MAJOR PROJECT REPORT

SUBMISSION ON:

SNAKE WELLS- A NEW APPROACH TO HIGH DIPPING MULTI-LAYERED THIN RESERVOIRS

UNDER THE MENTORSHIP OF

Mr. R.P Soni

(Professor, Department of Petroleum Engineering & Earth Sciences)

SUBMITTED BY:

Apoorv Agarwal	R870212007
Ayush Rastogi	R870212009

Mentor's name and signature
(Mr. R.P Soni)

Course Coordinator's name and sign
(Dr. Pushpa Sharma)

B.Tech. Applied Petroleum Engineering (Upstream)
Batch: 2012-2016
Department of Petroleum Engineering & Earth Sciences
University of Petroleum and Energy Studies, Dehradun

CERTIFICATE

This is to certify that this project report entitled **“Snake Wells – A new approach to high dipping multi-layered thin reservoirs ”** submitted to “**University of Petroleum and Energy Studies, Dehradun”** is a bonafide record of work done by **“Apoorv Agarwal (R870212007) and Ayush Rastogi (R870212009)”** under my supervision from **“August 2015**” to “**April 2016”.**

Mr. R.P. Soni
Professor
Department of Petroleum Engineering
&
Earth Sciences

Place : Dehradun
Date :

DECLARATION BY THE AUTHORS

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Apoorv Agarwal
R8270212007

Ayush Rastogi
R8270212009

Place: Dehradun
Date :

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ABSTRACT

Snake wells are laterally weaving snaking' extended reach horizontal wells that drain a number of vertically stacked, structurally dipping reservoirs. This creates multiple drainage points in each sand and effectively achieves a similar drainage pattern to a multilateral well at a fraction of the cost and technical complexity. The wells are completed with multiple hydraulically controlled interval control valves (ICV) and external casing packers or swell able packers, in addition, the completion includes permanent downhole gauges (PDHG) and distributed temperature sensing (DTS). The well design not only initiates initial clean-up, but is used for reservoir management purposes and to manage gas and water breakthrough. Throughout the well life, variable ICVs are used to achieve equal drawdown along the well bore leading to a significant increase in reserves by delaying gas breakthrough.

Champion West Field was discovered in 1975 and is situated approximately 7 Km north-northwest of the Champion Main Field and 10 km north-northeast of the Iron Duke Field. Water depth in the area is around 40 to 47 m. It is characterised by about 1200 m of vertical reservoir sequence distributed over an area of about 40 km in 15 main blocks, with complex and variable fluid distributions including thin oil rims below large gas caps. Close to 100 individual reservoir units occur within each fault block.

Although, as fascinating the topic might look, drilling and completing such a type of the well is itself a great challenge. The kind of BHA used, the kind of completion practices adopted are no new, but these had to be used with utmost care and future prediction.

Hole cleaning, Shale Instability, BHA design, are the general problems experienced during the drilling of such wells. There are other drilling complications too as out of 16 wells drilled, 13 had to be side-tracked.

The completion process was also completed in three phases. BSP adopted/ changed its completion strategies many times depending on the complexity of the reservoir. For the first time the concept started when DTS (Distributed Temperature Sensors) were first installed in two wells. In phase 2, the completions were modified accordingly where smart stingers, external casing packers (ECP) and DTS are included. The smart stingers comprised of internal control valves (ICV), lubricator valves (LV) and permanent down hole gauges (PDHG). For the 3rd time, less diameter tubing and less diameter liner was used so that they can sustain more drag and torque.

Suggestions for minimising those drilling problems have been provided at the end of this report.

EXECUTIVE SUMMARY

This project deals with the entire new concept of Snake Wells. What are they, Why were they drilled, Where were they drilled, What was the technology used, What were the problems, How were they mitigated are some questions answered in this project. This project report also covers some of the basic Horizontal Wells technology literature including Dog Leg Severity, Hole Cleaning, Mud Systems and ECD management.

The questions answered are based on the research done of the entire free resources available on Internet. Analysing was done on the facts and figures crossed through the literature and possible solutions are suggested are suggested at the end. Analysing the literature revealed that these type of wells are limited only to a particular type of stratigraphy in the reservoir (high dipping multi-layered thin reservoirs). Also, the literature revealed that a no. of **"Drilling Complications"** are faced by these wells like Hole Cleaning, Shale Instability and BHA design.

Literature Research for the different phases of completions adopted for snake wells was also done. The first phase used DTS (Distributed Temperature Sensor). The second phase used ICVs (Internal Control Valves), Pressure Downhole Gauges (PDHG). Second phase still had problems of Torque and Drag, hence in the third phase, diameters of tubing and liner were reduced.

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INTRODUCTION

Snake Wells is a term used by Shell Oil to refer to a series of oil wells drilled in the Champion West oil field offshore Brunei. The wells used a combination of technologies including extended reach drilling, swell able wellbore packers and remotely operated zonal isolation and control. The directional drilling technique allows the path of the well to be directed to achieve contact with as many potentially producing features as possible. This results in a "snake like" well path which weaves up and down through multiple geological features in order to achieve maximum reservoir drainage.

Snake wells are laterally weaving extended reach horizontal wells that drain a number of vertically stacked, structurally dipping reservoirs. This creates multiple drainage points in each sand and effectively achieves a similar drainage pattern to a multilateral well at a fraction of the cost and technical complexity. The wells are completed with multiple hydraulically controlled interval control valves (ICV) and external casing packers or swell able packers. In addition, the completion includes permanent downhole gauges (PDHG) and distributed temperature sensing (DTS). Seven of these smart snake wells have been successfully drilled in Champion West as of April 2006 and three more are planned during the remainder of 2006.

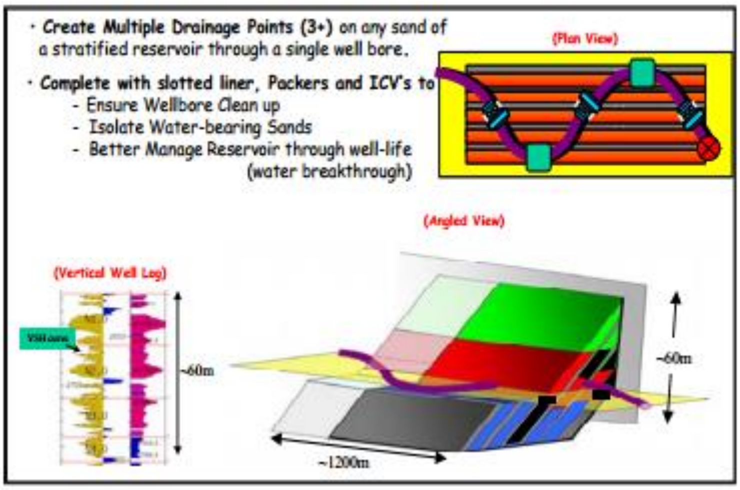

Figure 1: Snake Well Concept. Courtesy: IADC/SPE 114550

FIELD OUTLINE

Champion West Field was discovered in 1975 and is situated approximately 7 Km north-northwest of the Champion Main Field and 10 km north-northeast of the Iron Duke Field. Water depth in the area is around 40 to 47 m.

Champion West Field is characterised by about 1200 m of vertical reservoir sequence distributed over an area of about 40 km in 15 main blocks, with complex and variable fluid distributions including thin oil rims below large gas caps. Close to 100 individual reservoir units occur within each fault block.

Stratigraphically, reserves occur from K1.5 to the T1.0 interval in shore face dominated, mostly fine to very fine grained sandstones of Mid to Late Miocene age that experienced rapid subsidence throughout deposition. The sequence can be divided into a number of distinct columns by thick shales, but even within these columns, thin shales define a number of sub accumulations. Over 28 static pressure cells have been defined up to date.

The reservoir pore pressure in the field increases from hydrostatic in the shallower intervals to almost the deepest interval penetrated. Oil column height varies from 22 m to greater than 300 m in individual reservoirs. The field consists of a series of Wells generally north-northeast to south-southwest trending elongate fault blocks. It is divided into the Outer Blocks and the much more complex Inner Blocks.

The Outer Blocks comprise Blocks 53 to 57; the Inner Blocks are numbered between 41 and 52. The faults that define Inner Blocks mostly dip to the northwest (synthetic) whereas those of the outer Blocks dip to the southeast (antithetic).

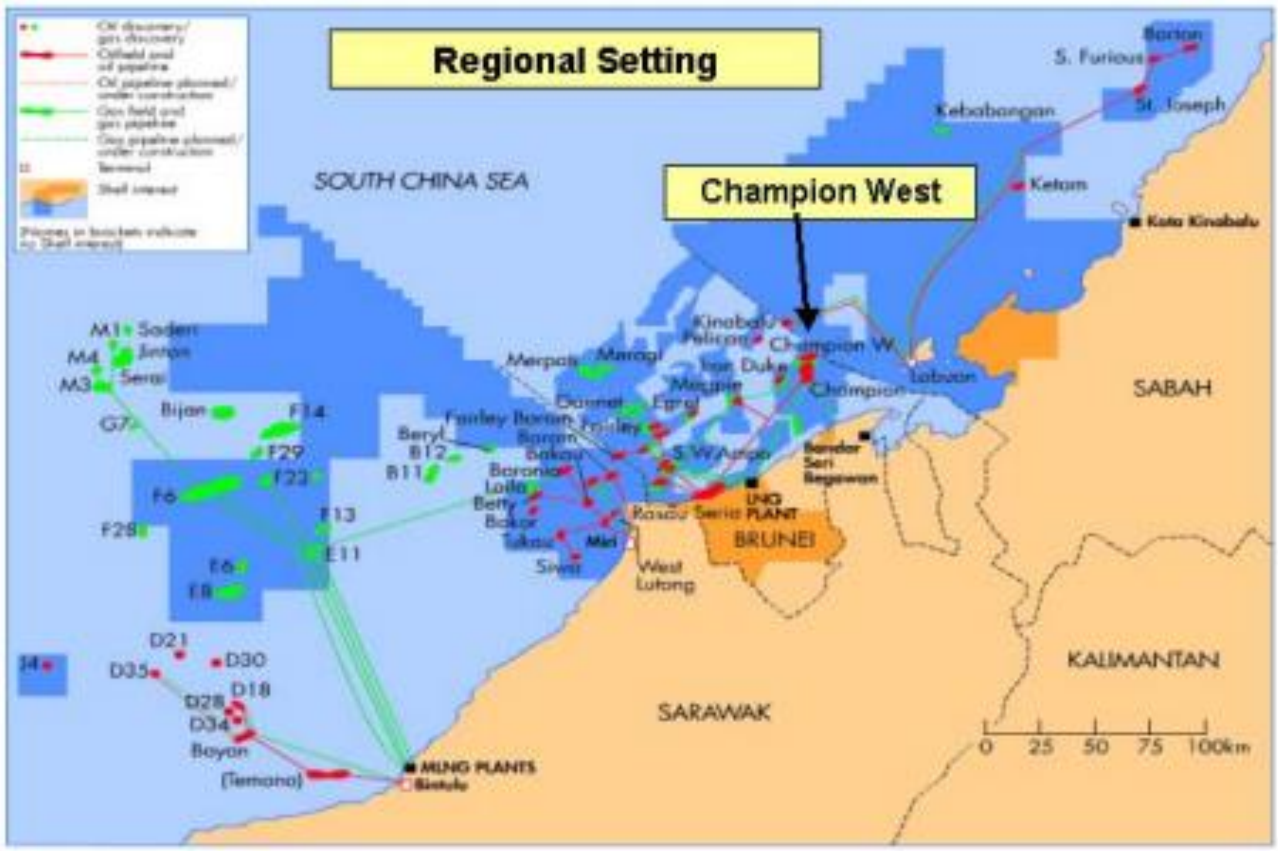

Figure 2: Location of Brunei and Champion West Field. Courtesy: SPE 88524

DEVELOPMENT HISTORY

The Champion West Field was discovered in 1975 by well CP-68. Till October 2004, around 16 wells (13 side-tracks) were drilled. Phase 1 was initiated in 1994 but drilling of the wells turned out to be extremely expensive and complicated and the whole development phase was aborted after drilling 3 of the planned 5 (4 new and 1 side-track) and later development phases were postponed and rescheduled. In 2002, Champion West demanded for another Field Development Plan wherein 6 oil and 2 gas wells were planned in 2003/04. From there, the concepts of snake and intelligent wells were introduced and applied to ensure that FDP objectives were met.

Phase 2 Development (2003-04)

The Phase 2 campaign developed all the reserves that were accessible from then existing infrastructure (*Champion West Well Jackets – CWWJ02 & CWWJ03*) dominantly targeting the Inner Block reservoirs constituting limited undeveloped reserves (Blocks 51, 52, 53). It also included the surface top extension to the well jackets, pilling of new 36” and 30” conductors for single and splitter well heads, installation of Containerized Electrical Room (CER), installation of a new 4.7 km, 8KV subsea power cable, and a 14” High Pressure (HP) multiphase oil line from CWWJ02 to Champion 7 Production Complex. Execution of this phase drilling campaign took place in 2003-04 (6 oil and 2 gas wells),

The snake provided better drainage area and was equivalent to 3-4 horizontal wells and thus, improves the overall ultimate recovery of the reservoir. It outclasses the development concept of multi-laterals and multi-selective fault scoopers wells in the view of Unit Technical Cost (UTC), Recovery Factors (RF), success probability and its completion robustness.

However, snake wells had their own technical limitations and challenges like:

- Potential to exit target zones at inflection points with geological and survey uncertainties while snaking through the horizontal sections.
- Real Time Interpretations.
- Uncertainties of the oil columns, i.e., fluid fills.
- Hole and mud conditions – impairment/washouts of the horizontal sections.

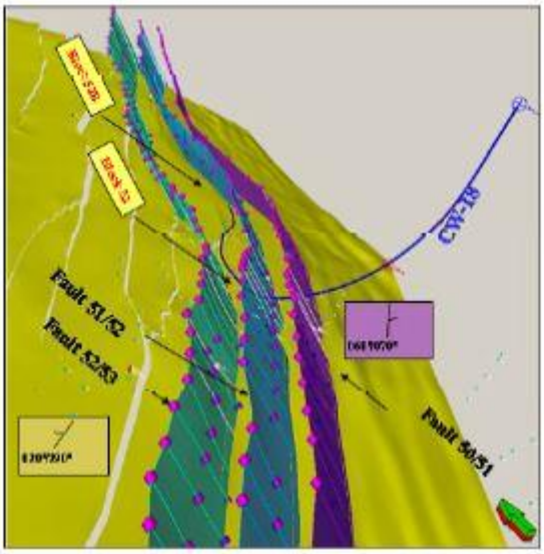

Figure 3: Example of CW-18 Snake Well. Courtesy: SPE 88524

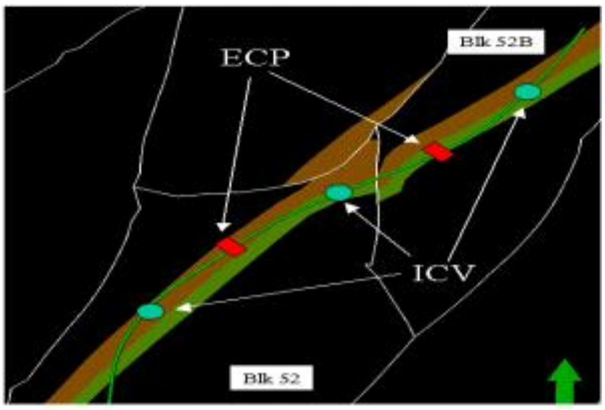

Figure 4: CW-18 Snake well with 3 repeated intersections with the reservoir. Courtesy: SPE 88524

WHY SMART COMPLETIONS?

The rationale for smart completions and the intelligent well concept was initially instituted as many of the long horizontal wells of 2-3 km in length globally fail to produce from the toe from day one and thus, significant production is coming from the heel. It is also known that the drawdown is not well balanced and this brings early water or gas break-through into the system and leaves behind substantial reserves from the midsection to the toe. This phenomena is not acceptable in the Champion West development as it foresees unfriendly water zones while snaking, uncertainty of the oil-gas column, gas break-through at a later life stage and the cost of drilling several short horizontal or multi-laterals are too costly.

In order to cater for the needs of selectivity and an even drawdown and proper well clean-up from heel to toe, the introduction of the so-called innovative "tilted bucket" concept was introduced into the development concept. It was first applied in the Rabi field, Gabon in 1998 where an open ended stinger with a variable choke or fixed sliding side door (SSD) are run into the horizontal sections and thus, clean-up and drain the unproduced segments. Alternatively, the design allows any combination of offtake from 100% from the toe through balanced offtake to 100% at the heel, with consequent control on the drawdown profile illustrates combination of different drawdowns depending on where the stingers and the SSD are located. The overall results were very encouraging.

PLANNED DEVELOPMENT WELL TYPE ("SNAKE WELL")

The combination of the following observations defines the unique development challenges for the target reservoir:

- A long, narrow fault block.
- Steeply north westerly dipping strata.
- The possibility of relatively thin, segregated hydraulic units with different OWC'S.

These considerations led to the realisation that a "snake well" is the ideal well design for the Block 51 N reservoir target. Snake wells are wells that traverse several times through the dipping reservoir in a sinusoidal-like motion, typically in a horizontal plane. The well trajectory "snakes" through a successive dipping layers of sand and shale within the reservoir therefore snake well provide a drainage area and recovery factors that are comparable to those of achieved with multilateral wells, but at a fraction of the cost and technical complexity.

In comparison with conventional horizontal wells, the snake well is the more attractive well design based on Unit Technical Cost (UTC), Recovery Factor (RF) and Ultimate Recoverables (UR); however, critical to the success of a snake well is an accurate static model with well-defined OWC's and GOC's and the ability to steer the well using rotary steering technology.

The inherent risk in drilling a snake well for oil production is to miss the relatively thin reservoir target entirely or in part, or to hit the reservoir target in the water leg, or to drill the well too closely to either the GOC or OWC resulting in reduced oil recovery.

LITERATURE REVIEW

HORIZONTAL WELLS

A horizontal well is defined as a well with an inclination angle of 90 degrees from the vertical. Main function of horizontal drilling is to place a horizontal-hole for a long distance within the pay zone to enhance productivity or injectivity.

In drilling horizontal wells, serious problem appears than drilling a conventional vertical well. Some of these problems are: poor hole cleaning, excessive torque and drag, hole &ling, pipe stuck, wellbore instability, loss of circulation, formation damage etc. So, successful drilling and production of horizontal well depends largely on the fluid used during drilling and completion phases.

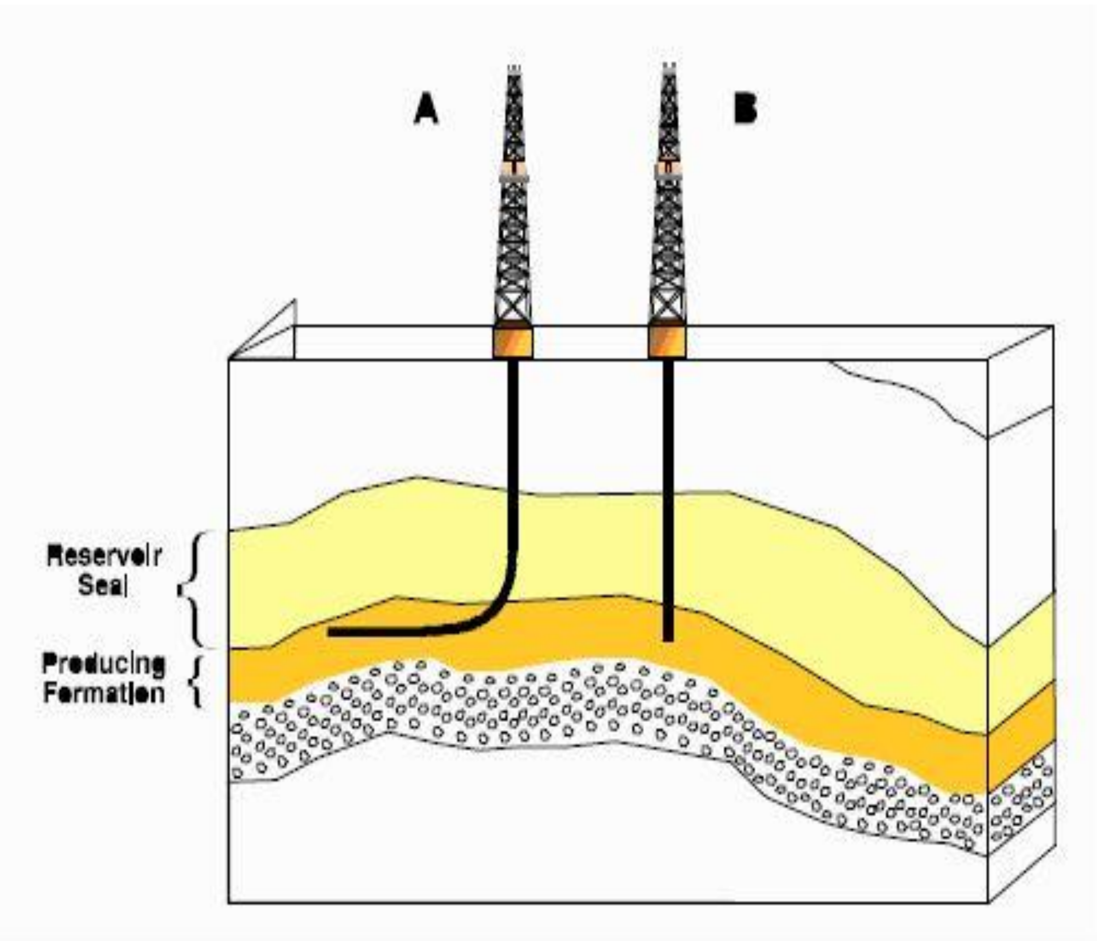

Figure 5: A-Horizontal well and B-Vertical well. Courtesy: Energy Information Administration.

Application of Horizontal Wells

- To produce from naturally fractured reservoirs
- To maximize production from the reservoirs which are not efficiently drained by vertical wells.
- In EOR applications, especially in thermal EOR. A long horizontal well provides a large reservoir contact area and therefore enhances injectivity of an injection well.
- In gas production, horizontal wells can be used in low permeability as well as high permeability reservoirs.

Classification of Horizontal Wells

There are three types of horizontal wells:

1. Short radius
2. Medium radius and
3. Long radius

Short radius Wells (SRW)

The main feature of this type is the very high build-uprate of 60 – 150 degrees /100 ft with a radius range of40-100 ft. This type requires specialized articulated motors to affect the high build angles. Short-radius wells are drilled with specialized drilling tools and techniques.

Advantages

1. Enables sharp turn into thin reservoirs.
2. Both motor driven and drill pipe driven.
3. Laterals can be completed and tied back using special liners.

Disadvantages

1. Limited extension possible.
2. Poor directional control.
3. Special tools and equipment required.

Medium radius Wells (MRW)

The build-up rate for this type is usually 8-30degrees/100ft with a radius range of 200 to 700 ft. The horizontal drain is usually between 1000 – 3500 ft. A typical well profile consists of build-tangent section and a build-horizontal section. Two different BHA’s will therefore be required for this type of well. The second build-up section should ideally start at the top of the "**marker zone"** and should reach a maximum of 85-100 degrees on entry into the reservoir. An angle hold assembly should be used to drill the horizontal section.

Long radius Wells (LRW)

This is the most common type of horizontal wells especially offshore. The build-up rate is usually from 2 to6 degrees/100ft. The most common BHA used is a steerable system containing a single bent sub with a downhole motor. Two profiles are in common use:

- A single build-up section terminating in the horizontal section
- Build-tangent and then a higher build-lateral section.

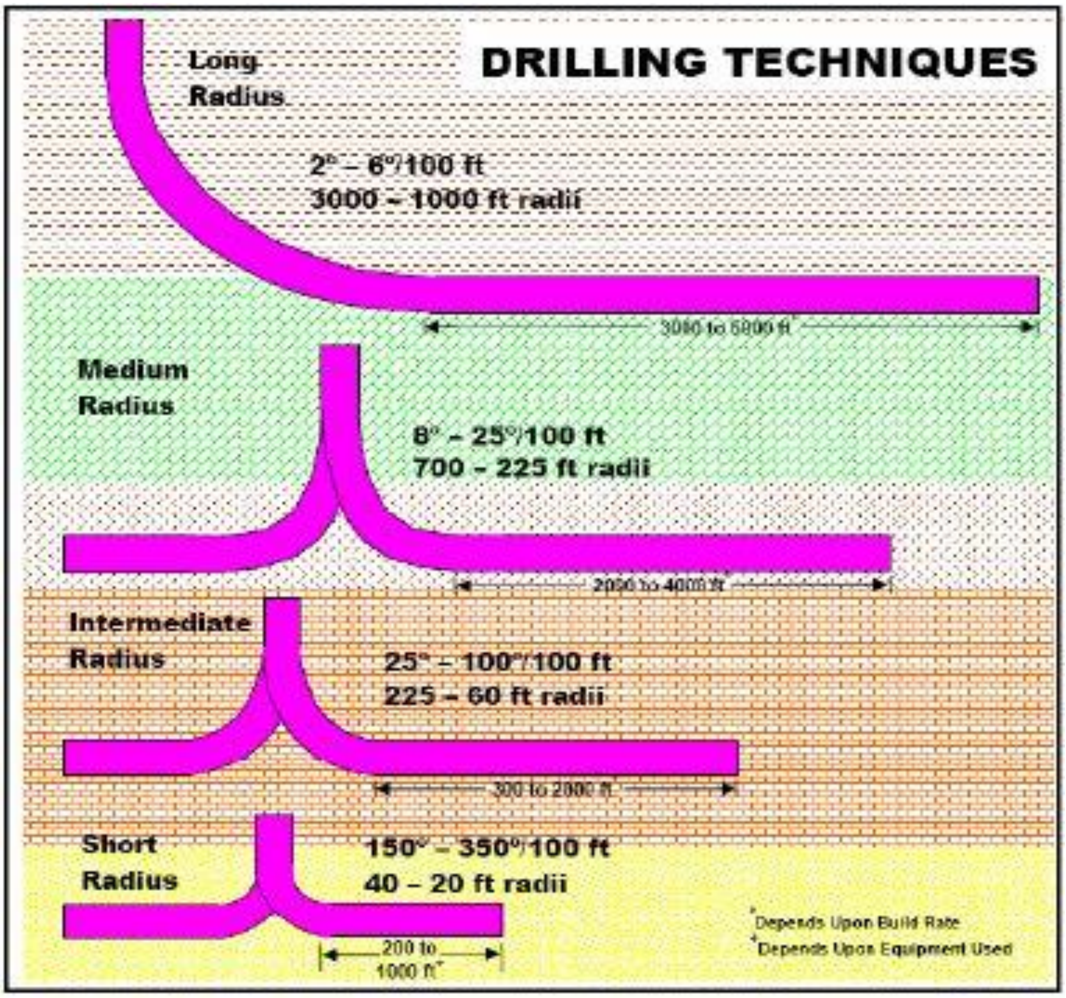

Figure 6: Build curves for short, medium and long radius horizontal wells.

DOG LEG SEVERITY

- It is a measure of the amount of change in the inclination, and/or azimuth of a borehole, usually expressed in degrees per 100 feet of course length. In the metric system, it is usually expressed in degrees per 30 meters or degrees per 10 meters of course length.

- Dogleg severity is high when inclination/ azimuth changes quickly, its low if the changes in inclination are small.
- Equation for calculating dogleg severity using both inclination and azimuth is shown below.

$$DLS = \frac{100}{\Delta MD} \cos^{-1}\{(\sin l_1 \times \sin l_2)[(\sin A_1 \times \sin A_2) + (\cos A_1 \times \cos A_2)] + (\cos l_1 \times \cos l_2)\}$$

Torque and Drag Problems

- One of the major problems associated with doglegs is torque and drag. More severe doglegs will create higher torque and drag.
- Torque will be greater while in tripping or reaming because the collars in this case will be in tension which would increase the overall increase in the drill string.
- Care should be taken when tripping after a significant change in hole inclination and/or direction.
- Assemblies should never be forced to the bottom; they should be reamed to the bottom.
- Torque and drag are caused by the friction between the drill string and the borehole wall. When the drill string is in tension, it tries to straighten while going around a dogleg. The drill string exerts a force on the formation as shown in **Figure 7**. As tension on the drill string increases (depth below dogleg increases) the lateral force increases; therefore, the torque and drag increase.

Reducing Torque and Drag

Torque and drag can be reduced by several different means:

- Keep DLS low. Although it would decrease the effect only by a small amount.
- Torque and drag can be reduced using lubricants in the mud system. Oil and other commercially available lubricants reduce the coefficient of friction between the drill string and borehole wall; thereby, reducing the torque and drag.
- Another method is to reduce the tension in the drill string. This can be accomplished by removing excess collars, or replacing the collar with heavy-weight drill pipe. The heavy-weight drill pipe is more flexible and reduces the overall string weight while maintaining the same.

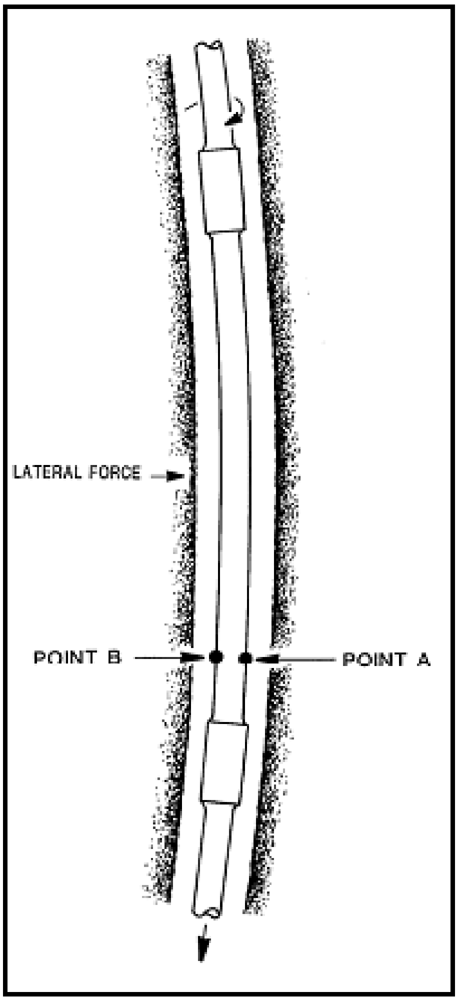

Figure 7: Bending of Drill Pipe in a Dogleg, Rotation Causes Cyclic Stress Reversals. Courtesy: Richard S. & Robert D. - Directional Horizontal Drilling Manual - PetroSkills.

EQUIVALENT CIRCULATING DENSITY

The ECD can be defined as the additional mud weight seen by the hole, due to the circulating pressure losses of the fluid in the annulus. When the drilling fluid is circulating through the drillstring, the borehole pressure at the bottom of the annulus will be greater than the hydrostatic pressure of the mud, this extra pressure is due to the frictional pressure required to pump the fluid up the annulus. This frictional pressure must be added to hydrostatic pressure to get a true value of the pressure acting against the formation at the bottom of well. The ECD is affected by annular pressure loss which is affected by Flow rate, Mud Rheology, RPM, Surge & Swab pressure.

ECD [ppg] = **MW [ppg]** + **Annulus ΔP [psi]** / **(0.052 TVD [ft])**

ECD = Equivalent Circulate Density
MW = Mud Weight

Annulus ΔP = Annular Pressure Losses
TVD = True Vertical Depth

ECD impacts

- High ECD increases the risk of lost circulation, while running or circulating long casing string.
- Wellbore instability can be caused by the constant flexing and relaxing of the wellbore when pumps are turned on and off. Effectively, the wellbore will fail through fatigue. An indirect effect will be impact on hole cleaning if losses are encountered due to the ECD, in effort to reduce losses, flow rates will be reduced, allows build up the cuttings in hole, resulting in a poor hole cleaning.

OIL BASED MUDS

An oil based mud system is one in which the continuous phase of a drilling fluid is oil. When water is added as the discontinuous phase then it is called an invert emulsion. These fluids are particularly useful in drilling production zones, shales and other water sensitive formations, as clays do not hydrate or swell in oil. They are also useful in drilling high angle/horizontal wells because of their superior lubricating properties and low friction values between the steel and formation which result in reduced torque and drag. Invert emulsion fluids (IEFs) are more cost-effective than water mud in the following situations:

• Shale stability, Temperature stability, Lubricity
• Corrosion resistance, stuck pipe prevention, Contamination and Production protection

There are two types of oil based mud:
• **Invert Emulsion Oil Muds**
• **Pseudo Oil Based Mud**

INVERT EMULSION OIL MUD

The basic components of a typical low toxicity invert emulsion fluid are:

Base Oil: Only low toxic base oil should be used as this is the external emulsion phase.

Water: Internal emulsion phase. This gives the Oil/Water Ratio (OWR), the% of each part as a total of the liquid phase. Generally, a higher OWR is used for drilling troublesome formations. The salinity of the water phase can be controlled by the use of dissolved salts, usually calcium chloride. Control of salinity in invert oil muds is necessary to “tie-up” free water molecules and prevents any water migration between the mud and the open formation such as shales.

Emulsifier: Often divided into primary and secondary emulsifiers. These act at the interface between the oil and the water droplets. Emulsifier levels are held in excess to act against possible water and solid contamination.

Wetting Agent: This is a high concentration emulsifier used especially in high density fluids to oil wet all the solids. If solids become water wet they will not be suspended in the fluid, and would settle out of the system.

Organophillic Clay: These are clays treated to react and hydrate in the presence of oil. They react with oil to give both suspension and viscosity characteristics.

Lime: Lime is the primary ingredient necessary for reaction with the emulsifiers to developthe oil water interface. It is also useful in combating acidic gases such as CO_2 and H_2S. Theconcentration of lime is usually held in excess of 2 to 6 ppb, depending on conditions.

PSEUDO OIL BASED MUD

By considering the environmental problem of low toxicity oil based muds and their low biodegradability, developments have been made in producing a biodegradable synthetic base oil. A system which uses synthetic base oil is called a Pseudo Oil Based Mud (SOB) and is designed to behave as close as possible to low toxic oil based mud (LTOBM). It is built in a fashion akin to normal oil based fluids, utilising modified emulsifiers. SOB muds are an expensive systems and should only be considered in drilling hole sections that cannot be drilled using water based muds without the risk of compromising the well objectives.

The base oil that is being changed out can be one of the following:

Detergent Alkalates, Synthetic Hydrocarbon, Ether and Ester: These have been listed in increasing order of cost, biodegradability and instability. Synthetic base fluids include Linear Alpha Olefins (LAO), Isomerised Olefins (IO), and normal alkanes. Other synthetic base fluids have been developed and discarded such as ethers and benzene based formulations. Esters are non-petroleum oils and are derived from vegetable oils. They contain no aromatics or petroleum-derived hydrocarbons. The primary advantage of an ester-based fluid is that it biodegrades readily, either aerobically or, more importantly, from a mud cuttings disposal viewpoint, anaerobically.

HOLE CLEANING

Hole cleaning in vertical wells is different than in directional wells. In vertical wells there are a number of mathematical. models to describe hole cleaning or lifting capacity. In these models, all particles with a density higher than the mud weight will have a tendency to fall through the drilling fluid and the rate at which the particle falls is termed the slip velocity. The slip velocity of a particle is a function of the diameter of the particle, the density difference between the mud and particle and the viscosity of the drilling fluid. Smaller diameter particles are easier to clean from the hole. By increasing the mud weight, the density difference becomes smaller and the lifting capacity of the drilling fluid increases. Increasing the viscosity of the mud will also increase the lifting capacity.

In a vertical well, the particle velocity (V_p) is the difference between the fluid velocity (V_f) and the slip velocity (V_s) as shown in Figure 6-16. So long as the fluid velocity exceeds the slip velocity, the drill cutting will travel up the wellbore and out of the hole. If the fluid velocity is equal to or less than the slip velocity, then the cutting will stay in the well. This is mathematically shown in the following equation.

$$V_p = V_f - V_s$$

Equation 1

In directional wells, the previously mentioned empirical correlations cannot be used. As shown
in **Figure 8**, the particle velocity is the resultant of the slip velocity and the fluid velocity. The slip velocity is always vertical whereas the mud velocity is parallel to the axis of the hole. It is evident that the particle will eventually find its way to the low side of the hole.

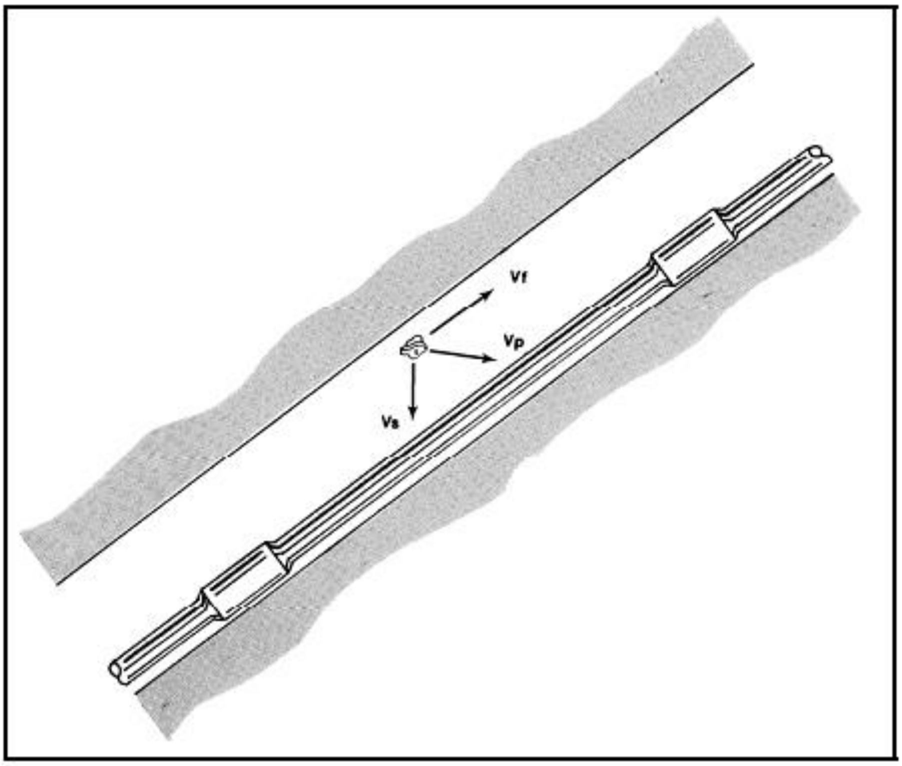

Figure 8: Particle Velocity in an inclined wellbore

The cuttings will eventually form a cuttings bed on the low side of the hole, when the inclination is high enough. Once the particle is a part of a cuttings bed, then the particle velocity is no longer simply a function of the slip velocity and the fluid velocity. Without pipe movement, the fluid in the annulus will have to erode the cuttings bed in order to carry the cuttings up the hole. In a directional well, the cuttings will form a bed on the low side of the hole. The bed will continue to grow narrowing the annular space and causing an increase in the annular velocity. The annular velocity will increase to the point where the cuttings bed is being eroded as fast is it is being deposited. At this point, the bed height reaches equilibrium.

HOLE CLEANING PROBLEMS ASSOCIATED WITH INCLINATION

The hole cleaning problems in a directional well are a function of the inclination. Certain inclinations are worse than others and the variation in problems generally occurs over specific ranges of inclination. Therefore, hole cleaning will be discussed over these specific ranges.

0° to 10°

For all intents and purposes, wells with inclinations between 0° and 10° behave the same as vertical wells. The methods discussed in References 3 through 5 can be used to determine hole cleaning capacity.

10° to 30°

At velocities less than 120 fpm, the cuttings will settle to the low side of the hole and slide down the wellbore. Within a short distance, they will again end up in the higher velocity portions of the annulus and be carried up the hole. The phenomenon is continuously repeated until the cuttings are carried out of the hole. In general, the hole cleaning capacity of the mud at this inclination is not as efficient as vertical wells; however, it is usually satisfactory. This assumes that the lifting capacity of the mud is high enough to lift cuttings out of the hole in a vertical well.

At annular velocities above 120 fpm, the cuttings are not able to form a bed on the low side of the hole, but rather are carried up the wellbore along the low side in slugs or dunes. At flow rates in excess of 180 fpm, the cuttings are carried smoothly along the low side of the hole.

Figure 9 is a plot of total cuttings concentration versus wellbore inclination adopted from data published by Tomren et al. [6] The total cuttings concentration is a measure of the hole cleaning efficiency. The lower the number, the better the hole cleaning. Note that for a vertical well, the total cuttings concentration ranges from one to five and there is little change up to 10°. From 10° to 30°, the hole cleaning efficiency decreases especially at lower annular velocities.

30° to 60°

Hole cleaning is the most critical at inclinations between 30° and 60° with the inclinations between 40° and 50° being the most difficult. **Figure 2** shows that the largest buildup of cuttings in the wellbore occurs over these inclinations. In experiments performed by **Tomren,** a cuttings bed formed at 40° with an annular velocity less than 150 fpm. At 50°, a bed would form at annular velocities of 180 fpm.

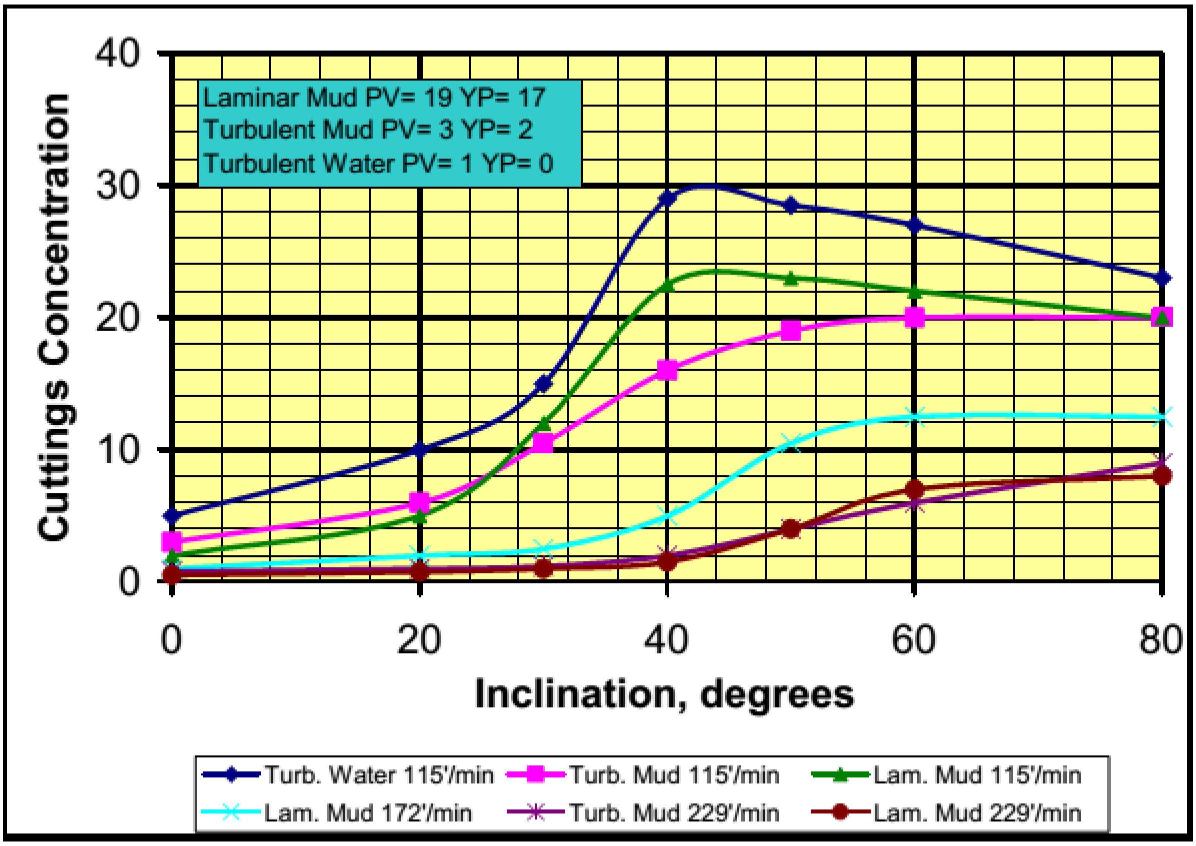

Figure 9: Graph Showing the Effects of Inclination on Hole Cleaning Efficiency. Courtesy: Tomren, P.H., Iyoho, A.W., and Azar, J.J.; "Experimental Study of Cuttings Transport in Directional Wells," SPE Drilling Engineering, Feb 1986, pp. 43-56.

Experimental studies by **Zamora and Hanson** also revealed that this was the critical inclination for hole cleaning. Not only can a cuttings bed form rapidly at these inclinations, but the cuttings slide down the wellbore on the low side of the hole. The drag forces associated with the drilling fluid traveling past the bed tends to reduce the rate at which the cuttings will slide down the wellbore. However when the pump is turned off, the drag forces no longer exist and the cuttings will then slide down the wellbore more readily. The cuttings can pack off around the drill string causing excessive torque and drag or a stuck drill string. This phenomenon is shown in **Figure 10**. The cuttings will slide down the wellbore until they reach the bottom or until the inclination is high enough where the cuttings will no longer fall to bottom. The maximum inclination is a function of the type of drilling fluid and roughness of the wellbore, but it will be generally between 55° to 70°.

In directional wells with inclinations less than 40°, the cuttings will fall to the bottom of the hole. Poor hole cleaning will be evidenced by fill on bottom. In high inclination or horizontal wells, the cuttings will fall to a maximum inclination. Poor hole cleaning will be evidenced by excessive drag while pulling the bottom hole assembly through the section where the cuttings quit falling. While tripping in the hole, bridges will be encountered in this section. In these types of wells, cuttings do not fall to bottom; they fall to the low side of the hole and slide down until the inclination reaches a critical value.

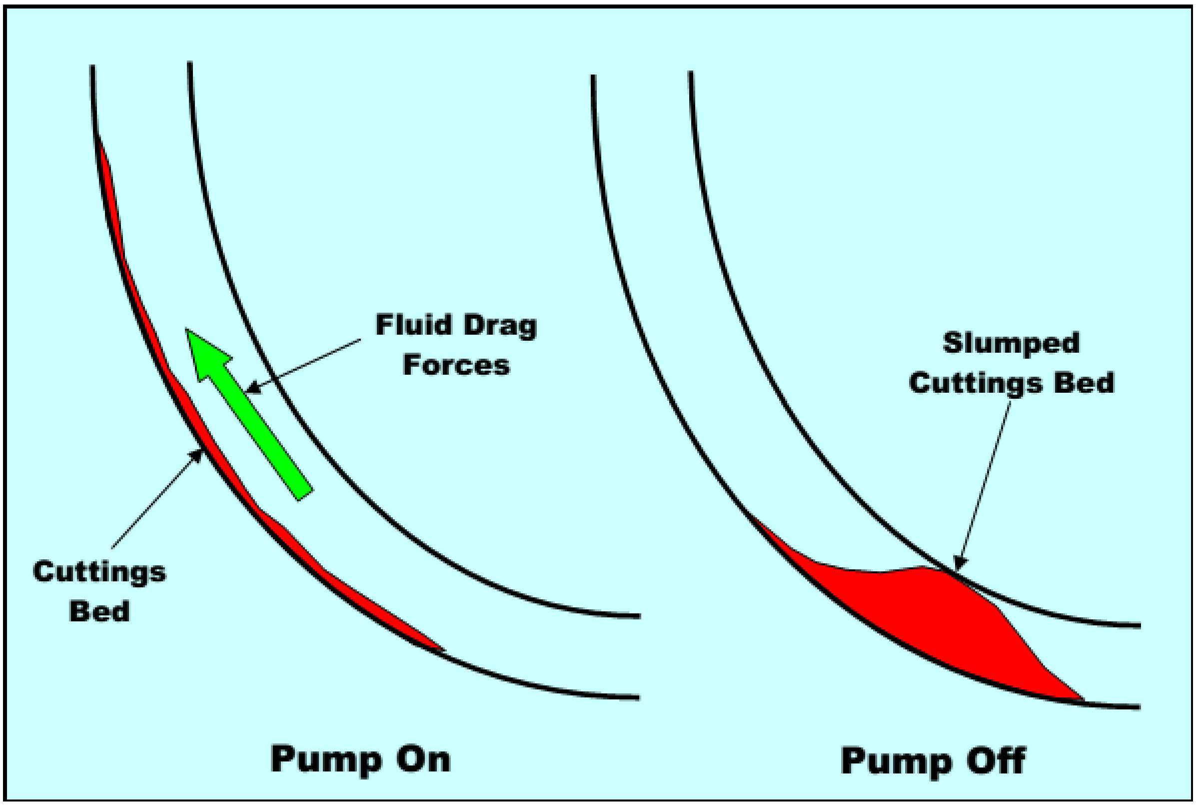

Figure 10: Cutting Bed Slumping When the Pump is Turned Off. Courtesy: Richard S. & Robert D. - Directional Horizontal Drilling Manual - PetroSkills.

60° to 90°

Above an inclination of 60°, cuttings bed development does not get any worse. At some lower annular velocities, the volume of cuttings in the well actually reduces as can be seen in **Figure 7**. Above 60°, the cuttings do not slide down the low side of the hole which reduces the total volume in this section of the wellbore. A cuttings bed will build up reducing the annular area which increases the annular velocity. As the annular velocity increases, the drilling fluid will erode the bed faster. At some point, equilibrium will be reached between the deposition and erosion of the cuttings bed.

ANNULAR VELOCITY

Annular velocity is the variable that will affect hole cleaning the most. A increase in annular velocity decreases the size of the cuttings bed formed on the low side of the hole & in some cases may prevent it. The three flow rates shown in **Figure 6** are 115, 172, and 229 fpm. Each increase in annular velocity shows a corresponding decrease in the total cuttings concentration. Even when a cuttings bed is formed, the annular velocity increases and the bed is eroded until the system is in equilibrium as explained earlier.

DRILLING AND COMPLETION PRACTICES ADOPTED FOR SNAKE WELLS

TRAJECTORY CONSIDERATIONS FOR SNAKE WELLS

Meeting the design objectives requires a high level of work on the well design, specifically trajectory planning. Fulfilling both geologic and drilling focus process to ensure all objectives were met. The highly requirements resulted in an iterative compartmentalized nature of the field drove the requirement of striking several sand packages, extending the section length through lateral azimuthal changes while drilling through dipping reservoirs, and avoiding fault blocks. Upon satisfying the geologic criteria, the trajectory was run through an extensive torque and drag and hydraulic analysis.

Dogleg severity (DLS) and cumulative tortuosity were paramount in the planning stage as they would dictate expect reservoir course length or reach when estimating surface torque, over pull margin and available weight transfer. DLS also had implications on trippability of the drill string and BHA through dipping reservoirs. From the design stage analysis a DLS maximum criterion of 1^{o}/ 10 m was set as the optimal upper end yield to stay within the allowed operating envelope.

Due to the long trajectories of the snake wells, the theoretical pipe stretch and drill string wraps were identified as potential operational obstacles to overcome during the drilling phase. As a result, pipe stretch and wraps were modelled and connection practices were evaluated, ultimately developing operating procedures to drill in singles in case of excessive actual stretch recorded (>6m). Even at moderate stretch figures of 4-5 m connections could not be made off bottom. In the $8\frac{1}{2}^{"}$ hole section it proved to be important to back ream as high as possible before a connection, thereby leaving enough room to set down stretch after a connection. Off-bottom parameters had to picked carefully as the contrasts in torque and hook load become less with the extent of the horizontal open hole section. At the same time, there were hydraulic issues to overcome related to pressure variations and hole cleaning.

WELL TRAJECTORY AND DLS LIMITATION IN SNAKE WELLS

Formation pressures for the CW Phase 3a oil wells were mostly just above hydrostatic resulting in maximum drilling mud weight of 13.0 kPa/m and 3,500 psi CITHP. A typical pore pressure prediction for the CW field can be seen in **the figure below**.

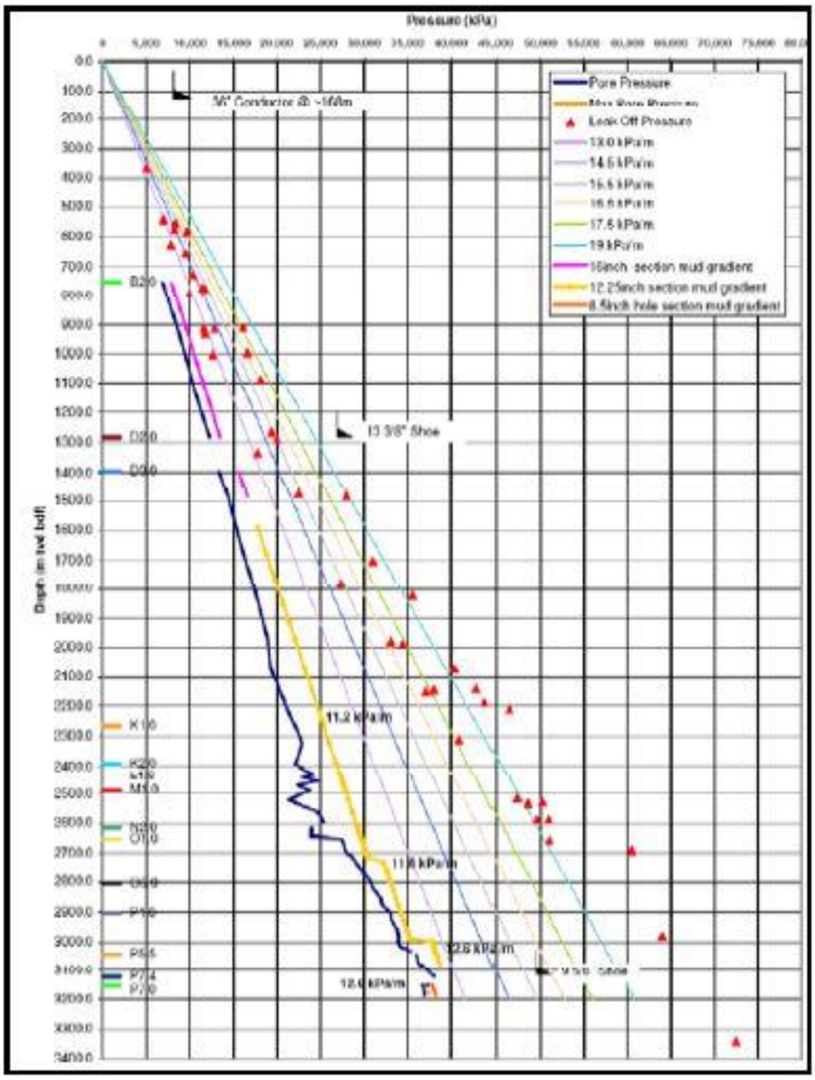

Figure 11: CW-D Generic Pore Pressure Plot. Courtesy: IADC/SPE 114550

- The casing design is simple, with the objective of landing the 9-5/8" casing shoe just inside the target reservoir at 90^o inclination.
- The reservoir consists of consolidated sands that do not require sand control equipment. Therefore, a pre-drilled 7" liner is run to keep a clear conduit for the SMART completion. Where required, blank pipe sections, combined with external swelling packers, achieved zonal isolation for reservoir management. Seal bores and later swell able seal assemblies provided isolation on the completion side.
- The well trajectory had to be designed as smooth as possible in order achieve the planned tums within the wellbore length. The casing shoe had to be landed in a particular orientation to allow the designed number of hinge points to be drilled through the horizontal reservoir section.
- The hinge points were positioned to maximize the number of drainage points along the reservoir structure. The dogleg severity of the trajectory was controlled at **maximum 1^o/10m** to avoid increasing torque and drag.

- High drag and torque close to the TDS-8 maximum torque capability meant that the maximum number of hinge points had to be limited.

ADT

- During drilling of these wells, valuable monitoring and technical support was provided by the Advanced Drilling Technology (ADT) centre (ADT is a trademark of Halliburton).
- The ADT capability consists of data reception of all RSS (Rotary Steerable System) information to the BSP office via network or satellite links. Data is analysed and prioritised, and the feedback given to the rig with traffic lights and roadmaps. This real-time capability was monitored 24/7 from the central BSP office. The information in real time was also through Internet. Torque and Drag Roadmaps were generated and real-time warning flags were offered to the rig according to an agreed communication protocol.
- The ADT feedback on stick-slip and vibration helped the team to evolve BHA (Bottom Hole Assemblies) that resulted in longer runs and prolonged bit life. Additional engineering support such as hydraulics, ECD management and many others are also available from the ADT centre.
- The ADT service offers a menu of engineering support programs to the Drilling Superintendent and operation Engineer.

MUD SYSTEM

- The mud program was based on a bentonite-polymer system up to the 13-3/8" casing and then an Isomerised olefins (IO) based system for the 12-1/4" and 8-1/2" sections. The IO system has proven to be an excellent choice for these applications, due to the stability of the rheology under high temperatures and high flow rates.
- Due to a maximum through-bore of the splitter wellhead system of 14.495" ID, the top hole of the wells was drilled with 8-1/2" pilot bit using a motor with 1.15^{o} bent housing to achieve the directional objectives. The pilot hole was then opened up to 16" with the use of eccentric reamers.
- The 16" hole section did not present many problems except for severe clay balling in the shallower parts of some wells. Balling was dealt with the dilution and dumping, maintaining the MW below 10.5 kPa/m and the sand content below 1%.

BHA SELECTION AND HARD STINGERS

- While drilling the 12" section, hard stringers were frequently encountered. Procedures to drill through the hard stringers were developed through experience. Whenever a sudden decrease in ROP was experienced, the flow rate was reduced to prevent washing the formation around the stringer. The RPM was lowered while maintaining the WOB. The vibrations induced while drilling the hard stringers were also monitored closely by the ADT centre, and warnings were issued to the drilling team offshore with suggested modified parameters to minimize the vibrations.
- Once the bit was fully embedded in the hard formation the WOB was stepped up, maintaining the RPM and the flow. Once the bit was exiting the hard stringer, ROP would increase and parameter fluctuations might occur. The flow was maintained low to prevent wash out under the hard stringer, while the WOB was allowed to drill off to some degree. Once the bit fully exited the hard stringer the parameters would be adjusted again. However, exiting the hard stringer was sometimes more complicated than entering it due to lateral vibrations and the sudden increase in ROP. These effects could cause a ledge because part of the bit was still drilling the hard formation while the bottom pattern was destroyed as the bit may be hanging on the ledge.
- Seven bladed long gauge bit designs were selected to drill these extended sections. A new cutter technology with a combination of 16 mm and 13 mm cutters helped to prolong bit life and thereby to minimise bit trips compared to previous phases of the CW project.
- The addition of roller-reamers and shock-subs in the assemblies greatly reduced the vibrations and lateral shocks.
- The amount of HWDP below the jar in the 8-1/2" section was tailored to reduce vibration and increase the weight transfer. Seven bladed bits with 13 mm cutters were selected for the 8-1/2" sections. The stick-slip was minimized with this design resulting in longer nuns and better protection for the bit Long gauge and smooth profiles were selected as opposed aggressive high performing bits.

HOLE CLEANING AND UNDER REAMING

- Detailed training, observation and experience led to the development of guidelines for hole cleaning, tripping and drilling in ERD conditions. The required ERD training included all of the execution/planning team, together with the relevant third parties.

- An independent ERD expert visited BSP several times, peer-reviewed the programs and offered valuable input during the planning stage.
- The 8-1/2" sections presented the most difficult challenges. These sections were drilled using Rotary Steerable systems in combination with an under-reamer (UR) that opened the hole to 9”.
- The preferred UR used in CW was flow activated with a drop ball system for back up.
- By opening the 8-1/2" hole to 9" the following objectives were met:
    - The assemblies could be tripped on elevators
    - ECD was lower at higher flow rates
    - The 7" slotted liner with swell able packers could be used without compromising the completion objectives for zonal isolation.

ECD MANAGEMENT

- Equivalent Circulating Density (ECD) management was a critical issue as the well had to be cleaned up at high flow rates. ECD control and management was monitored real-time by the ADT centre.
- The use of fresh mud resulted in a larger operational envelope with respect to SPP (Stand Pipe Pressure) and ECD when compared to aging or old mud with higher colloidal solids content. Fine mesh screens were used to remove sand and centrifuges to remove low gravity solids.
- Hole cleaning at section TD or prior to trips was performed with minimum 4-5 bottoms-up circulations, staging out one stand every 30 minutes, while observing for the 2nd wave of cuttings.
- Strict discipline in hole cleaning and tripping practices resulted in minimal back-reaming requirements.
- Reaming on connections was limited to one single only, unless the roadmaps showed a requirement to ream the whole stand. Controlling the ROP to 25-30 m/hr. in the last part of the horizontal section increased the chances of having a clean hole prior to the trip.
- Whenever the wells were circulated, the base plan was to pick up the string slowly with 50-60 rpm (to prevent pack offs) and to lower the string at 120 rpm or more with 30-45 min stand. However, parameters were often adjusted to minimize the down-hole vibration.
- Back-reaming would be considered, but only as a last resort whenever the tightness of the hole would not be related to hole cleaning. Also, the back-reaming parameters were clearly specified to prevent packing off, losses or stuck string. However, in holes with large azimuth turn, light rotation and flow rate were sometimes used to come out of the hole.

- The mud log was available to the driller to check if tight spots were related to cutting beds or were formation related. The maximum over-pull was limited to 15 kdaN before circulation was commenced.

PRE-DRILLED LINER

- Before the long sections of pre-drilled liner were run into the well, it was critical check-trip assembly could be pulled smoothly on elevators, as this would confirm that the hole was as clean as required for trouble free liner installation. The minimisation of DLS (dog leg severity) throughout the well path also helped in achieving smoother runs of the liner.
- All pre-drilled liners had high torque connections because in most cases they had to be rotated to depth. Simulations indicated that the liner could be run on elevators to 7000 m with a FF of 0.25 but often it bad to be rotated at shallower depths.
- In addition to the torque reduction capability, the Non-Rotating Drill Pipe Protectors also provided additional stiffness to the string, allowing more weight transfer from the HWDP to the liner before the onset of buckling.
- As the liner was run in hole to the previous casing shoe drag data was recorded and plotted against the model. This served as a last calibration of the drag model before the liner went into the open hole.
- The centralisation programme for the liner was also constantly revised as experience was gathered and ultimately the spacing of one solid centralizer every two (slick) joints provided enough torque reduction and all standoff.
- The use of solid spiral body centralizers was preferred compared to the roller centralizers, which were tested at the beginning of the campaign. The centralisers were allowed to float at least 2-3 metres between stop collars.
- The swellable packers that were recovered after an aborted liner operation showed little damage caused by rotation.

PROBLEMS FACED AND THEIR MITIGATION

BOTTOM HOLE ASSEMBLY – DESIGN AND REDESIGN

The BHA was planned with uttermost care and future predictions, but some unseen problems could never be ruled out of the scenario. Problems like stuck ups while tripping, hole cleaning, hole caving were often experienced. Hence, the entire BHA had to be redesigned in order to mitigate them.

PROBLEMS WITH THE ORIGINAL DESIGN

The main issues that were identified are –

- There was narrow margins between Equivalent Circulating Density (ECD) and fracture gradient.
- String vibrations
- Stick/ Slip causing below par drilling performance leading to an increase in tool failure frequency.
- Hole cleaning to drill to Total Depth (TD) was a major issue as the BHA had to trip out of the hole and run the subsequent casing/ liner string without getting stuck.

In the previous wells the BHA component failures were often related to significant string vibrations caused during drilling and mainly during back reaming operations. Significantly for this reason a more stabilised design had to be chosen but a well stabilised BHA tends to reduce the flexibility of the string which in turn will cause more difficulties during tripping out of the hole especially along the tortuous well paths.

Hence, with a stabilised design, it was clear that the BHA could only be back reamed out of the hole because the level of hole cleaning required to get this BHA out of the ground was not achievable within pumping rates and ECD windows.

Also the point the bit rotary steerable system (RSS) in use did not facilitate either, as it came with a long gauge bit and almost full sleeve right behind the bit which reduced the flexibility even further.

In addition to the string stabilisation, reaming while drilling tools have been incorporated in the string to reduce the ECD. The tools were positioned above the logging while drilling tool collars and performed well with respect to their hole enlargement success rate. However they led to a secondary cutting vibrations which led to additional vibrations especially in case of drilling through sequences of interbedded sand and shale. These sequence are associated with hard stingers which cause resistance to the reamer and at this stage will cause it to hang up and generate stick/ slip therefore, that prevents efficient weight transmission to and drilling progress at the bit.

As the tool failure was encountered and the increased risk of stuck pipe, especially past the predicted buckling point, it became standard practice to plan a dedicated round trip half-way to layout the radioactive source which infers that the reservoir section could not be fully logged to total depth.

Based on the above observations BSP decided to redesign a new BHA to mitigate the key risks based on the following –

- Employ a more flexible, shorter and slicker BHA
- Allow for a triple combo LWD data acquisition
- Avoid or limit high intensity back reaming
- Achieve overall high drilling progress to beat the top quartile performance targets.

BHA REDESIGN

Main goal of BSP was to design a more flexible, slim and short BHA which would be better capable of drilling to TD along with tortuous trajectory and most importantly it could be tripped out of the hole without heavy back reaming required hence, reducing the Lost In Hole risk and subsequent non-productive time (NPT).

The new BHA was based on **one-collar LWD concept** which allows for minimum stabilisation requirement and reduces its overall length by **10 m** from bit to crossover and to the HWDP.

The main change in BHA was **"Drill Collars have been omitted as much as possible."** The main advantages of omitting drill collars are as follows:

- HWDP connections are less prone to fatigue failures than drill collar connections.
- HWDP results in less ECD due to the larger annular clearance.
- Rig handling of HWDP is faster and safer.
- HWDP results in less internal pressure drop.
- HWDP assemblies are lighter which results for reduction in drag therefore, less stick/ slip and improved tool face control.

According to BSP, the best practice in these wells to run is –

- 19*HWDP above the crossover
- 7*HWDP above the jar
- 2*HWDP above the accelerator

Drilling Jar run in horizontal section must be capable of being run in compression. This requires a weight on bit (WOB) range to avoid shifting the neutral point across the jars during drilling.

The new design also had point – the – bit RSS BHA to allow for superior steering capability even in softer formations and ensure sufficient hole cleaning. Stabilisers on the RSS were hard faced with **Tungsten Carbide** tile to increase the longevity and durability.

Another main concern was to get logging data till total depth. This was taken care by reducing the BHA length, a multi-function LWD tool that housed measurements in one 8-m drill collar which was moved above the MWD tool to space out the stabilisers and increase the BHA flexibility.

To further increase the stability of BHA an under gauge hole conditioning integral blade stabilizers was positioned above the LWD tool.

So, after the completion of BHA configuration, the next aim was to select the bit which could undergo impact/ vibration damage. Considering the factors, a **heavy set six-bladed bit** with backup row and depth-of-cut feature was considered appropriate for interbedded, hard formations with long course lengths.

REDESIGN PERFORMANCE RESULTS

The redesigned BHA provided better results and was successful in several ways-

- A performance increase of 38% was observed in $12\frac{1}{4}''$ hole sections.
- A performance increase of 31% was seen in $8\frac{1}{2}''$ hole sections.
- Due to shorter well durations there was a significant cost saving.
- Acceleration first oil by saving on drilling time.
- No requirements to limit ROP to ensure high quality LWD sampling rate.
- No hole deteriorations due to excessive back-reaming at high parameters.
- Significantly lower vibrations throughout all the runs avoiding damage to BHA components and high repair costs.
- Reduced need for intermediate trips in reservoir to lay out radioactive source prior to buckling point.
- Increased upfront and post-well engineering support with the goal to constantly improve performance.

PROBLEMS PRESISTING AFTER REDESIGN

1. HOLE INSTABILITY

The cavings were identified with angular shape which signified underbalanced conditions and were generally seen after several hours of drilling through the shale section. It was also noticed that during drilling through the shale section the hole was not of circular shape and radius of the well was 1'' or 2'' more than that of the well size and none of that was observed in the sandstone formation. So it was discovered that the formation with shale layers are not compact and shale sloughing was a major problem.

Figure 12 below shows the cross section of wellbore from sand (left) and shale (right). The black line represents the hole shape and green line the bit size and blue shading represents the nominal BHA collar.

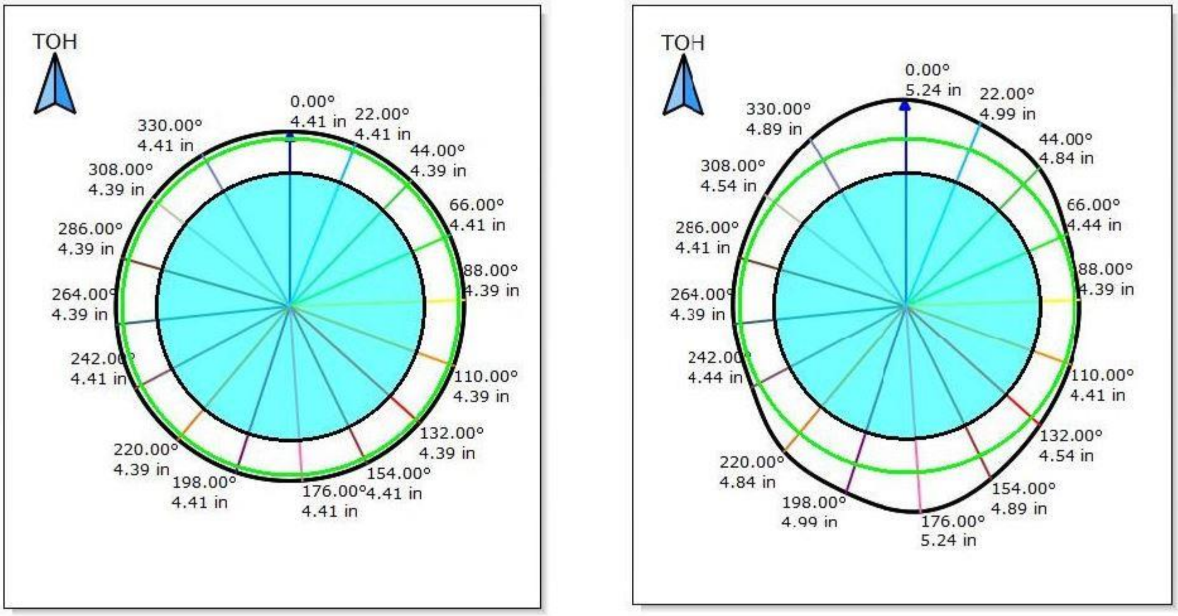

Figure 12: Diagram showing cross section from sand(left) and shale(right).

2. HOLE CLEANING

Hole cleaning was another big issue while drilling a well with such a complex geometry. BHA of such a stabilized design was used and it was clear that it could only be back reamed out of the hole. It was mainly due to the reason that the level of hole cleaning required to get that BHA out of the hole was not achievable within pumping rates and ECD windows.

Also the cuttings were quickly accumulated across the stabilised zones and caused pack offs.

3. ECD MANAGEMENT

By seeing the nature of hole instability it can be said that insufficient mud weight was the problem. Hence, stricter mud properties management was required. With the pressure variation already considerable, the increase in mud weight would also further increase the down hole formation stresses. Therefore, proper mud properties must be chosen with sufficient mud weight to eliminate the problem of hole instability.

MITIGATION OF ABOVE PROBLEMS

A detailed study was made for the above mentioned problems and there were similar cases in other fields mainly in U.S. which had the same issues while drilling through the shale formations. There also extended reach horizontal wells were drilled and they had the problems of hole instability and hole cleaning issues.

In North Sea two wells were drilled with especially designed polymer drilling fluid to provide for optimum shale and borehole stabilisation.

In deeper wells, high temperature polymer additives were used to maintain favourable rheological and filtration properties. In that reservoir several hole problems were encountered which includes **sloughing shale, hole fill, differential sticking and logging problems**. These were the same problems as associated with the Offshore Brunei.

The **PVA/ Potassium Silicate** shale stabilizing additive was used for the troublesome sections and the result was minimum hole problems were experienced.

In North America, during the last few years' shale drilling for both natural gas and hydrocarbon liquids has increased dramatically. The typical wells in the Bakken Shale are 17,000 ft. MD, 11,000 ft. TVD with a 6000 ft. horizontal reach. Some critical considerations for the drill string include –

- High torsional strength requirements for the rotary shoulder connections employed at the drill pipe.
- Optimized hydraulic performance of the drill string is also necessary to maintain good hole cleaning and cuttings removal in the extended horizontal sections.
- The formations are highly abrasive and when combined with long horizontal drilled sections and high side loads between the drill pipe and borehole result in severe wear issues.
- Stick/ slip has been experienced in quite a few shale wells. They can damage the drill pipe and in some cases connection back offs.

The solution provided to these problems which was **High Torque – Streamline Connections** to improve hydraulic performance and drilling efficiency. The 2nd Gen. Double Shoulder Connections was used. It is an advanced, high-performance tool joint design that provides approximately 70% more working torque than standard API connections.

COMPLETION

In Petroleum Production, Well Completion is a method/ process of making a well ready for production. This involves preparing the bottom of the hole to the required specifications, running in the production tubing and its associated down hole tools as well as perforating and stimulating as required. The different types of completion are as follows:

Barefoot Completion

This is the most basic and a good choice for hard rock, multi-laterals and underbalance drilling. It involves leaving the productive reservoir section without any tubular. This mainly removes control of flow of fluids from the formation but it is not suitable for weaker formations which might require sand control, nor for formations requiring selective isolation of oil, gas and water intervals.

Open Hole Completion

It incorporates a range of completions where no casing or liner is cemented in place across the formation. In competent formations, the zone might be left entirely bare, but some sort of sand-control and/or flow-control means are usually incorporated. Open hole completions are often developed to address specific reservoir challenges. There have been many recent developments that have boosted the success of open hole completions, and they also tend to be popular in horizontal wells, where cemented installations are more expensive and technically more difficult.

Liner Completion

In Liner Completion, the casing is set above the primary zone. An un-cemented screen and liner assembly is installed across the pay section. This technique minimizes formation damage and gives the ability to control sand. It also makes cleanout easy. Perforating expense is also low to non-existent. However gas and water build up is difficult to control and selective stimulation is not possible as the well can’t be easily deepened and additional rig time may be needed.

Cased Hole Completions

This involves running casing down through the production zone, and then cementing it in place. Connection between the well bore and the formation is made by perforations. Because perforation intervals can be precisely positioned, this type of completion affords good control of fluid flow, although it relies on the quality of the cement to prevent fluid flow behind the liner. As such it is the most common form of completion.

INTELLIGENT WELL COMPLETIONS

The term “intelligent well” is used to signify that there is some degree of direct monitoring and remote control equipment are installed within the well completion. Thus an intelligent well is a permanent system capable of collecting, transmitting, and analysing wellbore production and reservoir and completion integrity data, and enabling remote action to better control reservoir, well, and production processes.

Remote completion monitoring is defined as the ability of a system to provide data, obtained near the wellbore, without requiring access and entry for conventional intervention to the well. Remote completion control implies that information and instructions can be transmitted into the well to alter the position of one or more completion components. The primary objectives of these abilities are normally to maximize or optimize recovery, minimize operating costs, and improve safety. General benefits of remote completion monitoring and control are as follows:

- Improved recovery (optimize for zonal/manifold pressures, water cuts, and sweep).
- Improved zonal/areal recovery monitoring and accounting.
- Increased production (improved lift and reduced project life).
- Reduced intervention costs.
- Targeted squeeze/stimulation treatments from surface.
- Reduced water handling.

Sensors that are common to smart completions are as follows:

Control Device Performance

For pressure build-up surveys, the requirement is generally for closure “as fast as possible” to obtain early build-up. The speed of closure is determined by the starting position, viable stroke speed (vs. power), and shock considerations. With a down hole zonal flow-control device, there is already the benefit of no wellbore-storage effect, and full closure is expected to be 1 or 2 minutes or less, depending on the starting position. Opening speeds may be limited by sand production considerations. When no survey is being taken, wear and damage to the down hole device may be minimized by simultaneous operation of the surface choke.

Fibre Optics

Fibre optic systems have been developed that enable direct conversion of down hole measured into optical signals. The advantage with fibre-optic systems is their effective immunity to temperature degradation. Subsequent developments in optical sensors have resulted in the down hole deployment of fibre Bragg-Grating sensors configured within transducers to measure pressure, temperature, flow, and seismic data. Packaging and integration of optoelectronic conversion devices into electrohydraulic subsea-control infrastructures has been successfully completed and may be considered mature.

Near Wellbore Sensing

Electromagnetic resistivity arrays have been successfully deployed into wells to monitor near-wellbore effects and determination of fluid-front movement. Combination of these sensors with automated sequencing of down hole control devices to provide enhanced water flood control is now a short-term option.

INTELLIGENT COMPLETIONS IN BRUNEI OFFSHORE

The Champion West field was discovered in 1975 and Phase -1 was initiated in 1994. There the drilling of the wells turned out to be competitive and expensive and hence the development phase was aborted. In 2002, Champion West called for another field development plan where 2 gas and 6 oil wells were planned and from here the first snake and intelligent well concepts were applied. The snake well pattern was characterised as a horizontal sinusoidal pattern cutting through the successive layers of shale and sand packages within the reservoir for at least tice or thrice. The snake wells provides a better drainage area and is equivalent to at least 3-4 short horizontal wells and hence improves the overall ultimate recovery of the reservoirs.

This concept was applied to the Champion West Field because from the past experiences it was known that drawdown was not well balanced and this brings early water break-through into the system and leaves behind substantial reserves from the mid-section of the toe and therefore the smart completion was needed to control the pressure drawdown and to manage when to produce from which layer with the help of ICV (Internal Control Valve) and DTS (Distributed Temperature Sensors). Therefore considering all the points i.e. cater for the needs of the selectivity and an even drawdown and proper well clean-up from heel to toe the introduction of innovative “tilted bucket” concept was introduced. It consists of an open ended Stinger with a variable choke or fixed sliding side door (SSD) which are run into the horizontal sections and thus clean-up and drain the unproduced sections.

BSP adopted/ changed its completion strategies many times depending on the complexity of the reservoir. For the first time the concept started when DTS (Distributed Temperature Sensors) were first installed in two wells. The DTS interpreted that the horizontal sections of 1-2 km wells were only producing from the first 600-800 m in length and thus the remaining sections were not contributing.

For the next time i.e. in Phase-2 the completions were modified accordingly where smart stingers, external casing packers (ECP) and DTS are included. The smart stingers comprised of internal control valves (ICV), lubricator valves (LV) and permanent down hole gauges (PDHG).

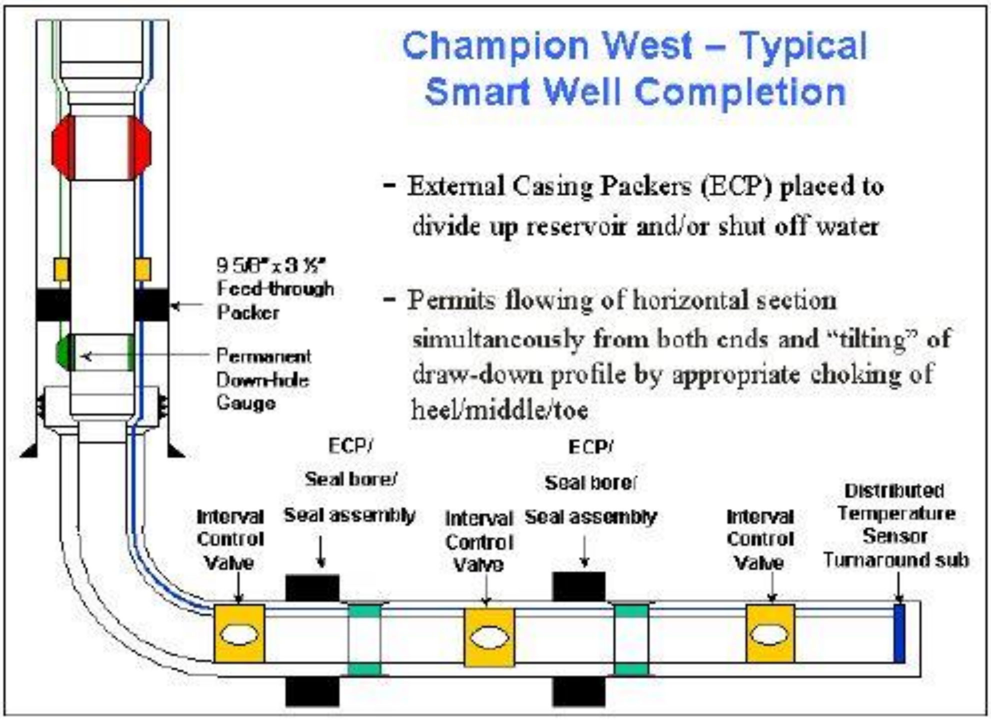

Figure 13: Snake well with Selective Smart Stinger Completion. Courtesy: SPE 88254

So the Phase 2 completion combinations provided flexibility in the completion design if unfriendly water is encountered and also the increase in the ability to respond to the (un) expected changes. Despite of its robustness and flexibility while ensuring to meet the objectives the introduction of the smart stingers with ECPs or swell able elastomers create torque and drag issues as $5\frac{1}{2}^{"}$ or $6\frac{5}{8}^{"}$ liner and $2\frac{7}{8}^{"}$ stinger need to be run to bottom.

In order to alleviate the problems, the completion was designed for the third time where the recommended changes were –

- 7" top of liner need to be raised by 2300 m.
- First 5.1/2" pre-drilled liner will be replaced with 7" pre-drilled to top of the first ECP.
- 3.1/2" tubing will be used instead at the 7" pre-drilled liner sections.

By introducing such changes, the additional stiffness is of the tubing helps to increase the safety margin in getting the completion to bottom and thus reduce the possibility of buckling.

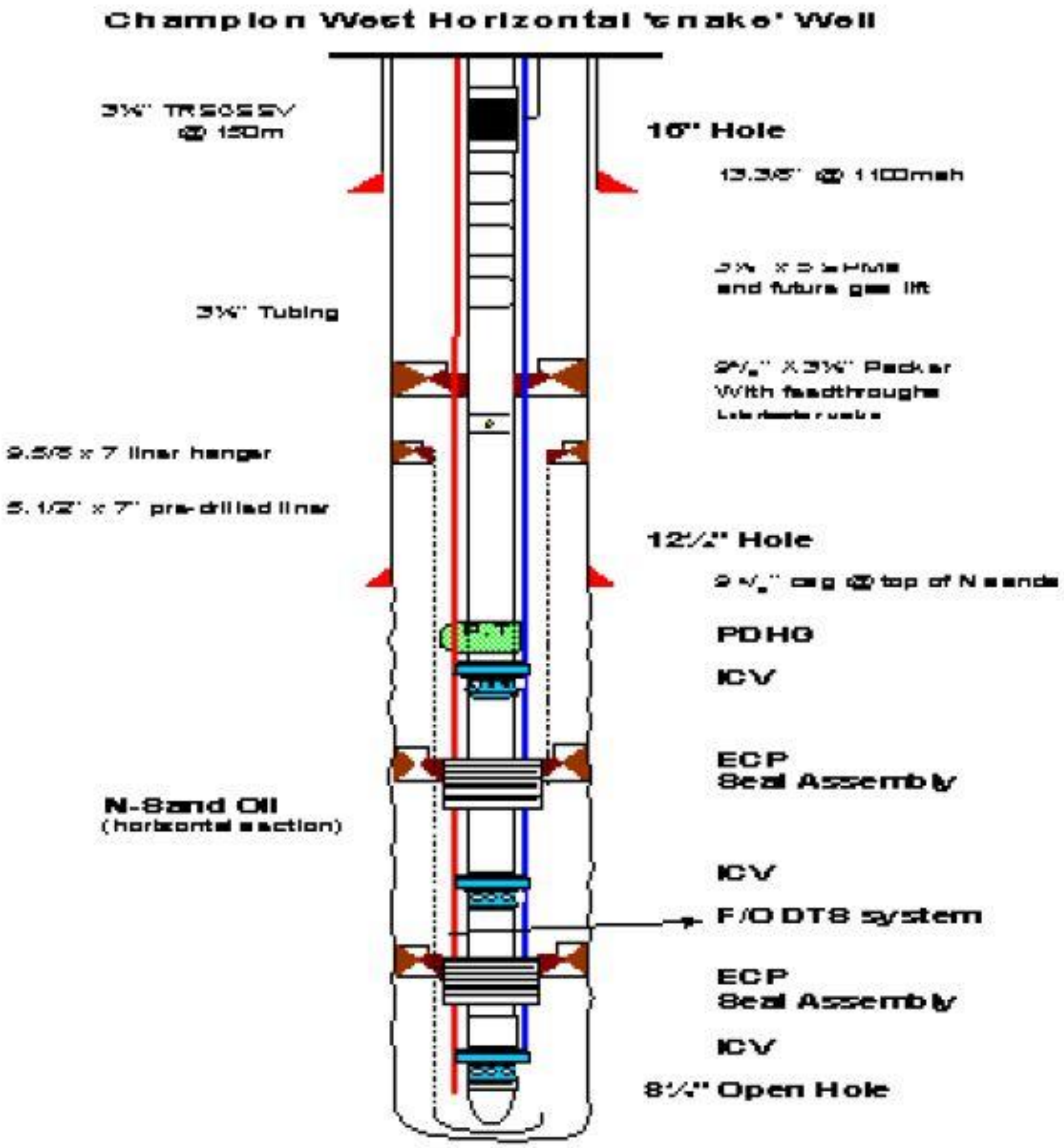

Figure 14: Final Completion Design. Courtesy: SPE 88254

From the above mentioned completion designs it is clear that there are major drilling and well complexities in such type of well which the BSP people are taking into consideration and it is very difficult to pre judge the problems that are going to be encountered even for the BSP engineers. They had to redesign the BHA thrice due the problems which they had encountered including Torque and Drag, Shale Instability problems.

Hence this kind of trajectory is a masterpiece in itself which have been mastered by BSP as they just not have drilled this kind of trajectory but also they are producing form suck kind of complex well and which had also increased the ultimate oil recovery of the reservoir.

SUGGESSTIONS FROM THE ABOVE LITERATURE

As there are problems for the sand control due to shale instability during the completion phase which is causing a lot of problems during production phase and the mitigation of those problems has not been mentioned then but if we have a look on the emerging technologies which can control sand production in combination with smart wells. These technologies include:

Dip Tube or Siphon Tube Solution

The well is completed with a conventional two-stage gravel pack (or screens), isolating the two zones from each other with a section of blank pipe and a packer. The completion is composed, top down, of the production tubing, feed-through production packer, gauge mandrel, ICV, a shrouded ICV, and dip tube with seal assembly which stings into a seal bore in the packer isolating the two zones. Production from the lower zone flows through the dip tube and through the shroud on the lowermost ICV, entering the production tubing through the lowermost ICV. Production from the upper zone flows in the annular area between the upper gravel pack screen, in the annular area between the lowermost ICV shroud and the production casing, and enters the production tubing through the uppermost ICV. The gauge mandrel enables pressure monitoring of both internal and annular areas.

Hydraulic feed through Isolation packer

A second solution for controlling multiple zones with sand control is done where each zone. is completed with (from top down) a hydraulic set, hydraulic feed-through isolation packer, a gravel slurry placement sleeve, a shrouded ICV with the shroud attached to the gravel-pack screen base pipe and the ICV attached to an internal, concentric, through-wellbore, production conduit, which ties into the isolation packer of the next lower interval. The gravel-pack slurry is placed with coiled tubing or a small work string stung into the sand placement sleeve, which acts as a crossover device for flow from the coil to the casing annular area for gravel packing, with returns back up the coiled tubing/tubing annulus. This completion can also be run with screens only, without gravel packing.

Expandable Screens

A third and most promising solution is the use of intelligent-well equipment with expandable screens. This solution maximizes flow areas in both the annulus and the production conduit. Installation of several dip-tube-type completions in the Gulf of Mexico has been successful. Two wells have been completed in the Allegheny field, while two other wells have been completed in the Typhoon field.

CONCLUSION

Snake wells are laterally weaving extended reach horizontal wells that drain a number of vertically stacked, structurally dipping reservoirs. This creates multiple drainage points in each sand and effectively achieves a similar drainage pattern to a multilateral well at a fraction of the cost and technical complexity. Snake wells were introduced in order to cater for the needs of selectivity and an even drawdown and proper well clean-up from heel to toe. The design allows any combination of offtake from 100% from the toe through balanced offtake to 100% at the heel, with consequent control on the drawdown profile illustrates combination of different drawdowns depending on where the stingers and the SSD are located.

The BHA was planned with uttermost care and future predictions, but some unseen problems could never be ruled out of the scenario. Problems like stuck ups while tripping, hole cleaning, hole caving were often experienced. Hence, the entire BHA had to be redesigned in order to mitigate them. The new BHA was based on one-collar LWD concept which allows for minimum stabilisation requirement and reduces its overall length by 10 m from bit to crossover and to the HWDP. After the redesign there was an increase of nearly 35 percent in performance.

But still there were problems with this design which could not be emitted. The main issues were hole instability in shale, hole cleaning and ECD management because of the pressure variation.

The completion process was also completed in three phases. BSP adopted/ changed its completion strategies many times depending on the complexity of the reservoir. For the first time the concept started when DTS (Distributed Temperature Sensors) were first installed in two wells. In phase 2, the completions were modified accordingly where smart stingers, external casing packers (ECP) and DTS are included. The smart stingers comprised of internal control valves (ICV), lubricator valves (LV) and permanent down hole gauges (PDHG). For the 3rd time, less diameter tubing and less diameter liner was used so that they can sustain more drag and torque. But still there were problem of sand control in shale reservoirs.

Today, from the available literature we are suggesting some of the solutions which can mitigate those problems. These include high torque streamline connections, potassium silicate shale stabilizers in mud for the BHA and mud system.

For completion basically for sand control today we have sand control techniques in combinations with intelligent wells which include dip tube solution, hydraulic packers and expandable screens which can be quite effective in controlling sand control.

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