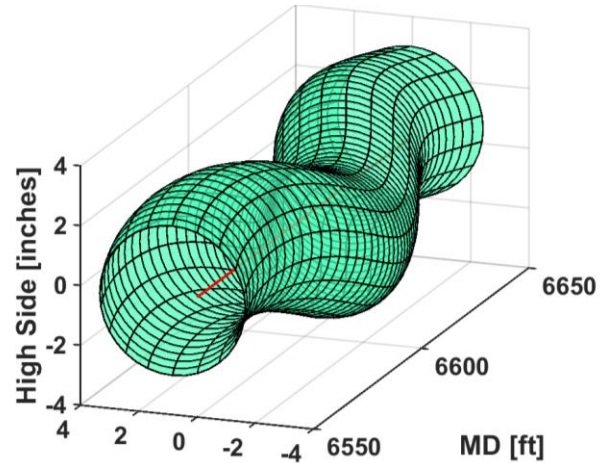


**Figure 11:** Azimuth comparison between HDCG and stationary MWD.

Figure 12 shows the horizontal coordinates on the left, confirming the helical shape of the casing (circled in green). Tortuosity analysis of the high-definition data, particularly the 3D rendering of the trajectory of the well, further reflects the helical shape; Figure 13. Another result of the tortuosity analysis is the estimation of the effective diameter; for this casing survey, the effective diameter was found to be 2.79 inches, which explains the fact that the ESP could not be placed at the desired depth.



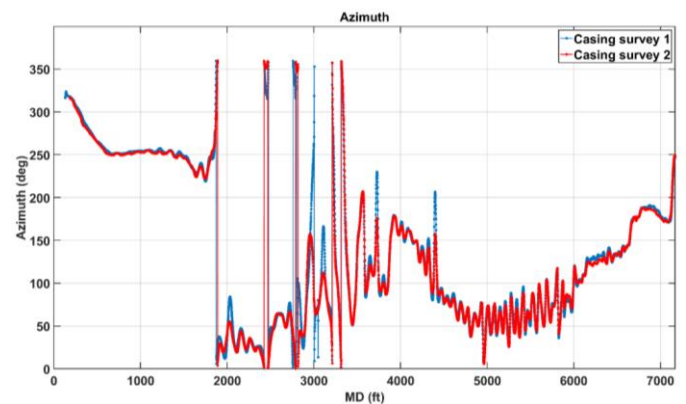
**Figure 12:** Horizontal coordinates that confirm the helical shape of the casing.



**Figure 13:** 3D rendering of the casing shape.

Root cause analysis performed by the operator concluded that the casing was placed in compression. This was a good “lessons learned” event, and subsequently, changes were made to the running casing procedure to prevent this from happening again. This well was converted to a gas lift, which required an extra half a million dollars expense to bring the well online, compared to the cost of using an ESP.

In this second example, similar issues with the casing were identified. The high-definition continuous gyro survey shows the spiralling of the casing after about 2,000 ft of measured depth. After seeing the results, the operator decided to perform a test, with the intention of seeing if the casing will recover its straight shape after it has been pulled with significant force. Figure 14 below shows the azimuth of the casing on the original survey in blue, and the red curve shows the shape of the casing after the casing has been pulled up 28 inches using 2 million pounds of force.



**Figure 14:** The azimuth of the original casing, and the azimuth of the casing after it was pulled 28 inches.

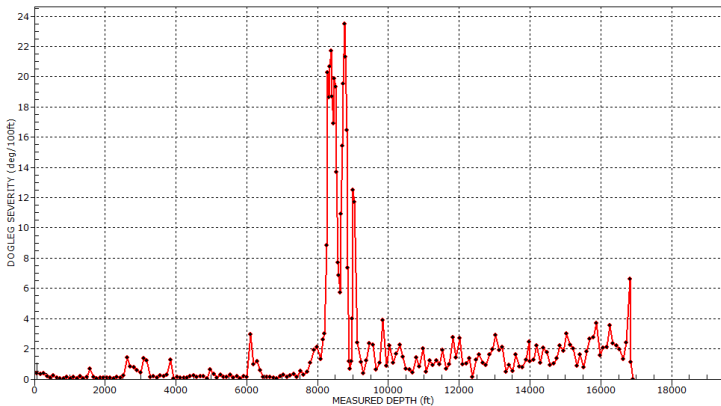
There is a small reduction in tortuosity, but for this particular case, it seems that once the casing is deformed, it is

very hard, maybe impossible, to fix it.

**ESP Placement**

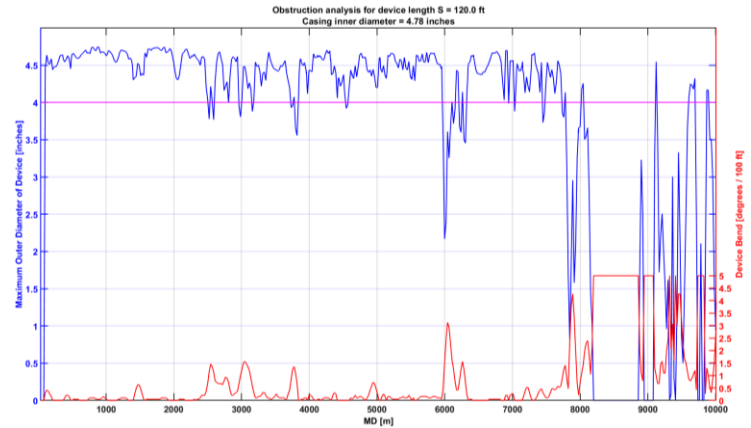
ESPs are used as a high-volume means of artificial lift. The cost of installing an ESP can be higher than 300,000 USD. ESP lengths vary significantly depending on several factors, such as production rate, intake pressure, etc. and in general, they measure between 80 and 160 ft in length. These pumps are usually placed in the vertical section of the well or at the lowest point that a straight tangent exists. Traditionally, the rule of thumb for placement was a section of the wellbore that had a dogleg of less than 2°/100 ft; independently of the actual pump length. The dogleg value is a very poor representation of the shape and curvature of the well since its value is based on the relative difference between two surveys nearly 100 ft apart and their use as a criterion for pump placement has shown to be unreliable (Ledroz 2017). The fact that the value of dogleg is high or low many times is a pseudo-random process related to the selection of the two points. With the use of high-density data every 1 ft, it is possible to analyze the trajectory of the wellbore for the specific length of the desired pump. Specifically for ESP placement, it is possible to calculate the effective diameter (Bang 2016) and determine at any depth the maximum diameter of a device that would barely touch the casing walls.

According to the dogleg severity derived from MWD surveys (Figure 15), the ESP could be set at 7,900 ft where the maximum dogleg appears to be under the 2°/100 ft limit.



**Figure 15:** MWD dogleg severity.

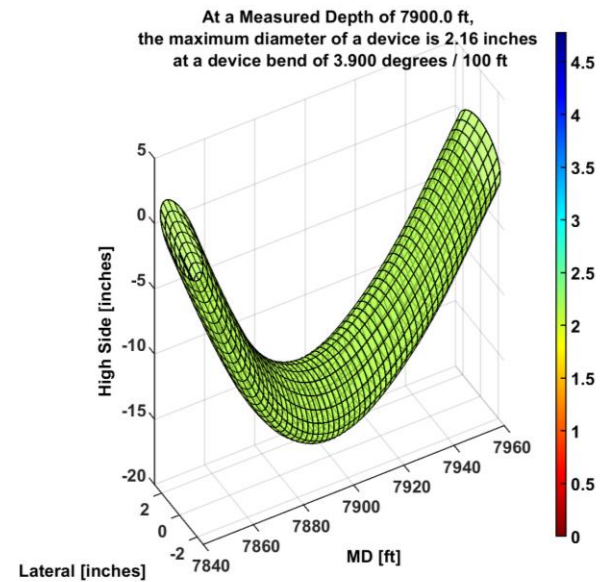
For this particular well, a 5.5 inch outer diameter production casing with a 4.67 inch inner diameter has been installed, and a high-definition continuous survey inside the casing has been run. The operator has had the ESP custom designed for this well. The diameter of the ESP was 4 inches and the length was 120 ft. These parameters are used to process the high-definition survey data providing results showing the best location for the ESP.



**Figure 16:** The maximum outer diameter that can fit in the casing.

The ESP needs to be placed in the vertical section of the well above kick-off point. Figure 16 shows the maximum outer diameter of the device that can fit in the production casing (blue) and the device bend up to 5°/100 ft (red). The magenta line is the diameter of the ESP. Based on the information provided, the software analyzed all the data and reports the maximum diameter of a 120 ft device as well as the bending that the device sees at each depth.

The first choice for the EPS placement that was considered at 7,900 ft based solely on the MWD dogleg calculation is clearly not a good option as the ESP will suffer a bending of almost 4°/100 ft with an effective diameter of only 2.16 inches (Figure 17). The obstruction analysis reveals that the 7,600 ft is a location at which the bending is only 0.277° while the effective diameter is larger than the ESP diameter (Figure 18).



**Figure 17:** 3D rendering of the casing at 7,900 ft.

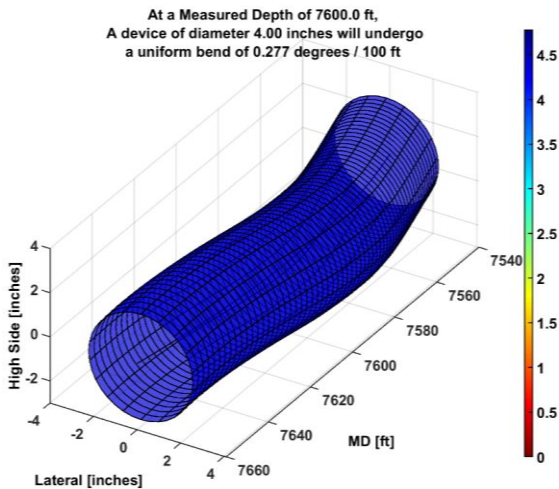


Figure 18: 3D rendering of the casing at 7,600 ft.

### Side Forces – Rod-Guides

In this example, the focus is on a well that has been producing on a beam pump with metal sucker rods for many years; however, this well had a history of sucker rod failures. The failure rate was about three times higher than adjacent wells. To get a better understanding of why the rods were failing at an elevated rate, the operator decided to run a high-definition continuous all attitude gyro to survey the production tubing.

The high-definition data was used to estimate the side forces of the rod against the production tubing (Jegbefume 2018). Areas where the sucker rod side forces exceed the tolerance, need to be analyzed to determine if a failure occurred in one of these areas. Rod guide sleeves are normally used when the side forces exceed 40 to 60 ft.lbs on the upstroke. In the following example, the side force computed based on the MWD surveys (Figure 19) is compared to the side force calculated using the high-definition data (Figure 20). The high-definition data generates larger side forces because it uses the actual trajectory of the wellbore, while the MWD assumes a smooth path between surveys. These larger side forces suggest that the initial number of rod-guides was likely not adequate and a new assessment based on the history of failures and the larger side forces was required.

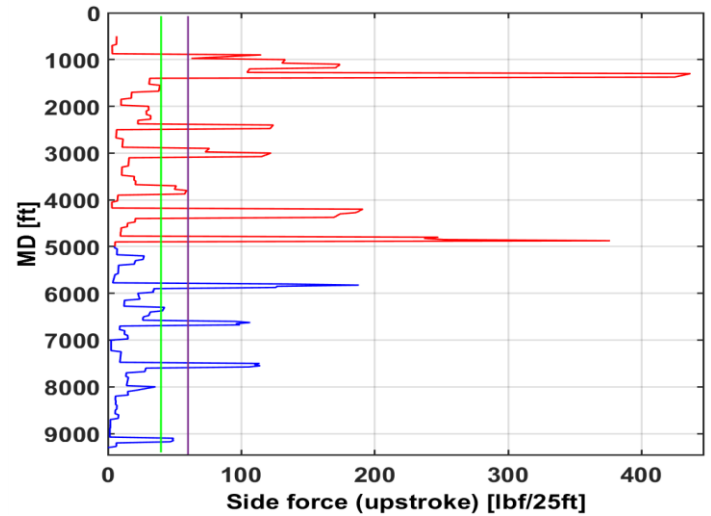


Figure 19: Side force computed based on the MWD surveys.

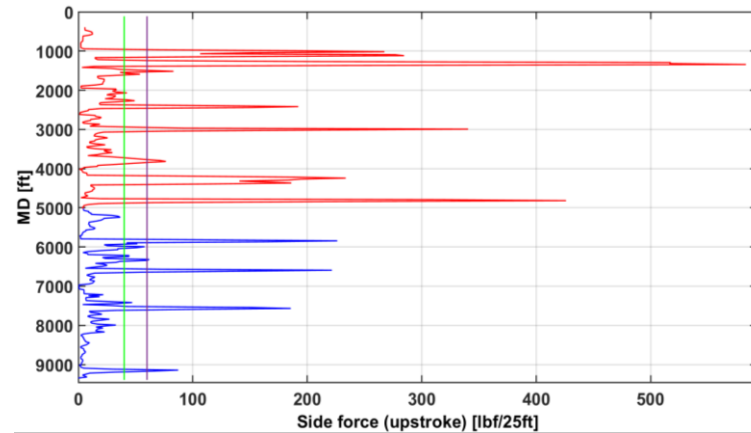


Figure 20: Side force calculated using the high-definition data.

### Conclusions

This paper presents several case histories showing how high-definition survey data can be used to provide a better understanding of the shape and tortuosity of the borehole in open hole, casing and tubing.

High-definition survey data acquired during drilling operations yields the following benefits:

- Allows the construction of smoother well paths.
- Reduces torque and drag allowing the lateral portion of the well to be extended.
- Continuous inclination acquired in build and drop sections reduces TVD error.
- Continuous azimuth reduces lateral errors generated while drilling a horizontal section allowing improvements in borehole spacing.

High-definition survey data acquired after drilling operations in casing or tubing provides valuable information which can extend the life of the production equipment. This has a significant impact on the repair cost, downtime and

overall return on investment. Benefits include:

- The calculation of wellbore tortuosity.
- Improvements to torque and drag simulations.
- Identification of problems encountered when running casing.
- Help to identify if casing or tubing is set in compression.
- Determination of the best location to set an ESP, and extend its life.
- Accurate calculation of sucker rod side forces used for rod-guide sleeve placement.

Pressure to drill better quality wells, increase production and reduce the total cost of a well will drive future applications of high-definition survey data.

### Acknowledgments

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### Nomenclature

<i>BHA</i>	= <i>Bottomhole assembly</i>
<i>HDCG</i>	= <i>High-density continuous gyroscopic</i>
<i>MWD</i>	= <i>Measurement while drilling</i>
<i>ROP</i>	= <i>Rate of penetration</i>
<i>TD</i>	= <i>Total depth</i>
<i>TVD</i>	= <i>True vertical Depth</i>

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