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Underbalanced Drilling Feasibility of Directional Wells using Coiled Tubing

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Abstract

UBCTD (Under Balance Coiled Tubing Drilling) is one of the most prospective unconventional well drilling techniques. It allows reducing the time of connecting and dismantling pipes and increasing the Rate of penetration. It depends on continuous coil of tubes and downhole motor. Also provides better well control using the strippers as the well is already shut-In while drilling operations. The use of E-Coil with downhole orienteer directs this technology to achieve upcoming rig-less drilling operations. This study was done on a multilateral well in, XC reservoir to check the feasibility of applying UBCTD. The main parameters in the technical feasibility are designing the Aerated Mud, WOB deliverability and the lock-up problem. The optimum gas–liquid flow Rate window (GLFRW) design is based on Guo-Ghalambor Method. The mechanical design including tubing selection to overcome coil buckling in hole, due to mechanical forces available at the drilling bit. UBCTD is found to be the optimum technique to drill mature reservoirs and heterogeneous reservoirs with many pressure barriers. The use of PDC Bit with its different shapes based on the design will be the best solution as it doesn't require WOB as much as tri-cone bit. Also shallow wells will encounter less buckling and lock-Up problems. With regard to the cost and Achieve the rigless operation. A hybrid design of CT Units will provide light mast to make the deployment of downhole tools. The cost of the injected gas like nitrogen and air is a major cost parameter and shall be designed with optimum GLFRW. The aforementioned cost parameters shall be studied in detail against the benefits of UBCTD with regards contingency factor to achieve optimal cost effective drilling operation.

Keywords: *Underbalance drilling feasibility; Coiled tubing design; Gas-liquid flow rate; Coiled tubing buckling; Coiled tubing lock-up.*

1. Introduction

The need of reduction in field development costs and safe drilling operation has been a very good incentive for development of new technologies to solve the economic equation in marginal fields. Using coiled tubing in drilling application was very prospective in shallow and medium wells especially in multilateral drilling operations with different scales from through tubing drilling (TTD) to 5.5" side tracks as a proven technology since 1990s which known as Coiled Tubing Drilling (CTD) with greatly reduced footprint [1].

CTD is utilized first in early 1990s for drilling re-entry wells and has accelerated as drilling application. Technical and logistic challenges in mature area have considerable risks that require risk assessment to make the decision. [2].

Casing running and BHA deployment usually is not a common feature of CT unit so using CT unit while the drilling rig in operation mode or mobile cranes allows the service companies to build hybrid units which combine the features of the drilling mast with capabilities of hoisting using either wireline or hydraulic lifting [2].

2. Study methodology

The feasibility phase is carried out to identify wells designs feasibility, assess the associated risks due to technical Challenges and the proposed benefits from using UBCTD rather than conventional rotary drilling. Optimized drilling parameters such as rate of penetration, hole cleaning efficiency and tripping time must be defined. These parameters are dependent on hydraulic performance and mechanical forces available at the drilling bit In addition to primarily condition of the wellbore (tubing and open hole size, well friction).

The flowchart below (Figure 2) illustrates the dependency of selections and alternatives options. When objectives cannot be met as the final goal, changing the design parameters may rout the drilling project to be technically feasible.

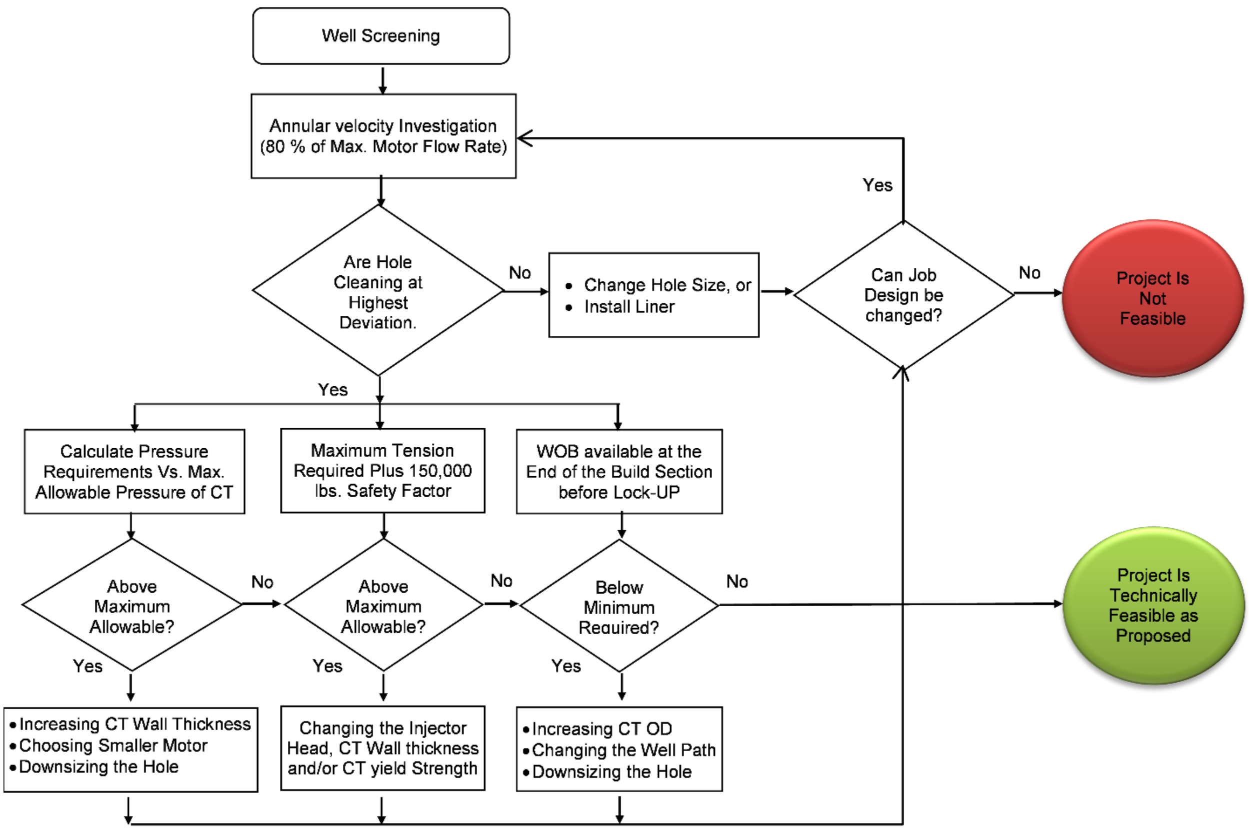

Figure 2. UBCTD technical feasibility flowchart.

2.1. Well screening

For the technical evaluation, candidate wells data which is considered as a basement to initiate feasibility phase should be analyzed when feasibility phase is carried out. When well path is defined, it is important to check the annular velocity drilling parameter such as WOB limitation due to helical buckling, maximum available tension on CT, CT fatigue life and hole cleaning efficiency which is related to maximum possible pump pressure. Although, CTD can be technically feasible but operators may conclude the drilling project does not meet the economical expectation. Therefore, feasibility studies to address the project risk and challenges with expected outcome are vital for successful project management. The majority of operational time is spent in reservoir section. Extra well control awareness is needed [3].

The feasibility of UBCTD project planned on X Field which the study is related to, kicked off with candidate well in which known accumulations of hydrocarbons is oil in XC reservoir. The study is based on drilling three laterals across XC reservoir and was to be re-entered the preset well MXC with MXC-5, MXC-7 and MXC-9 which were being in a reservoir with depth 4028 m (13215ft). The three laterals are placed in the maximum stress direction. The well was completed with 4-1/2" cemented liner and liner top packer.

Reservoir conditions in the XC Formation are generally characterized by high pressure and high temperature with temperatures up to 300 degrees Celsius and pressures as high as 10,000 psi. Overall, the XC Reservoir is considered a challenging but valuable resource for natural gas and oil production due to its location and the quality of the hydrocarbons present in the formation.

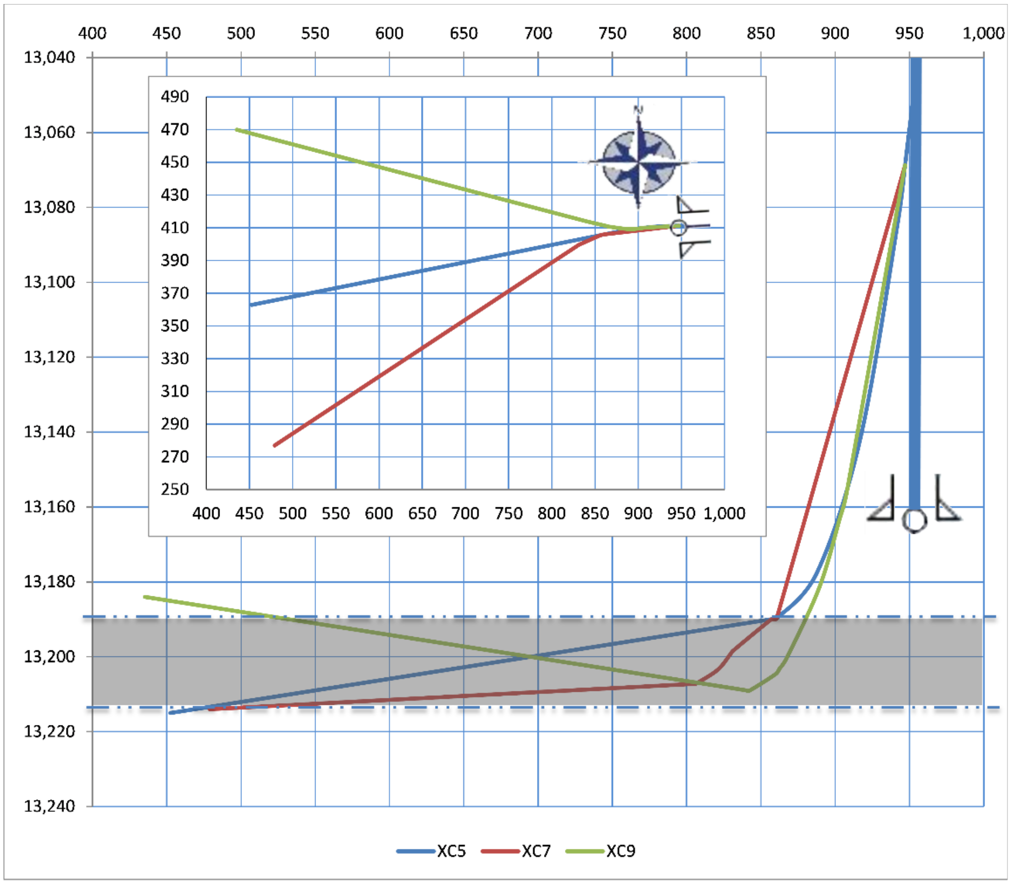

Figure 3. Plot and survey for the candidate laterals.

2.2. Hydraulic design

A UBCTD design requires the optimization of different factors to meet its objectives. The design must take in consideration many variables such as CT ID and length, fluids density and rheology, velocity, fluid temperature and well head pressure. An iterative calculation is done using multiphase flow and particle transport in deviated well.

The basic requirements for drilling fluid's rheology used in conventional drilling are different when operating with UBCTD. Therefore; drilling fluid must be designed to minimize pressure losses induced due to friction as well as minimizing the equivalent circulating density (ECD). Experiences have showed that using low viscosity fluid can maintain better hole cleaning because it will stay in turbulent flow even with low rates and preventing solids accumulation in the wellbore leading to better hole cleaning efficiency [4].

2.2.1. Liquid – gas flow rate window (LGFRW)

The combination of liquid flow rate and gas injection rate should be carefully designed so the flowing bottom-hole pressure is less than the formation pore pressure under drilling conditions and the circulation-break bottom-hole pressure (static) is greater than the formation collapse pressure. Other considerations in designing liquid and gas flow rates include cuttings-carrying capacity of the fluid mixture and wellbore washout. The former defines the lower boundary of useable flow rate combinations, and the latter defines the upper limit [5].

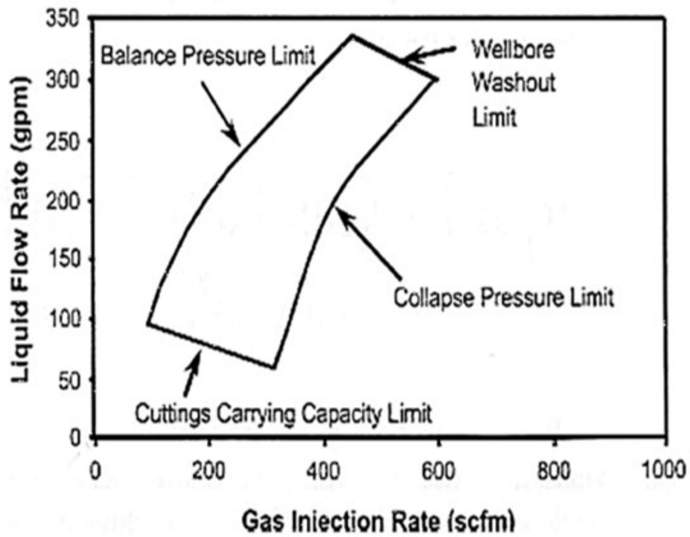

Figure 4. Typical liquid-gas flow rate window.

Based on the formation pore pressure, wellbore collapse pressure, fluid mixture carrying capacity of the cuttings, and borehole washout criteria, the window can be built. Figure 4 presents an illustration of a typical LGFRW [4].

Under typical drilling and circulation breaking conditions, a significant element determining bottom hole pressures is the combination of liquid and gas flow rates. As a result, it regulates the proportion of formation damage to wellbore damage during UBCTD operations.

2.2.1.1. Collapse limit

To establish the right boundary, we calculate the bottom-hole pressures under different mud flow and gas injection rates during aerated liquid drilling, while breaking the circulation [6].

The results are depicted in Figure 5. The horizontal line in the figure represents the circulation-break bottom-hole pressure of 2,800 psia. With a constant mud flow rate, as we increase the gas injection rate, the hydrostatic bottom-hole pressure decreases due to lower mud weight resulting from gas injection.

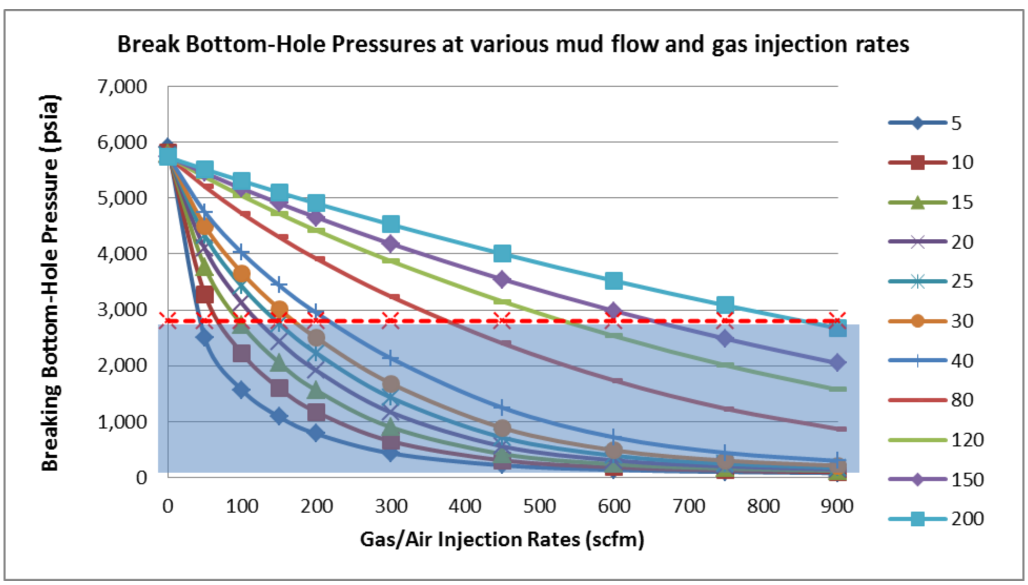

Figure 5. Determination bottom-hole pressure at various mud flow and gas injection rates.

For higher mud flow rates, we can still increase the gas injection rate further, and the static bottom-hole pressure is still greater than the collapse pressure. The intersects of these plots with the line of 2,800 psi are at 45, 65, 95, 119, 145, 170, 215, 370, 530, and 650 SCFM for mud flow rates of 5, 10, 15, 20, 25, 30, 80, 120, and 150 GPM respectively.

These figures suggest that exceeding the indicated gas/air injection rates may lead to inadequate borehole stability during breaking operations as the static bottom-hole pressures would be lower than the formation's collapse pressure.

2.2.1.2. Balance limit

To maintain underbalanced conditions during the construction of the left boundary, we make sure that the maximum pressure of the resulting flow is lower than the formation or reservoir pressure. To calculate the flowing bottom-hole pressure, we add the frictional pressure losses to the static bottom-hole pressures. We can determine the flowing bottom-hole pressures at different rates of mud flow and gas injection while taking into account the frictional pressure losses [6]. The results are summarized and plotted in Figure 6. A horizontal line is drawn in the figure at a flowing bottom-hole pressure of 4,000 PSIA. For mud flow rates of 100, 200, 300, and 400 GPM, if we decrease the gas injection rate below 124, 220, 317, and 413 SCFM, respectively, the underbalanced situation would no longer exist.

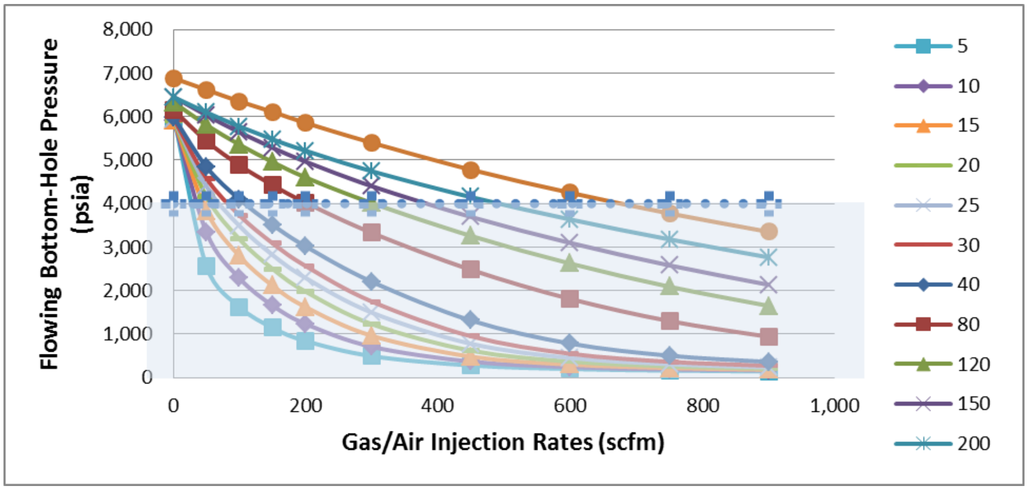

Figure 6. Determination of flow rate combination that will yield balanced bottom-hole pressure.

2.2.1.3. Cutting carrying capacity

The process of wellbore cleaning is directly related to the velocity of fluid in the annulus, which can be calculated based on the diameter of the hole and the size of the tubing. The largest available downhole motor can be selected based on the hole size, and the diameter of the motor determines 80% of the maximum fluid rate that can pass through it, resulting in the annular velocity that can be achieved. The horizontal or high deviated sections and areas with larger well ID are considered to be the most critical sections for hole cleaning efficiency due to slower annular velocities.

To determine the lower boundary for evaluation, we consider a mixture of flow rates to obtain the minimum cuttings carrying capacity based on a minimum kinetic energy of 3 lbf-ft/ft^3. The required cuttings transport velocity depends on the rate at which cuttings are generated by the drill bit and the quantity of moving cuttings allowed in the borehole during drilling.

CT coil CAD is used to predict the minimum annular velocity required for a given wellbore size with different deviation angles, ranging from vertical to horizontal sections. If the maximum annular velocity is not sufficient for hole cleaning, a larger CT must be selected to increase the flow rate through the coil and reduce the annular cross-sectional area. If a larger CT is not available, operators must consider reducing the hole size to improve annular velocity and maintain hole cleaning efficiency.

The cuttings carrying capacity of mud at different flow rates is calculated, considering both liquid-only phase capacity and liquid capacity mixed with gas/air injection rates. By considering zero gas flow rate and for the second point, we use a range of gas/air injection rates. This calculation helps determine the minimum mud and gas flow rates required for effective cuttings carrying capacity as represented in Figure 7.

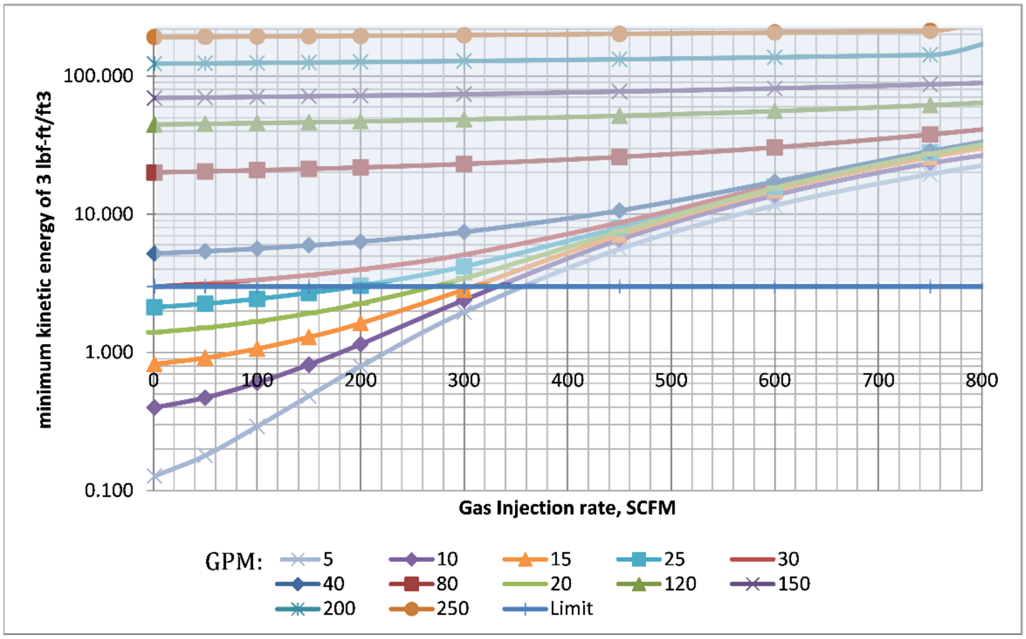

Figure 7. Determination of the cuttings carrying capacity of the mud at different flow rates.

2.2.1.4. Washout limit

Without knowing geological details and clear washout criteria throughout the open-hole section in the area and wellbore washout experience, it is difficult to close the upper boundary of the flow rate envelope. The resultant LGRW is presented in Figure 8 with uncertainty of the upper boundary. Although any combination of gas and liquid rates within the envelope is safe to use, those combinations near the lower boundary are considered optimal, concerning energy consumption in liquid pumping and gas injection.

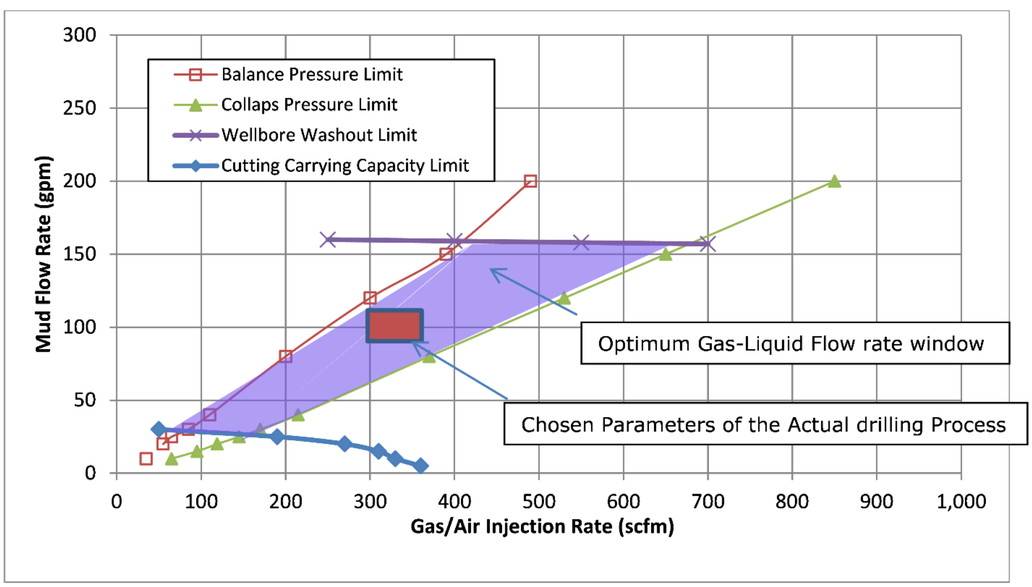

Figure 8. General LGFRW for the implemented well.

The optimum gas-liquid flow rate combination is indicated in Figure 6 shadowed in blue colour with wide Range of GPM and SCFM. The best combination of mud cost and nitrogen cost for offset well data was mud flow rate between 80 to 125 GPM and Nitrogen gas injection rate between 300 to 365 SCFM.

LGFRW can help us to a great deal for designing a better UBD operation and defining limitations by considering borehole collapse pressure, formation and reservoir pressure, cuttings carrying capacity of the designed mud, and washout consideration in open-hole section of the well.

2.3. CT mechanical design

The required CT tubing string shall be selected based on the proposed loads and including but not limited to axial tension, burst, collapse and buckling [2].

2.3.1. Tubing tension

To determine the appropriate tubing for a given operation, the tension forces acting on the tubing must consider a variety of factors, including the weight of the tubing, the potential for buckling, the temperature of the wellbore, the buoyancy of the tubing, and friction within the wellbore. Through simulation, it is possible to predict the maximum surface tension and drag that can be expected. CT maximum tensile limit is compared to the expected tension plus an additional 15000 lb of over pull [2].

2.3.2. Weight on bit (WOB)

It is important to determine the compression loads that can be applied on the CT to provide the required WOB taking in considerations the buildup section and DLS along the wellbore. Similarly, the tensile load, the maximum needed compression load must be compared with the CT designed compressional load to confirm the suitability of the CT for the operation [2].

2.3.3. CT buckling and lock-up

By itself, buckling of CT is not a serious problem. It is an elastic deformation that does not damage the CT. Under favourable conditions, buckled CT can continue to slide and transmit axial force. Buckling significantly increases the normal force (drag) between the CT and wellbore. This always reduces available WOB, and may lead to lock-up, if the compressive force above the buckled section increases high enough. Figure 7 displays illustration of the Buckling state of tubular strings in a horizontal well [7].

The graph presented in Figure 9 provides a schematic view of the buckling state of tubular strings in a horizontal well. In the horizontal section, the tubular string is in axial compression state, and the axial compressive force on the tubular string increases from the drill bit to the starting point of the horizontal section.

If the axial force is smaller than the critical buckling load, the tubular string lies on the bottom of the wellbore. However, if the axial force exceeds the critical sinusoidal or helical buckling load, the tubular string enters into buckling state, and its deflection curve is depicted by a sinusoidal curve or a helix. Buckling tends to occur on the starting part of the horizontal section shown in Figure 9.

In the build-up section, the tubular string is usually in non-buckling state due to the increase of buckling load caused by the effect of curved wellbore configuration. The tubular string tends to touch the bottom of the build-up wellbore.

In the vertical wellbore, as the axial compressive force increases with depth, if it is smaller than the critical helical buckling load, the tubular string keeps in straight line state. However, if it exceeds this critical helical buckling load, then it becomes into helix state. Therefore, helical buckling tends to occur on the bottom part of the vertical wellbore.

This graph helps to understand how buckling occurs in different parts of a well trajectory and how it affects tubular strings' behaviour during drilling operations. It also highlights that buckling is more likely to occur in horizontal sections due to lower axial forces compared to vertical sections where higher axial forces can lead to helical buckling.

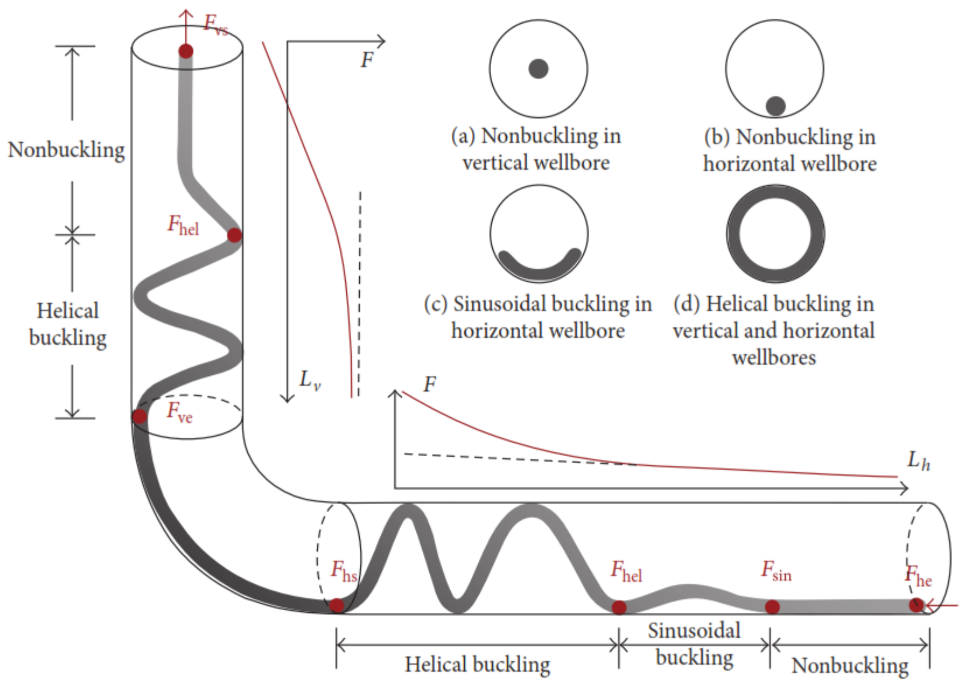

Figure 9. Buckling state of tubular strings in a horizontal well.

CT Coil CAD is used that predicts the maximum available WOB that can be applied for the given CT size. This parameter is crucial for drilling in horizontal and highly deviated wells. The initial Parameters of the check was using 1.75” Tubing diameter and 0.109” tubing wall thickness and found that it will lock-UP at 10,000 ft MD without ability of delivering WOB. So that we tried to use 2.00” diameter and finally the optimum design was on 2 3/8” that can deliver WOB till 14000 ft. MD.

The results of this computer modelling using CT COIL CAD are shown in the following Figures 10 and 11. Figure 10 displays the maximum Weight on Bit "Compressive Load at the tool" before CT reaches the lock-up condition when RIH and before CT Reaches 80% of yield strength for a proposed Ct 2 3/8in Dia. string with thickness of 0.109 in. made of HT 95 Material. Figure 11 displays the Max. Available WOB, lbf, for the measured depth in ft for 3 coiled tubing sizes Using SLB Coil CAD.

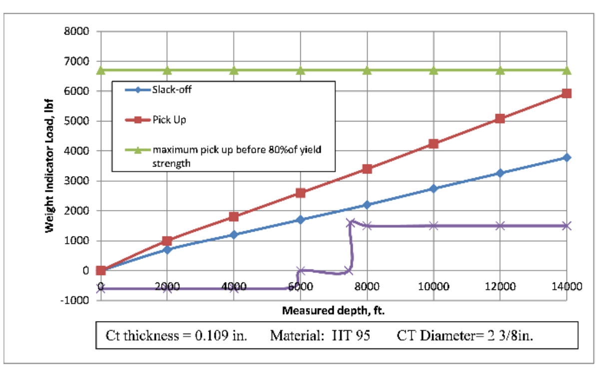

Figure 10. Weight indicator, lbt, for the measured depth, ft, using SLB coil CAD.

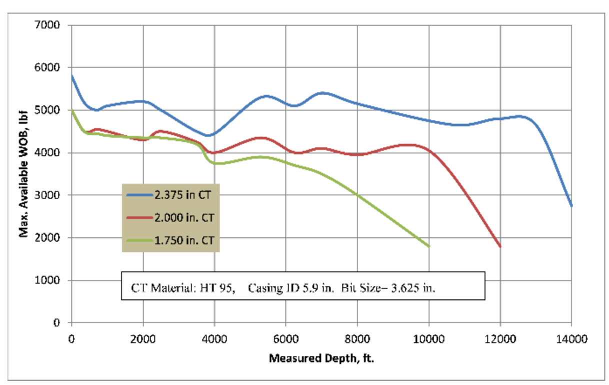

Figure 11. Max. available WOB, lbt, for the measured depth, ft, using SLB coil CAD.

The KOP.s of all Laterals was greater than 13000’ and the max. Available WOB is between 4500 and 2500 lbf which are appropriate for PDC Bit. From Figure .9 the best tubing Size was

2-3/8" Dia. which was Capable of delivering WOB up to 4000 lbf. for 13200' MD. with Casing ID 5.9 in. However, the drilling speed of 20 ft/hr. which is not greater than using drill pipes, the advantage of precise directional control, 15°/100 ft DLS, MWD and LWD data in UBD using E-Coil are much essential rather than using drill-pipes in drilling thin pay zone.

The KOP.s of all Laterals was greater than 13000' and the max. Available WOB is between 4500 and 2500 lbf which are appropriate for PDC Bit not Tri-Cone.

3. Time and cost

Taking in considerations the technical limits during execution phase, UBCTD should be optimized to ensure effective cost strategy like other Projects. The most competitive solutions that offers the most effective cost saving should be chosen. The cost is inter-connected with project's time estimation which can be predicted by the aid of using actual time spent to perform the specific task based on other wells that already drilled. Total cost can be reduced when experience is built up [3].

The daily rental cost and services that are run during well intervention, and then for drilling, and completion multiplied by the number of days estimated can give sufficient cost estimated needed for the execution phase.

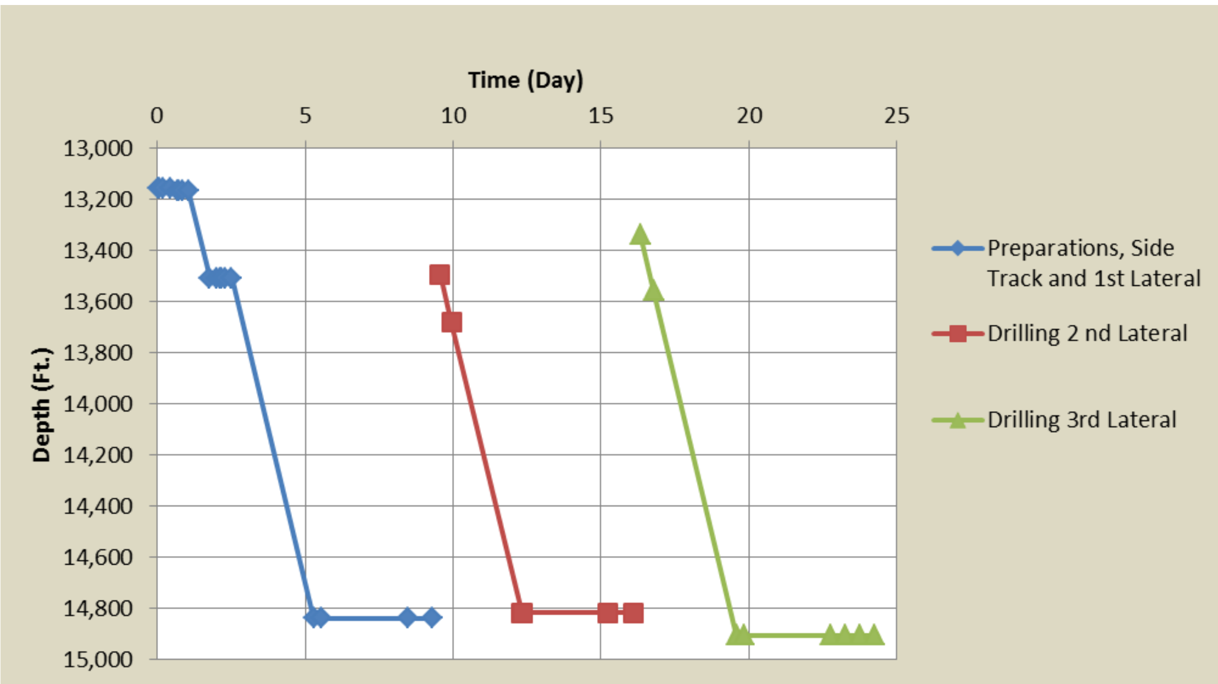

Figure 12. Time vs measured depth.

Unlike the drill pipe used for conventional drilling, the CT has limited life depending on many factor such as pressure, number of cycle over the goose neck. In general, the CT itself can contribute up to 10% of the total UBCTD well cost. The surface equipment and BHA rental costs together are considered the major contributors to the total cost needed for the UBCTD. This can be as much as 30% of the total cost need to drill the well [10]. Figure 12 illustrates the actual recorded time breakdown for drilling the three lateral Sections.

4. Conventional drilling of directional wells (Egypt)

ARMW-8H: is an onshore development well with Horizontal Maximum inclination of 85° with Target of Nukhul formation (Top @ 3516 m MD / -2542 m TVD ss. Total Depth of the well was 3842 m MD/ -2570 m TVD ss. The aim of this well was to maximize the drainage interval in the layers Nukhul A, Nukhul B and adding also layer Nukhul C never put in production with a horizontal well. Figure 13 is the actual survey and plot of ARM W8H.

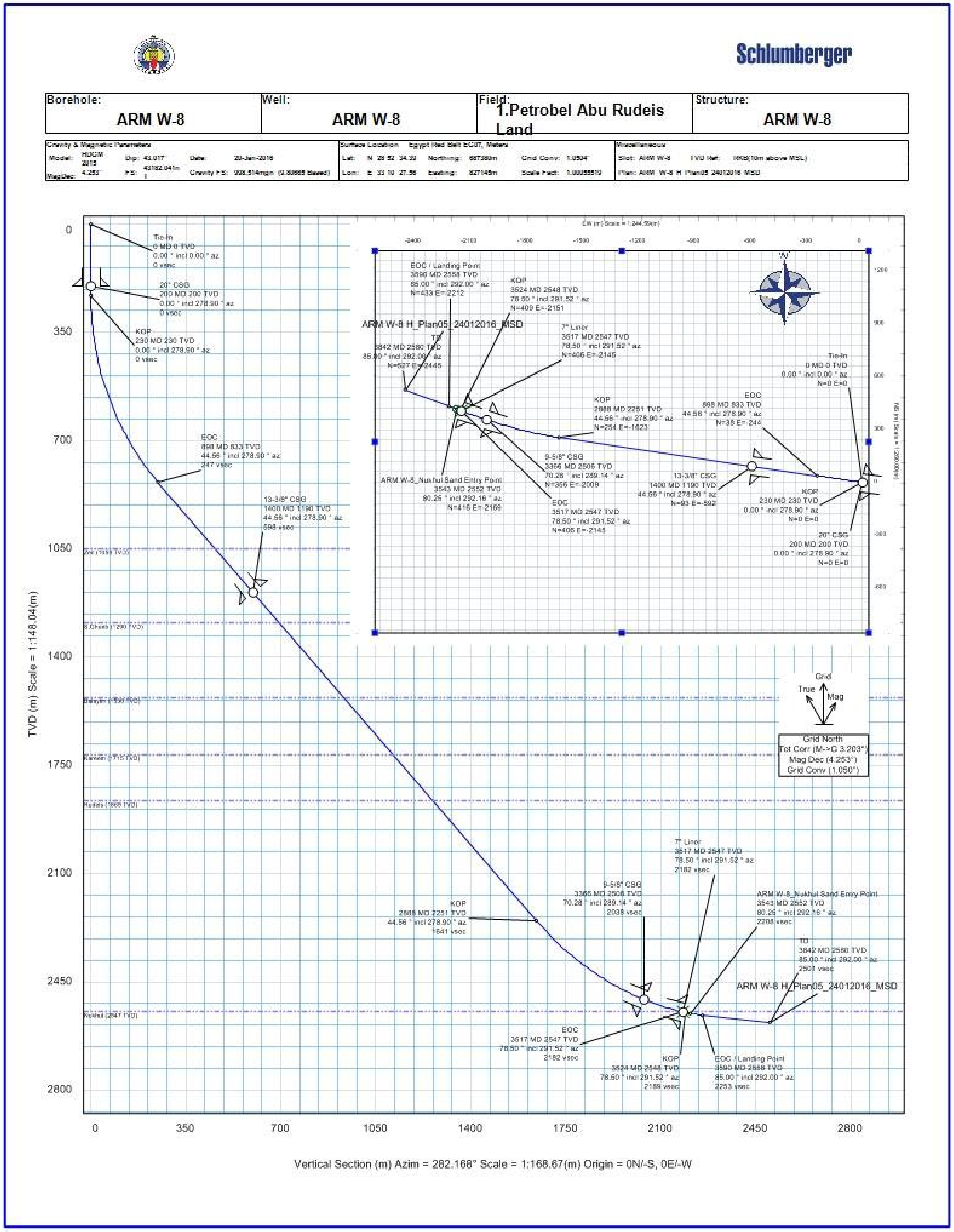

Figure 13. Actual survey and plot of ARM V8H.

During drilling operations, tight spots were encountered at depths of 1447m, 1449m, and 1551m with a weight on bit (WOB) of 20 kilogram-force (kLBs). Additionally, tight spots were

encountered between depths of 1580m and 1386m. Against the S. Ghareb Salt formation, tight spots were encountered at depths of 2558m, 2549m, and 2519m with a WOB of 20 kLBs over pull. The drill string became stuck at depths of 2516m and 2869m, but was subsequently freed. Tight spots were also encountered at depths of 2160m and 2630m with a WOB of 20 kLBs over pull, and a colliding tool became stuck inside the string at a depth of 3835m. The cable was cut during these operations. The drill string became stuck again at a depth of 4635m while drilling the Turonian formation, but was freed. The string also became stuck at depths of 4584m and 4663m during washing up and drilling operations, respectively, but was subsequently freed as well. While drilling at a depth of 4567m, there was a completion loss.
The following Figures 14 and 15 are typically the time vs. depth of ARM W8H and cost vs. depth of ARM W8H respectively.

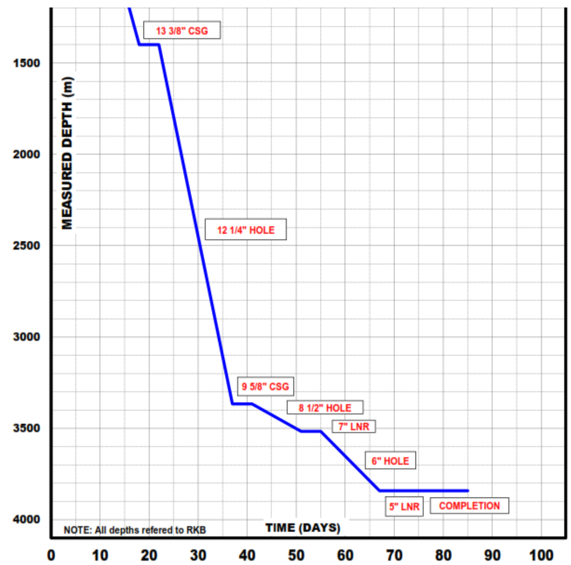

Figure 14. Time vs depth of ARM W8H.

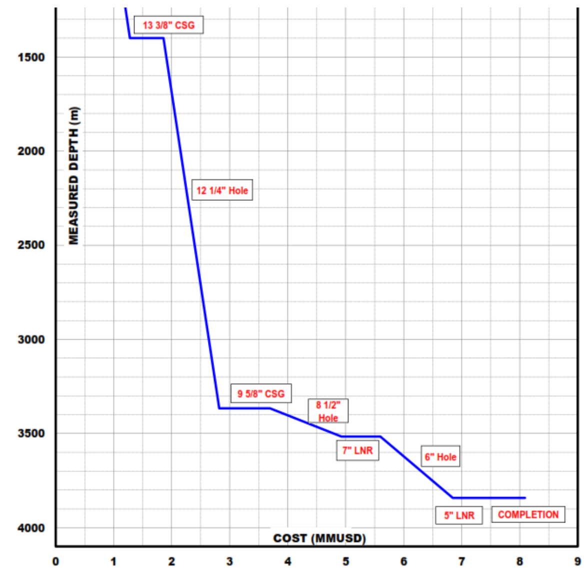

Figure 15. Cost vs depth of ARM W8H.

5. Discussion

Drilling re-entry wells using UBCTD application in parallel to conventional drilling from the rig derrick represents a great opportunity to double the number of wells drilled, and targets more formations.

The two wells MXC and ARMW8H were found similar in the objective and target formations but ARMW8H was drilled conventionally and MXC was drilled using UBCTD but they completely different in tolerating and control of the drilling problems.

As shown in the following comparison table 1. Using rigid pipes makes the well trajectory long due to long radius of the buildup section however the drilling using coiled tubing was done in short radius mode which give the benefits to increase the reservoir footage, reduce the well trajectory length and accurate orienting the tool face in the thin formations.

Weight on bit (WOB): In conventional drilling, the WOB is typically higher than in the operations described, as the focus is on penetration rate rather than minimizing formation damage. In under balance coiled tubing drilling, the WOB is relatively small due to the mechanical limitation of the Coiled tubing string so it always needs A PDC Bit with underbalance MW to increase the efficiency of Drilling operations.

Bit Type: Only PDC Bit for UBCTD application as it needs low WOB with underbalance MW to increase the efficiency of Drilling operations, However Tri-Cone or PDC are suitable based on the drilling Program for conventional rotary drilling.

Drilling time of Laterals was 22 days for three laterals with total footage of 3819 including Open Hole Completion, however for Conventional drilling was 30 days only for horizontal Section with total footage of 781 including 5” Liner installation

Total Cost for Horizontal Section (USD): a cost of 2.8 MMUSD for three laterals with total footage of 3819 including Open Hole Completion against 2.7 MMUSD in conventional drilling only for horizontal Section with total footage of 781 including 5” Liner installation.

Table 1. Comparison between a UBCTD and conventional drilling for similar wells.

	UBCTD , MXC well	UBD, ARMW8H
Target reservoir	XC is high quality oil production 750 m^3/d	Nukhul formation, initial rate is about 300 m^3/d
Pressure (psi.)	10,000	1500
Temperatures ° C	300	320
TD (m)	4028	4567m
inclination	89°	85°
Plan	Re-entry the pre-set well MXC with MXC-5, MXC-7 and MXC-9. The well was completed with 4-1/2” cemented liner and liner top packer	The aim of this well was to Maximize the drainage interval in Nukhul C with a horizontal well.
Drilling fluid	Aerated Fluid (UBCTD)	OBM (UBD)
KOP MD, (m)	13681, 13508,13558	230
BUS length (m)	110, 60, 79	668
Reservoir footage	1333, 1137, 1349	781
WOB	Relatively small due to the mechanical limitation of the Coiled tubing string	In conventional drilling, the WOB is typically higher due to Pipe Rigidity.
Bit Type	Only PDC Bit as it needs low WOB with underbalance MW to increase the efficiency of Drilling operations.	Tri-Cone or PDC are suitable based on the drilling Program.
Drilling time of Laterals	22 days for three laterals with total footage of 3819 including Open Hole Completion	30 days only for horizontal Section with total footage of 781 including 5” Liner installation
Total cost for horizontal section (USD)	2.8 MMUSD for three laterals with total footage of 3819 including Open Hole Completion	2.7 MMUSD only for horizontal Section with total footage of 781 including 5” Liner installation

Tight spots are more common in conventional drilling due to the Shale swelling, Pipe Rigidity and higher WOB, which can reduce drilling efficiency. Under balance coiled tubing drilling aims to minimize tight spots by maintaining a stable wellbore and avoiding overburden pressure. Collaring tools are not typically used in conventional drilling, as they are designed to prevent collapsing of the wellbore during directional drilling. However, they may be used in under balance coiled tubing drilling to stabilize the wellbore and prevent collapse.

String stuck is more common in conventional drilling due to the higher MW and potential for formation damage. Under balance coiled tubing drilling aims to minimize string stuck by maintaining a stable wellbore and avoiding overburden pressure.

Completion loss is less common in under balance coiled tubing drilling due to the lower MW and focus on minimizing formation damage. However, it can still occur due to issues with the wellbore integrity or other factors. Overall, under balance coiled tubing drilling aims to minimize formation damage and maximize wellbore integrity, while conventional drilling focuses more on penetration rate and may result in more formation damage and wellbore instability.

6. Study results

The study's findings have several implications for industry and practice:

Demonstration of UBCTD feasibility: The study provides evidence that UBCTD is a viable drilling technique for horizontal wells, which can offer significant benefits over traditional drilling methods, particularly in unconventional plays.

Identification of key challenges: The study highlights the importance of fluid management and wellbore stability in UBCTD, which can be challenging due to the unique characteristics of horizontal wells. These findings can help operators to better understand the risks and limitations of UBCTD and to develop strategies to mitigate these challenges.

Development of best practices: Based on the study's findings, recommendations are provided for best practices in UBCTD, including the use of specialized drilling fluids, optimization of drillstring design, and careful consideration of wellbore stability issues. These recommendations can help operators to safely and effectively implement UBCTD in their operations.

Advancement of technology: The study identifies areas where further research and development is needed to fully realize the potential benefits of UBCTD, such as improved fluid management technologies and more advanced wellbore stability models. These insights can help technology providers to develop new products and services that address these challenges and improve the efficiency and safety of UBCTD operations.

7. Conclusions

The feasibility study on underbalance drilling in horizontal and deviated wells using coiled tubing (UBCTD) is a significant contribution to the oil and gas industry as it explores the potential benefits and challenges of this emerging drilling technique. The study provides insights into the technical and operational aspects of UBCTD , including fluid management, wellbore stability, and equipment requirements.

Overall, this feasibility study provides valuable insights into the potential benefits and challenges of UBCTD for horizontal wells, which can help operators to make informed decisions about whether this technique is appropriate for their specific applications. By addressing the key challenges identified in the study and developing best practices for UBCTD implementation, operators can realize the benefits of this emerging drilling technique while minimizing risks and costs.

The hole cleaning efficiency in UBCTD depends on drilling fluid density, maximum achievable flow rates of Mud and injected gas and pressure at surface which will dictate the annular velocity needed to lift the drilling cuttings. Any failure in maintaining underbalanced situation will result in severe formation damage and from this point of view, designing and controlling operations during UBCTD is crucial. The combination of liquid and gas flow rates is a key factor affecting bottom-hole pressures during normal drilling and circulation breaking conditions. It therefore controls the balance between formation damage and wellbore damage in UBD operations.

Field case studies indicate that the LGFRW approach is consistent with the computer program approach currently used in petroleum industry. The LGFRW approach is more transparent and easier-to-use than the computer program approach by both design engineers and field supervision engineers.

The maximum available WOB the total lateral length is dependent on the total depth, wellbore geometry, CT size and material grade.

As hole stability can be an issue with heavy drilling fluid, the well trajectories are planned to avoid the over pressurized shale. The openhole clad (OHC) can be used to isolate over pressured zones that might be encountered along the well path

So many parameters and situations that should be taken into account while changing from overbalanced to underbalanced operation. Time and cost, beside other instrumental conveniences and trained personnel should take part in our UBCTD decisions.

UBCTD is becoming increasingly popular in the oil and gas industry, particularly in unconventional plays where traditional drilling methods may be less effective. However, there are still some challenges associated with UBCTD, such as the need for specialized equipment and expertise, as well as potential issues related to wellbore stability and fluid management. As a result, further research and development is needed to fully realize the potential benefits of UBCTD and to ensure its safe and effective implementation in industry practice.

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