Successful Rotary Steerable Drilling in Deepwater Wells under Low Flow Rate Conditions

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Abstract

While recent advances in rotary steerable drilling technology have enabled the industry to drill wells more efficiently with superior wellbore quality, planning for such wells is a challenge in the deepwater environment, where specialty tools are incorporated above the rotary steerable system. A jetted reaming device above the rotary steerable system imposes restrictions on the available flow rate and pilot bit pressure drop, which are already limited by the available stand pipe pressure. Extreme low flow rate rotary steerable tools are now available to drill wells successfully and decode MWD data accurately on surface under such challenging conditions.

Three consecutive deepwater development side tracks were drilled successfully with the advanced rotary steerable system under low flow rates. The paper addresses concerns and challenges of planning drilling hydraulics for such deepwater wells. The paper serves as a guide to understanding and modeling these complexities, namely (1) high temperature/high pressure (HTHP) compressibility and (2) down-hole split flow hydraulics. The paper also provides recommendations for proper tool selection to drill and decode successfully under such low flow rates.

Introduction

The objective of an optimized hydraulics program is to provide the maximum hydraulic horsepower (HHP) at the bit and provide maximum hole cleaning possible working within the limitations of stand pipe pressure and formation constraints. The objective of an automated rotary steerable system is to provide precise directional control with continuous drill string rotation and MWD data. [1, 2] As drilling depth increases, the flow rates are further restricted owing to the limitations outlined above. The use of a flow bypassing expandable reamer, which is typical of some deepwater operations, further restricts the available flow required for MWD telemetry tools inside the rotary steerable system. Proper tool selection and design, which are specific to the application, are necessary to obtain the best results from the limited flow

rate. The compressibility of synthetic mud under 20,000 psi pressure conditions further limits the ability to pump at required flow rates owing to stand pipe pressure and ECD limitations.

Deepwater Drilling Hydraulics

Bottomhole Pressures (BHP) exceeding 18,000 psi are typical of deepwater wells in the Gulf of Mexico (GOM). Depending upon the water depth, static seabed temperatures approach 34º F, while the static geothermal Bottom Hole Temperatures (BHT) approach 230º F for typical GOM deepwater wells. The drilling fluid experiences significant temperature and pressure changes, which have a direct impact on the fluid's density and viscosity profiles. [3, 4] These changes further impact the hydraulics calculations. In some cases, these changes have required a reduction in the flow rate to stay within the stand pipe pressure limitations . Table 1 shows planning hydraulics and comparisons with actual drilling hydraulics for one of the case history wells. As seen from the table, to achieve a Stand Pipe Pressure (SPP) of 4,250 psi, hydraulics simulations predicted a flow rate of 382 gpm without mud compressibility effects. However, when temperature and pressure effects are considered on the mud system, the Advantage[SM] System HTHP Hydraulics program reduces the flow rate by approx. 10% to 345 gpm, which compares well with actual rig measurements of 338 gpm.

While the above phenomenon is typical, it needs to be taken into account for proper tool selection. The advent of rotary steerable systems has enabled us to drill more complex wells with smoother trajectories. [5] However, complex wells also result in further restrictions in flow rates, because of increased pressure drops and maximum SPP limitations.

The use of a flow bypassing expandable reamer could reduce the flow through the bit by approx. 5%-35%, depending upon the nozzle selection and flow rates. When pumping 350 gpm in a 8-1/2" hole section, a further reduction of 20% means a flow rate of approx. 280 gpm through the bit. The split flow is calculated using a hydraulics program, which equates the pressure differential at the reamer to that of the cumulative

pressure drop below the reamer.[6]

Rotary Steerable System Technology

Experience over the last several years has shown that rotary closed loop systems (RCLS) have several advantages over conventional motor drilling operations (Fig. 1) [7,8,9]. There are several variants of this technology currently available in the industry. It is also important to note that not all rotary steerable systems are RCLS systems. In a RCLS system near bit inclination values are frequently compared with the target inclination values stored in the tool's memory. The value of this automated closed loop control is that the wellbore trajectory is continuously maintained by continuous steering as dictated by the logic controller in the tool. Systems which do not have a precisely adjustable closed-loop control steering system must allow the wellpath to deviate away from the planned trajectory and then manually steer back to plan. A more detailed discussion of RCLS is available from previously published literature[8].

The AutoTrak[®] G3 RCLS system employed to drill the deepwater wells referred in this paper uses a "hybrid" operating principle rather than only "push the bit" or a "point the bit" system.[8, 10] This feature, along with the ability to automatically choose from any of the approx. 7,500 steering vectors, makes continuous steering possible, resulting in a smooth trajectory and precise directional control in these deepwater environments.[8] Another distinguishing feature, which is useful at deepwater depths, is the non-dependency on bit pressure drop. In other words, the RCLS was designed to function irrespective of the pressure drop on the bit. Therefore, while the MWD may dictate the amount of minimum flow required for telemetry and tool power up, the steering unit can still function precisely even at ultra low flow rates. This capability results in a smoother borehole with no correction runs required to smooth out ledges.

The basic RCLS system, shown in Fig. 1, consists of a steering unit, sensor sub and a power communication system. The steering unit has three individually powered steering pads for precise directional control. Even if one of the steering ribs were to fail, the redundant design of the system enables the tool to function and steer with some directional control. The sensor sub, referred to as the OnTrak[®] system, has all the electronics and provides Pressure, Multiple Propagation Resistivity, Gamma ray, Directional and Vibration Stick Slip (VSS) measurements. The Bi-directional Communications and Power Module (BCPM) provides power and communications services. The modularity of the RCLS system allows for other LWD services to be added to the system. Tool details were discussed at length in previously published papers.[7, 8]

Extreme Low Flow BCPM Setup for Accurate Telemetry

BCPM is the communications and power module for the rotary steerable system, housing the pulser (Fig. 2). The pulser within the system was modified to optimize the size of the pulse at specific flow rates. The optimized pulse was produced by implementing a broader range of restrictors to enable the pulser to be setup with a restrictor that matched exactly the flow rate ranges expected at the BHA. This matching is crucial for success of the wells where the flow rates are limited and a portion of the flow would be bypassed through the reamer placed in the BHA above the pulser. The pulser design was modified to increase the pulse height at the MWD tool. The new design, called HPP (High Pulse Pressure), involved increasing the force on the spring that is used to choke the pulse pressure of the pulser. The extra force on the spring results in a higher differential pressure across the pulser and a significant increase in pulse height. Due to the increase in differential pressure, some parts of the pulser were manufactured from a diamond material to reduce wear.

Deepwater Decoding Challenges

Data transmission at these deeper depths is a challenge due to low pulse pressures. To ensure that the data was transmitted properly to the surface, several simulations were developed and run to predict the final pulse height and shape at surface for a given down-hole pulse height. The BHA, drill pipe and surface pipe were modeled along with the known mud properties. The graphical output (Fig. 3) shows the pulse traveling through the pipe and the estimated pulse height at the surface. This simulation was used to optimize pulser setup and to establish a measurable confidence factor when decoding at these depths. The measured average pulse height from actual drilling operations of the deepwater wells discussed in this paper was more than sufficient for decoding and good data clarity.

Software improvements were made to the system for better decoding even in cases where pulse height at the surface was weak.   The rig was equipped with new sensors and hardware to remove the effect of the pump stroke signature on the pump pressure signal. The surface software was modified to improve decoding at all depths by use of adaptive correlators for signal detection. As a result of the modifications made to the surface system, the drilling team was able to produce excellent quality real-time logs for the entirety of each of the three wells.

Downlinking at these deepwater depths and high pressure conditions needs particular attention because it is an essential part of the automated rotary steerable drilling.   Proprietary downlinking improvements were

made to double the average speed of downlinking and improve the reliability of the signal sent down hole.

GOM Case Histories

Three consecutive deep side track wells were drilled for a major operator in the Green Canyon field in GOM. Water depths were around 4,000 ft. Average sidetrack depth was 21,000 ft with TD's at approx. 26,000 ft (Table 2). Average downhole circulation pressure was 20,000 psi. A flow bypassing reamer was also used in the drilling assembly (Table 3), which further limited the available flow to the RCLS tool. Owing to the extreme low flow pulser technology and the best practices outlined above, 99% or better decoding was possible with very good pulse height at the surface.

Green Canyon Well #1

The original well was sidetracked from 9-7/8" casing at 21,448 ft. Plan was to drill a 8-½" x 9-7/8" hole section with a rotary steerable system in conjunction with a expandable reamer. Table 3 contains the approximate bottom hole assembly that was used for all the three case histories described here. A complete triple combo service (Gamma ray, Resistivity and Density Neutron) was used for detailed LWD service.

The rotary steerable assembly was able to turn and build angle off a marginal cement plug. The 4,112-ft hole section was drilled in one run to reach TD. A dogleg severity of 4.13⁰/100 ft was planned over 1,330 ft of the section and was accurately achieved through the precise steering vector programming capability of the RCLS.

Extensive hydraulics planning was performed to determine the optimum flow rate and split flow calculations using the reamer. As shown in Table 1, temperature and pressure effects on the mud system were considered in modeling the hydraulics. Density and viscosity corrections were made using PVT data of the base oil and Fann 70 data of the mud system, respectively.

Due to synthetic mud compressibility in these deepwater wells, the fluid was pumped at 338 gpm as opposed to the planned 382 gpm. During drilling, 13% of the flow was bypassed through the jets of the reaming device, leaving an approximate flow rate of 294 gpm at the RCLS tool. The first column under Table 2 contains operational information for current well. Even though the section was drilled in one run, the expandable reamer did not open the hole to 9-7/8" diameter as planned and a separate hole opening run had to be run to TD the well.

The RCLS drilling was deemed a success by the operator because of the employment of the Extreme Low Flow Telemetry System, which helped decode 99.8% of the downhole data and achieved good downlinking. The Vibration Stick Slip (VSS) service also helped drill the hole in one run with careful monitoring of downhole dysfunctions.

Green Canyon Well #2

The original well was sidetracked from 9-7/8" casing at 21,540 ft. The plan was to drill a 8-1/2" x 9-7/8" hole section with a rotary steerable system in conjunction with a expandable reamer. The KOP was 22,540 ft and TD of the well was 26,405 ft MD / 25,698 ft TVD.

The RCLS was used with an Extreme Low Flow Telemetry configuration. Data transmission and down-linking was successful throughout the job. 99% trans-mitted data was decoded. This assembly was able to achieve 4.5⁰–4.9⁰ /100 ft build rate at the beginning of the sidetrack. The precise steering control of the system and wide range of steering settings proved valuable in drilling the section in a single run even though drilling targets were altered during the run.

The BHA configuration was identical to Case #1, except for the addition of the downhole CoPilot® (Drilling Dynamics Tool) WOB/torque/bending moment measurement tool.[11,12] The tool was positioned above the resistivity/gamma ray/directional sensor to provide indications if the downhole expandable reamer was functional in opening the hole to 9-7/8" by comparing the downhole WOB and torque to the surface WOB and torque. As seen on the log during reaming operation of a previously drilled section (Fig. 4), the downhole WOB and torque were close to zero while the surface WOB was approx. 25 klb and surface torque was approx 15 kft-lb. These measurements indicate that the reamer was open at this point. When drilling resumed, there was still a separation between the downhole WOB (DH WOB from the drilling dynamics tool) and the surface of about 10,000 lb. The surface torque increased from the drilling torque of the bit after drilling was resumed at 22:25 hrs. Fig. 5 is a drilling dynamics log for a deeper interval, indicating a possibility that the reamer could be under gauge or closed, since the surface WOB matches the downhole WOB from approximately 26,018 ft to TD. Note the separation of downhole and surface WOB above 26,018 ft; the approximate 10-klb separation of surface and downhole WOB indicates the weight that is used by the hole opener. The expandable reamer operations in the current well were also not a success due to some mechanical failures.

The RCLS operation was successful with 100% data decoding in this well. As indicated in column 2 of Table 2, 18% of the flow was bypassed and the tool operated at 328 gpm flow rate.

Green Canyon Well #3

This well was the third sidetrack well in the series. The well was sidetracked from 22,839 ft to TD at 25,682 MD / 24,629 ft TVD. Column 3 of Table 2 contains a few more operational details. A whipstock was prematurely set and was 180⁰ off from the desired direction. A sharp turn in azimuth was required to stay away from a neighboring well and turn back to the original planned path (Fig. 6). The RCLS assembly steered the wellbore successfully around surrounding wellbores and back to the original plan.

The BHA configuration was identical to the one in Case #1, except that the expandable flow bypassing reamer was replaced with a reamer without any flow bypass. During the drilling operation, however, pressure decrease on the stand pipe was noticed, which alerted the drilling team to the possibility of a downhole washout. The data transmitted from the RCLS (Fig. 7) confirmed the suspicion and eventually 35% of the flow was bypassing through the failed reamer seals (Column 3 of Table 2). Nevertheless, the Low Flow Telemetry system helped decode MWD data at 100%. A GOM storm and some tool problems led to some interruptions on this well. The well was subsequently drilled without a reamer, followed by a separate under reamer assembly to open the hole to the desired 9-7/8" diameter.

Since none of the flow was to be diverted from the drilling system, a Low Flow BCPM was used to customize the RCLS as opposed to the Extreme Low Flow BCPM. When substantial flow bypass occurred, some signal attenuation was noticed. However, the amplitude of the pulse height was more than adequate for good decoding and data clarity.

Conclusions

The three deepwater sidetracks discussed in the article were deemed a success with respect to testing the abilities of current generation RCLS. The authors wish to share the following conclusions with the industry:

- Successful deepwater operations are dependent upon detailed hydraulics preplanning. Deepwater temperature effects should be considered during the planning phase. Compressibility of the mud could affect flow rates by approx. 10%.
- A field validated HTHP Hydraulics model would provide a good idea of pressure drops and flow rates that are to be expected. It is particularly beneficial to run these models when GOM water depths exceed 3,000 ft. and bottom hole circulating pressures are above 15,000 psi.
- Optimizing the pulser equipment to match the flow rate regime proved to be quite successful in the current operations. A BCPM, similar to the Extreme

Low Flow BCPM described in this article, is recommended for deepwater and ultra deepwater operations. In other words, customize the RCLS to the specific application to ensure maximum decoding capability and clarity at the deepwater depths.
- Plan for lower than expected flow rates because the RCLS may not see the desired flow rates down hole due to either compressibility or more than expected flow split or plugged bit nozzle. Higher flow rates are also possible, if the reamer nozzles are only partially open.
- RCLS whose operation is not dependent upon the pressure differential across the bit provides for flexibility in flow rates in an already flow-rate limited environment because of SPP and ECD limitations.
- Planning and coordination with all service companies and the operator are key factors for a successful deepwater operation.

Acknowledgments

Nomenclature

BHA   = Bottomhole assembly
BOP   = Blowout preventer
CCN   = Caliper Corrected Neutron
ECD   = Equivalent circulation density
EMW = Equivalent mud weight
GPM   = Gallons per minute (flow rate)
KOP   = Kick Off Point
LWD   = Logging While Drilling
MWD = Measurement While Drilling
ORD   = Optimized Rotational Density
PVT   = Pressure, Volume and Temperature
RKB   = Rig floor kelly bushing elevation
ROP   = Drilling rate of penetration
RPM   = Revolutions per minute
TD   = Total depth
TVD   = True vertical depth
WOB   = Weight on bit

SI Metric Conversion Factors

ºF	(ºF – 32)/1.8	= ºC
ft	x 3.048*	E - 01 = m
gal	x 3.785 412	E -03 = m^3
in.	x 2.54*	E + 00 = cm
lbf	x 4.448 222	E +00 = N
lbm	x 4.535 924	E – 01 = kg
psi	x 6.894 757	E+ 00 = kPa

*Conversion factor is exact

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Green Canyon Well #1	Simulation Results (case 1)	Simulation Results (Case 2)	Actual Results
Depth, feet			25520
Hole Size, in			8 ½
Last Casing Size, in	Input data is same as the data shown under actual results. Only other input in the simulations is the flow rate, which was altered to maintain a target SPP of approximately 4250psi.		9 7/8
Drill pipe size, in			5 ½
Bit Nozzles, in/32			7 X 12
Reamer Nozzles, in/32			1 X 8
Mud System			SBM
Surface Mud Weight, ppg			14.2
ROP, ft/hr			44.3
String rotation, RPM			140
Flow rate in, GPM	382	345	338
Flow Split (Flow Bypass)	12.0%	12.5%	13%
SPP, psi	4253	4256	4250
ECD, ppg	15.18	15.61	15.57
BHP (Circulating), psi	19573	20122	20094
BHT (Circulating), $^\circ$F	N/A	190	191
Transmitted Data	N/A	N/A	99.8%

Table 1. To stay within a targeted SPP, flow rate is reduced to compensate for the effects of synthetic mud compressibility

Well Name	Well #1	Well #2	Well #3
Depth, feet	25520	26405	25682
Hole Size, in	8 ½	8 ½	8 ½
Last Casing Size, in	9 7/8	9 7/8	9 7/8
Drill pipe size, in	5 ½	5 ½	5 ½
Bit Nozzles, in/32	7X12	3X14, 4X9	0.72 TFA
Reamer Nozzles, in/32	1 X 8	1 X 10	None
Mud System	SBM	SBM	SBM
Surface Mud Weight, ppg	14.2	13.5	14.0
ROP, ft/hr	44.3	55.8	44.9
String rotation, RPM	140	100	130
Flow rate in, GPM	338	400	390
Flow Split (Flow Bypass)	13%	18%	35%
SPP, psi	4250	4300	4280
ECD, ppg	15.57	14.50	14.90
BHP (Circulating), psi	20094	19376	19082
BHT (Circulating), $^\circ$F	191	201	197
Transmitted Data	99.8%	100%	100%

Table 2. Wellsite data - highlighting low flow rates and split flow

	5 7/8" Drill pipe
	5 ½" Drill pipe
	5 ½" HWDP
	5 ½" Accelerator Jar
	5 ½" HWDP
	5 ½" Hydraulic Jar
	5 ½" HWDP
	6 3/4" Drill collar
	8 ¾" String Stabilizer
	6 ½" NM Drill Collar
	9 7/8" Reamer
	8 ¾" NM Stabilizer
	6 ¾" CCN (Neutron)
	6 ¾" ORD (Density)
	6 3/4" RCLS
	8 ½" Bit

Table 3. 6 ¾-inch. RCLS BHA

Power & Communications

Sensor Sub

Steering Unit

Vibration & stick slip

Directional

27.5 ft

Multiple Propagation

21.6 ft

Azimuthal Gamma

Pressure

17.7 ft

16.7 ft

Inclination

3.1 ft
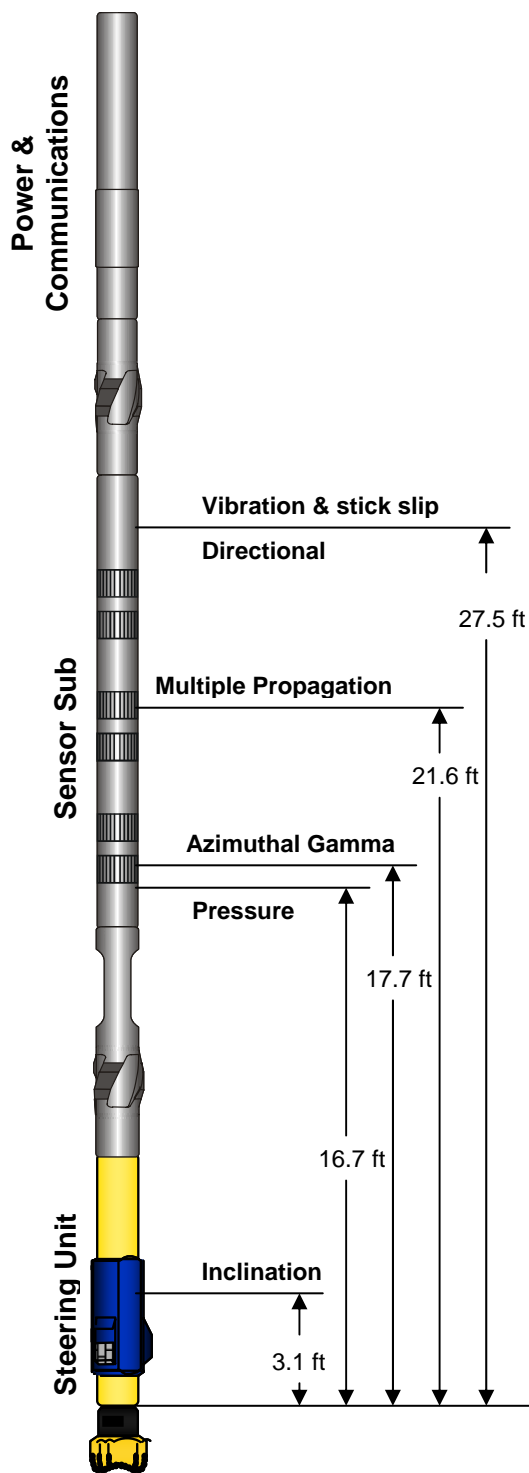
Figure 1 : AutoTrak® G3
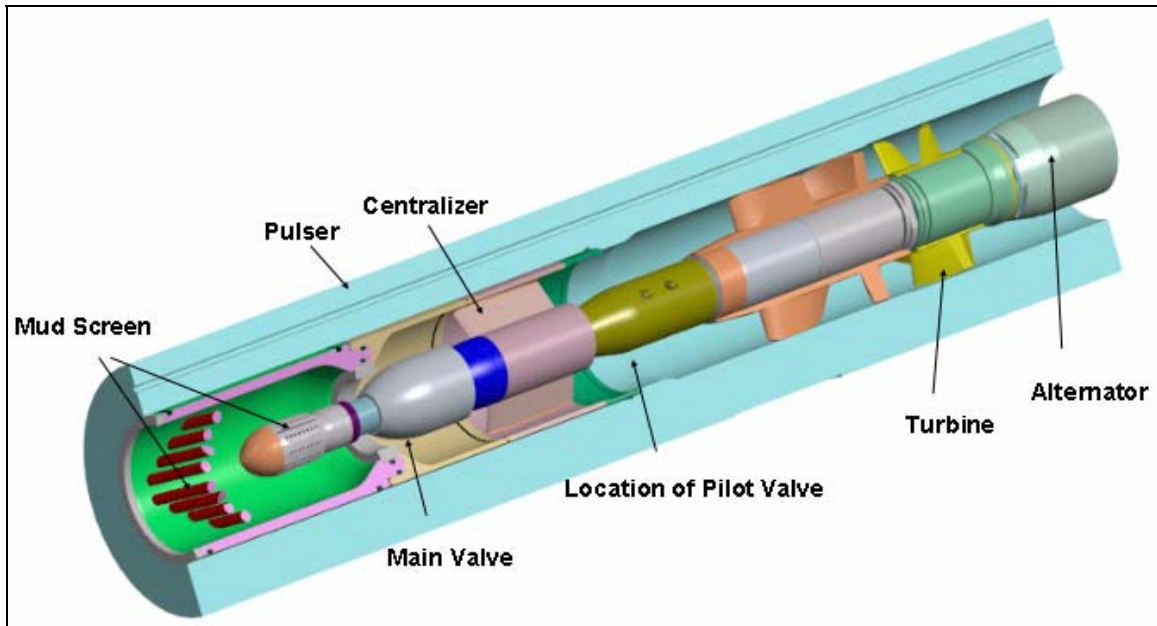
Figure 2. BCPM showing pulser and turbine assembly
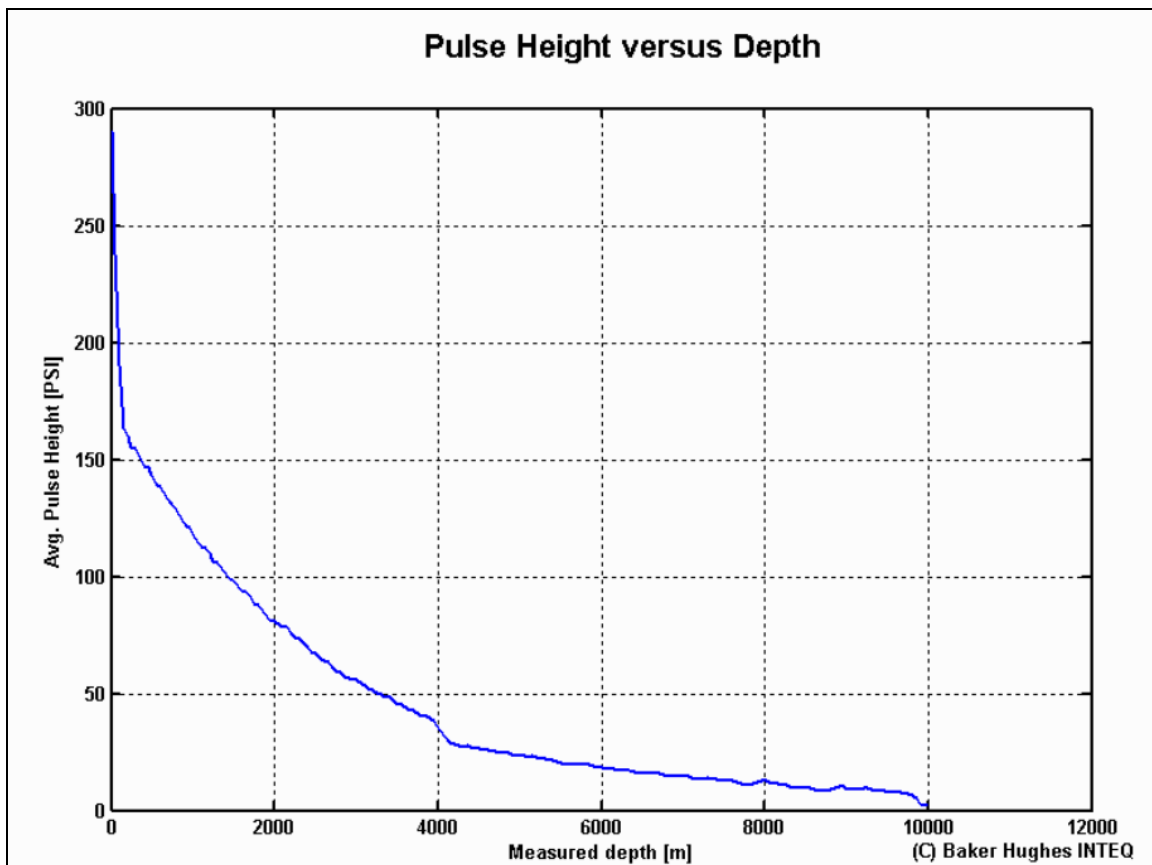

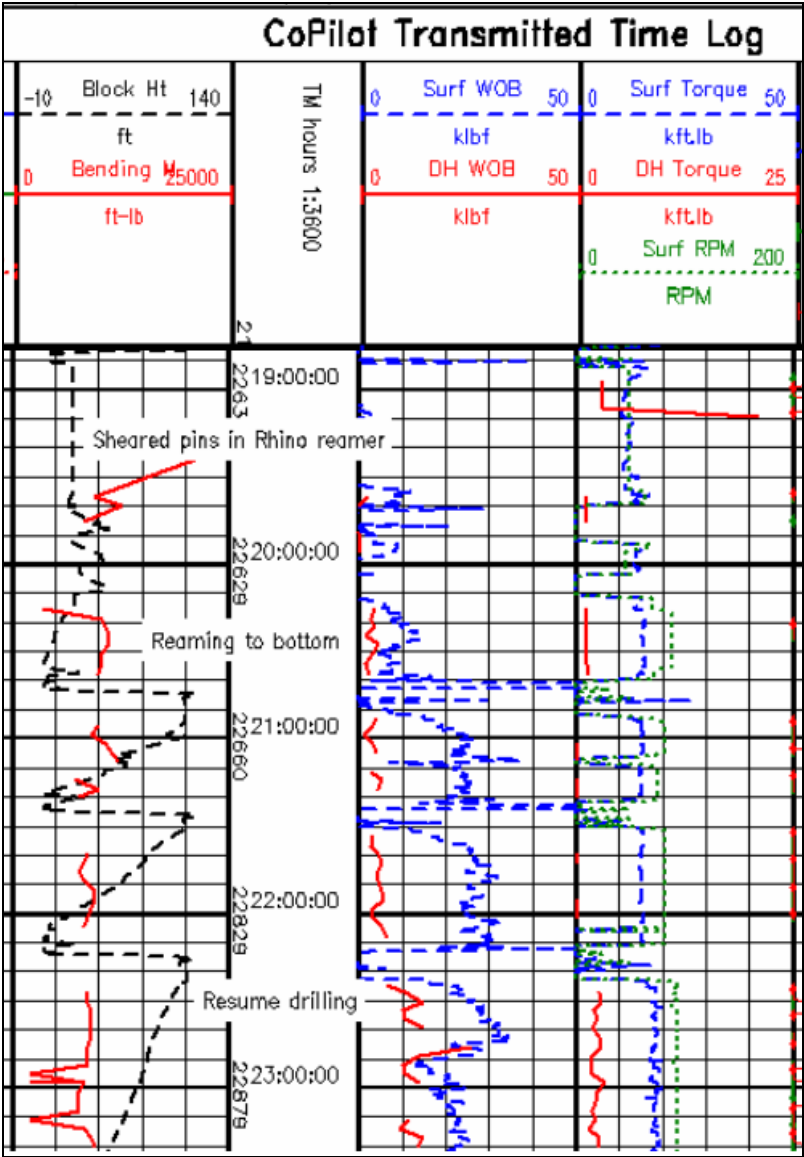**Figure 3. Effect of Depth on Pulse Height**

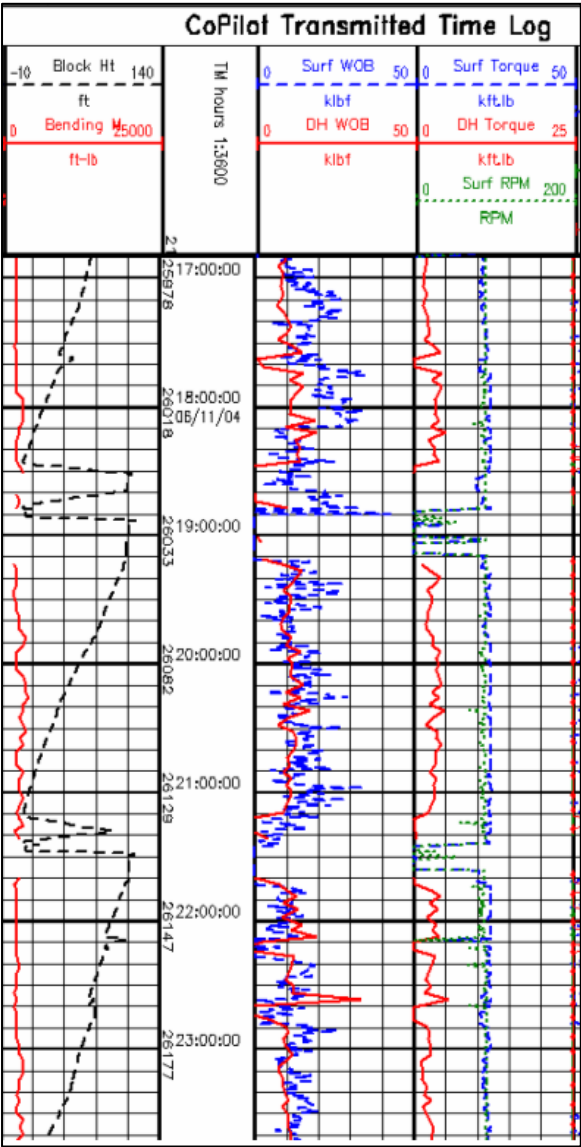**Figure 4. Down Hole WOB shows separation from surface WOB**

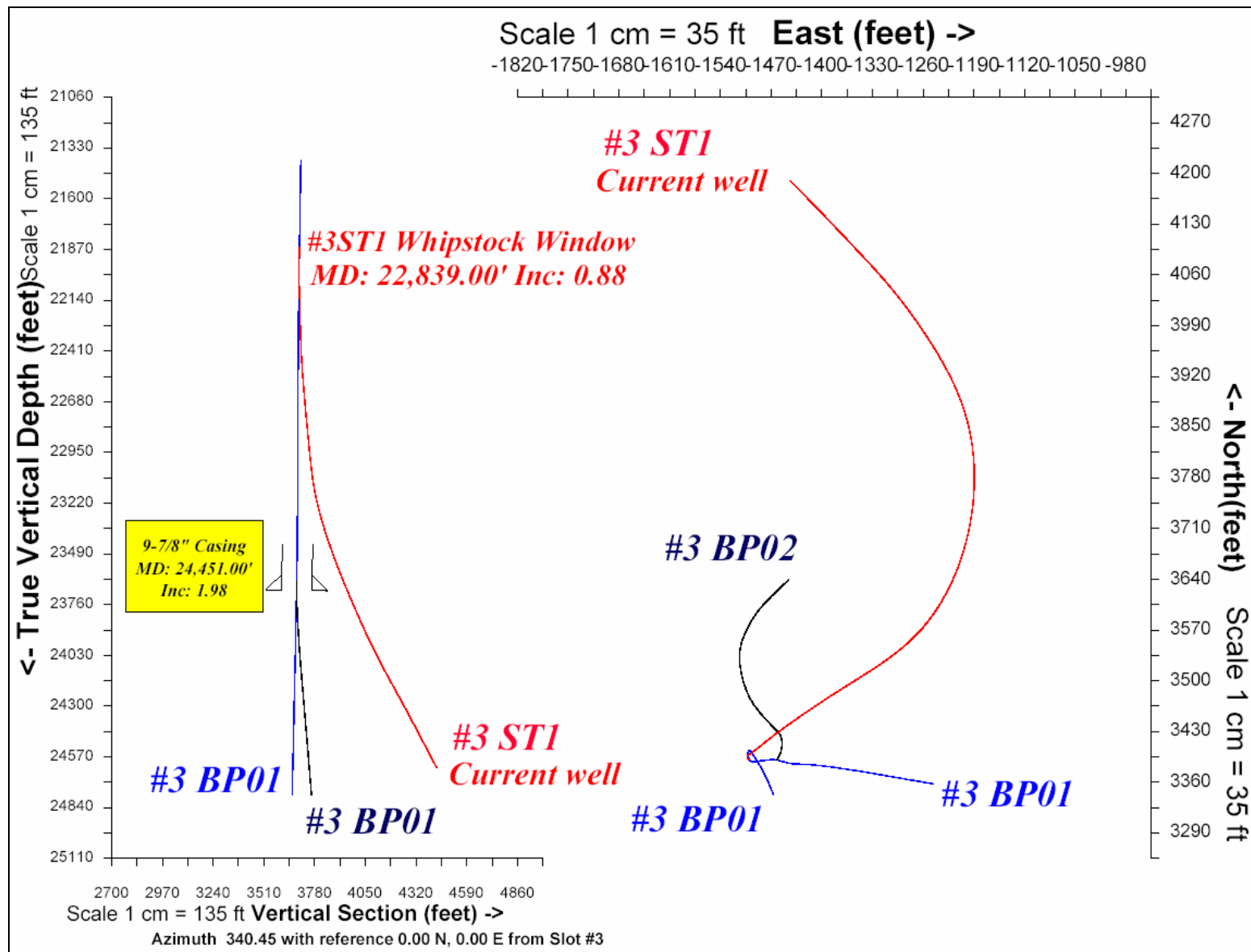**Figure 5. Surface and Down Hole WOB merge**

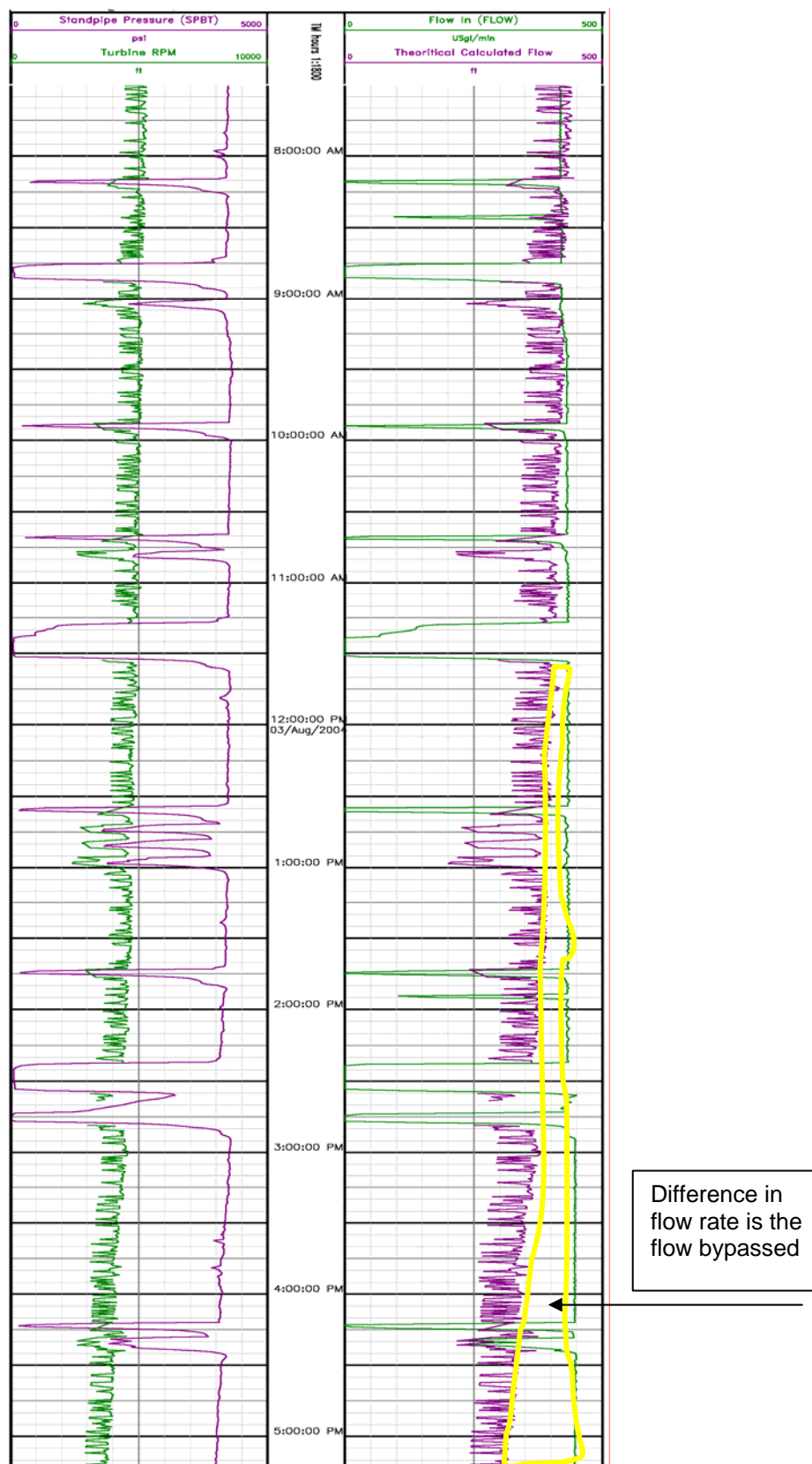**Figure 6. Green Canyon Well#3: Vertical Section and Plan View**

Figure 7. Green Canyon Well #3: Theoretical flow rate calculated from downhole turbine RPM