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Research on the application of wellbore strengthening methodology and managed pressure drilling for HTHP wells in highly depleted reservoirs at the Nam Con Son basin

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ABSTRACT

The gas production in high-temperature, high-pressure (HTHP) projects in the Nam Con Son basin is entering a declining production phase, the production duration almost reaching the final phase of the designed field life. Therefore, the need to build a development plan for maintaining and supplementing gas production is the most important in the current phase. Evaluation of gas field conditions, drilling infill wells to expand existing prospects is considered a feasible solution both technically and economically. However, the physical characteristics of the production reservoirs have changed after a long production time, including a decrease in pore pressure at the production reservoirs, posing a significant technical challenge during the drilling operations. The infill wells are required to penetrate through the shale formations interbedded with sand formations. In there, the cap rock shale layer remains at or close to virgin pressure and the sand reservoir with pore and fracture pressures has largely decreased due to production activities. There is no mud-weight window that exists any more at the transition between cap rock and reservoirs which leads to drilling problems such as loss circulation, gas kicks and especially, the well could not reach the total desired depth or production targets which impact to overall development project. This article evaluates the applicability of a combination of technologies, including utilizing special lost circulation materials to seal the fractures due to changes in reservoir properties and the application of managed pressure drilling methodologies while drilling through infill wells in HTHP conditions. The goal is to minimize the risks of well problems and provide the management of uncertainties during the drilling which improves project efficiency.

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1. Introduction

Referring to the database in Vietnam in recent years, the production rate of gas and condensate by operators operating HTHP projects at the Nam Con Son basin contributes more than 18% of the total production rate of barrel oil equivalent (BOE) in Vietnam.

The major gas and condensate produced in this basin are mostly distributed across multiple sandstone reservoirs in the Miocene strata. Generally, the reservoir quality is good, characterized by a high net-to-gross ratio, good porosity, and low water saturation. The sandstone formations are typically composed of clean, very fine to fine quartz grains and are commonly loose, although occasionally cemented by calcite or argillaceous matrix, resulting in relatively poor visible porosity.

HTHP area is located in the centre of the basin, which is one of highest highest-profile HTHPs in Vietnam. The production reservoirs lie from upper to middle Miocene formations, the depth in the range of 3,200÷3,800 m TVD SS (true vertical depth below mean sea level). Its original pore pressure was 16.0÷17.0 ppg, the maximum fracture gradient in the production zone is 18.5 pg, and the bottom hole temperature is up to 203^{0}C. (Avirup & Amita, 2015; Scott, 2023). The hydrocarbon production consists of gas and condensate with a maximum of 5÷7% CO_2, no H_2S.

The first production well at the Nam Con Son basin commenced providing the first gas more than a decade ago. Therefore, with the ongoing gas and condensate production activities, the reservoirs shall be depleted (Maurice, 2001), as indicated below:

- A reduction of pore pressure and fracture pressure in the depleted zone.

- The change of rock mechanic properties affects the wellbore stability.

The expected reservoir pore pressure and wellbore stability prediction were taken based on the results of geomechanical modelling; and the analysis of PLT data was recorded from offset production wells. The depleted pressure and fracture gradient in a typical production well at the Nam Con Son basin are shown in Figure 1.

Referring to the picture above for wells drilled before depletion occurs, a mud-weight window exists between the pore pressure and the fracture pressure. The minimum mud window is in the range of 0.8÷1.2 ppg which could apply the conventional drilling methodology for exploration/appraisal and production wells. When depletion occurs, the fracture pressure in the reservoir decreases along with the pore pressure. At the interface between the cap rock, which remains at virgin pressure, and the depleted reservoir, there are no mud-weight windows anymore (Fambon & Joffroy, 2008).

1.1. Pore pressure & Fracture gradient profile

The results of pore pressure prediction modeling and logging data from the offset HTHP wells drilled in the Nam Con Son basin indicated a normal trend of pore pressure and fracture gradient from the seabed to the expected top of the Middle Miocene strata at a depth of approximately 2,100 m TVD SS. Subsequently, an abnormal pore pressure and fracture gradient occurred in the MMU (Middle Miocene Unconformity) at a depth of approximately 3,100 m TVD SS. The pressure gradient in this interval increased up to 0.6÷0.8 ppg/100 m with pore pressure reaching 16.9 ppg (Scott, 2023).

The reservoir zones are located from MMU to the bottom of the Miocene strata with an initial stable trend of pore pressure and fracture gradient. There are five main sand zones interbedded with shales as follows:

- The A sand formation with an average gross thickness of 10÷18 m, the reservoir properties are quite good with fair permeability (average 34 mD), porosity is generally good to very good (average 24%) and high gas saturation in pay zones (10%). Within more than a decade in production, the monitoring of existing production and pore pressure prediction results had shown the average pressure of depletion is 90 psi per year.

- The B sand formation is a major production zone with an average gross thickness of 110÷250m depending on the well location. This thick section comprised clay units interbedded with shale sandstone layers of varying thickness. The reservoir qualities are quite good with fair permeability (average 47 mD), porosity is generally good (average 14%) and high gas saturation in pay zones (9%). The reservoir is comprised of interbedded shale therefore the

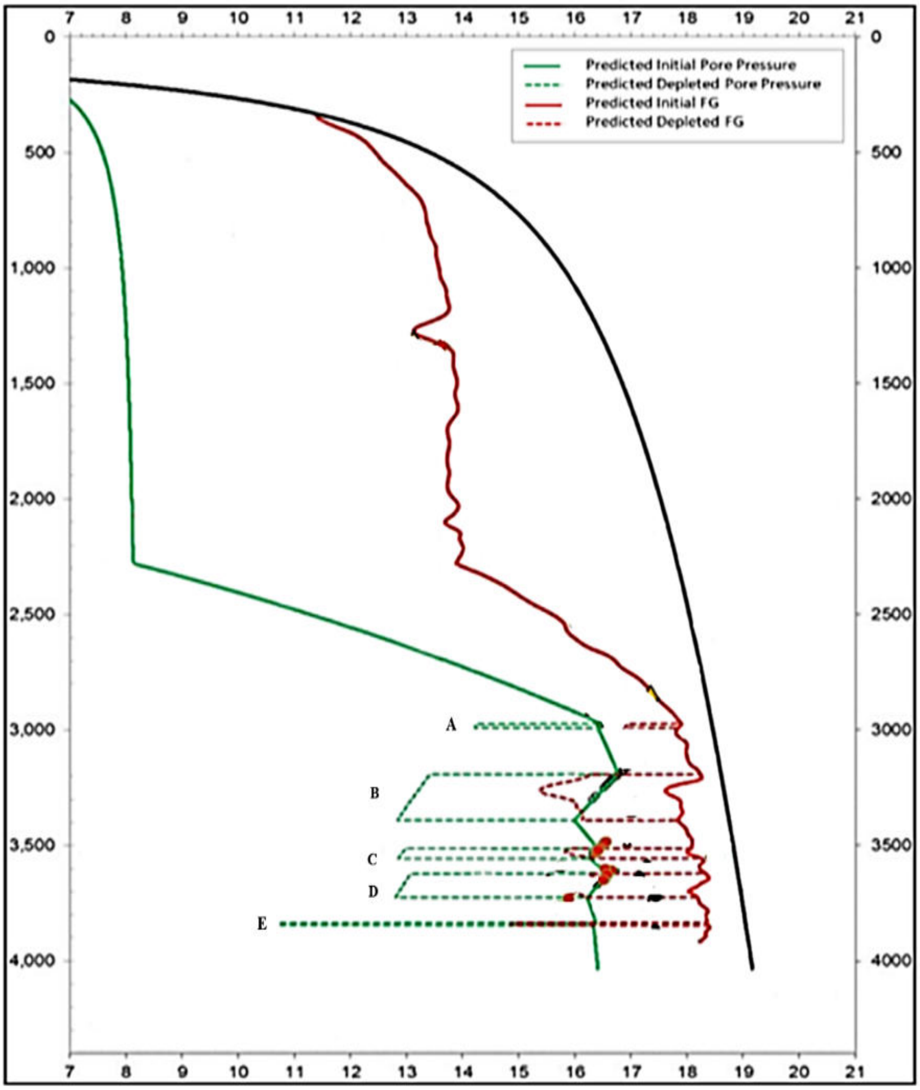

Figure 1. Predicted reservoirs depletion in the Nam Con Son Basin.

depletion of pressure occurred in this formation in various values, and maximum depletion will be at the bottom of the reservoir. The average pressure of depletion is 190 psi per year

- The C sand formation with a gross thickness of approximately 50÷70 m, the interval comprises a thin high porosity carbonate underlain by the interbedded sand and shale sub-sequence with high quality reservoir properties. The permeability (average 55 mD), and porosity are generally good with an average of 16% and high gas saturation in pay zones (35%).

In general, the properties of this formation are similar to the above sand formation with the average pressure of depletion is 190 psi per year.

- The D sand reservoir has a quite good gross thickness interval of approximately 50÷80 m, there are several reservoir quality beds. The permeability (average 50 mD), porosity is generally good with an average of 14% and high gas saturation in pay zones (30%). The properties of this formation are similar above sand formations B and C with the average pressure of depletion is 190 psi per year

- The E reservoir has a small gross thickness interval of approximately 10÷20 m, the permeability (average 12 mD), porosity is generally good with an average of 18% and high gas saturation in pay zones (25%).

The sand reservoir with small thickness and good porosity therefore the depletion of pressure in this formation occurred at a high rate. The average pressure of depletion is 290 psi per year. In general, the rock properties of the production reservoir in the Miocene strata have good porosity and permeability, and it seems that there is pressure communication; therefore, all of them have been depleted on a large scale.

1.2. Geomechanical model

The rock mechanic analysis was performed using the Geomechanical Model to measure the two main rock properties necessary to design the engineering while drilling the HTHP depleted wells:

- Fracture gradient of the reservoirs; and
- Borehole stability of the cap rock.

The initial fracture gradient (IFG) for HTHP wells in the Nam Con Son Basin was determined based on the LOT results of drilled wells and geomechanical modeling. It exhibits an upward trend from sand to shale formations, reaching its highest value at the shale cap rock just above the E sand formations. The IFG value can reach up to 18.4 ppg.

The fracture gradient profile at the production reservoirs is to be changed after production. Measurement of the fracture propagation gradient (FPG) which is close to the minimum horizontal stress and was measured by Geomechanical Model with the input data from production parameters, PLT and coring analysis, a summary of fracture magnitude is given in Tables 1 & 2.

The other information requested from rock mechanics was the borehole stability of the cap rock. This allows the definition of the minimum mud weight one can use without suffering unmanageable borehole instability of the open hole above. The result of minimum MW = 16.8 ppg was measured by Geomechanical Model, other information could be found in Figure 2.

2. The challenge for drilling infill wells and drilling technical solutions

2.1. Drilling challenges

It is a challenge to work in both engineering design and operations for HTHP wells in the Nam Con Son basin during the exploration and development phases. All of the high technical standards for drilling including equipment and procedures to be applied but the technical problems were occurred due to the aggressive geological conditions. However, drilling infill wells on the HTHP field after a signification depletion has occurred is more difficult. It requires penetrating through a long section with interbedded shale/sand reservoirs, the cap rock shale layer remaining at or close to virgin pressure and the sand reservoir with pore and fracture pressures have largely decreased due to production activities. In particular, there are no mud-weight windows exist anymore at the transition between cap rock and reservoir.

Table 1. Pore Pressure profile.

Reservoirs	Depth (mTVD)	Virgin Pressure (ppg)	Depleted Pressure (ppg)	Virgin Pressure (psi)	Depleted Pressure (psi)	Magnitude of Depleted (psi)
Zone A	2,950	16.4	14.2	8,254	7,147	1,107
Zone B	3,300	16.9	12.8	9,515	7,207	2,308
Zone C	3,500	16.6	12.8	9,913	7,643	2,269
Zone D	3,700	16.4	12.8	10,353	8,080	2,273
Zone E	3,800	16.2	10.8	10,503	7,002	3,501

Table 2. Fracture gradient profile.

Reservoirs	Depth (mTVD)	Virgin Fracture (ppg)	Depleted Fracture (ppg)	Virgin Fracture (psi)	Depleted Fracture (psi)	Magnitude of Depleted (psi)
Zone A	2,950	17.9	16.8	9,009	8,456	554
Zone B	3,300	17.6	15.4	9,909	8,671	1,239
Zone C	3,500	18	15.8	10,749	9,435	1,314
Zone D	3,700	18.4	16.5	11,615	10,416	1,199
Zone E	3,800	18.3	14.9	11,864	9,660	2,204

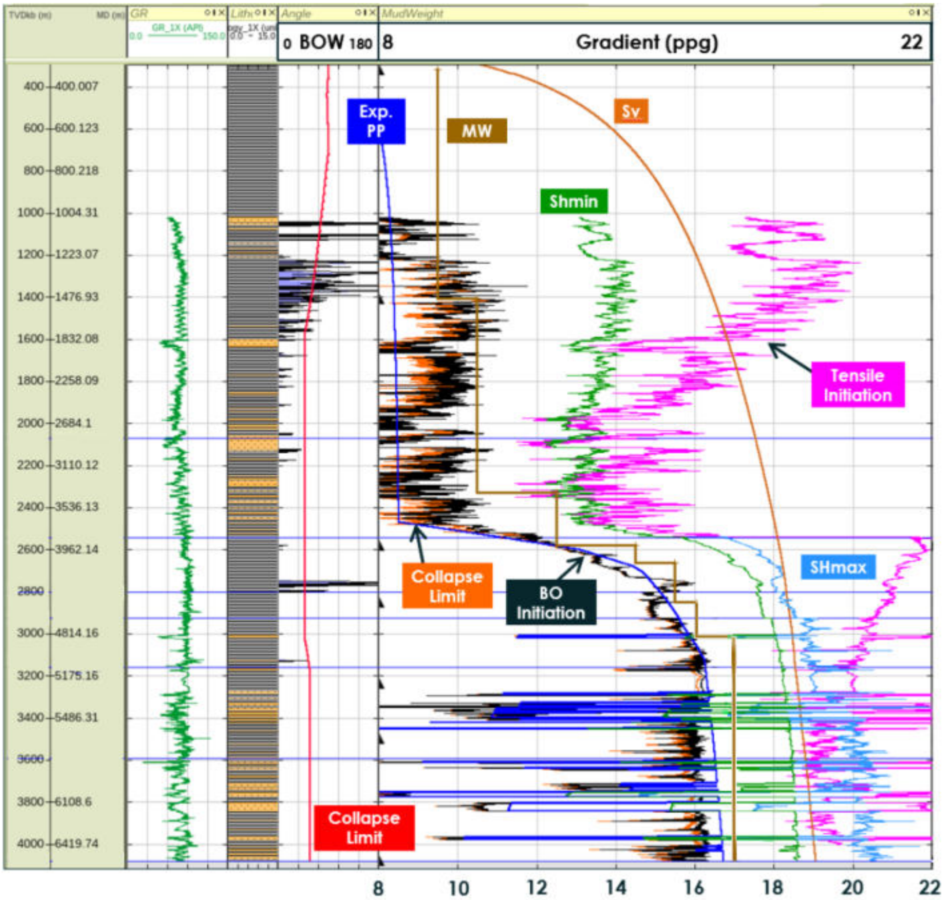

Figure 2. Rock mechanic properties.

The difficulty is further increased by uncertainties in the pressure profile along the well path, the rock mechanics and their change generated by the high and rapid depletion, and also by depth uncertainty on the top reservoirs.

On the other hand, the concept design of HTHP infill wells in the Nam Con Son Basin requires running one size of tubing through all reservoirs to minimize material and operational costs. Therefore, the infill wells in case of applying the conventional drilling methodologies have to face three major challenges as follows:

- Loss circulation: The depletion of production reservoirs is the cause of the decreasing fracture gradient. Meanwhile, the higher mud weight shall be utilized to drill through the cap rock layer where the pressure still maintains the original pressure. Therefore, the hydrostatic pressure created by mud weight will break the weak depleted sand formation, and the loss of circulation shall occur.

- Well kick: Technical problems could occur when the mud weight utilizes to drill upper reservoirs is lower than the pore pressure of below reservoirs. It also occurs when the well to be lost circulation which leads to the reduction of the hydrostatic column.

- Stuck Pipe: The well to be penetrated interbedded sand/shale formations with differences in pore pressure and collapse pressure value. The mud weight used for drilling shall be lower than the collapse pressure of cap rock which leads to the hole collapse. The depletion of pressure at reservoirs is caused by differential sticking suck pipe.

2.2. Consequence

Based on the analysis of challenges expected during the drilling, if conventional drilling methodology is employed for HTHP infill wells in the Nam Con Son basin, the following consequences may occur during the drilling and completion process:

- Unable to reach Total Depth due to drilling problems such as loss circulation, well kicks, and stuck pipe.
- Alteration of well structure necessitating the addition of casing/liner.
- Increased Non-Productive Time (NPT) due to drilling problems.
- Prolonged operation time leading to decreased project efficiency.
- Unable to run completion systems as design
- Lost well due to operations issues which impact overall project efficiency.

2.3. Proposed drilling technique for HTHP depleted well

The main goal of drilling activities for the HTHP infill drilling project is to minimize NPT (Non-Productive Time), project costs and HSE issues. The following drilling technologies have been found to have potential advantages concerning drilling in depleted reservoirs given in Table 3.

3. Application of wellbore strengthen methodology and MPD (Managed Pressure Drilling) system for HTHP wells

With the depletion levels shown in Figure 1, it could present some operational challenges such as the risk of differential sticking and lost circulation while drilling through the production reservoirs in Miocene strata.

Table 3. Comparison of drilling techniques or HTHP wells.

Drilling Technique	Application for HTHP depleted well	Advantages	Disadvantages
Wellbore strengthen & MPD	Yes	- Minimize the risk of drilling problems such as gas kicks, stuck pipes. - Minimize operation time. Reduction of NPT. - Could be applied to drill through multi-depleted zones. - Minimize the impact of damage to the production reservoir.	- The possibility of using incorrectly wrong-sized materials, which leads to loss of circulation. - High risk of the downhole tool and rig pump malfunction.
Casing / Liner drilling	Yes	- Minimize the operations time. - Reduction of NPT. - Improved wellbore strength by drilling cutting. - Could be applied for directional well - Minimize the impact of damage to reservoirs.	- Possibility to get stuck with liner before planned desired depth. - Could not be applied for drilling through production reservoirs with running lower completion systems. - Casing / Liner wear. - Poor cement or no cement behind the liner due to low fracture gradient.
Expendable Liners	Yes	- Minimize technical risk while drilling by isolating the depleted zones. - Mitigate problems with lost circulation and wellbore stability. - Possibility to maintain ID after setting liner. - Reduce the NPT.	- Need to apply other drilling methodologies for drilling the first depleted zone. - The big cost of expendable liner for 4÷5 depleted zones. - The possibility of failure increases when running a long interval for problem zones.

Table 4. Comparison of drilling methodologies for HTHP depeleted wells.

Drilling Methodology	Estimation of Operation per well (days)	Estimation of Cost per well (M USD)
Wellbore strengthen & MPD	88.5	48.7
Casing / Liner drilling	105.5	56.6
Expendable Liners	93.0	52.6

An effective evaluation was conducted for all proposed drilling techniques applicable to HTHP-depleted wells. The results indicate that employing a combination of wellbore strengthen methodology and MPD equipment not only resolves technical challenges during drilling but also in the engineering preparation.

Wellbore strengthening is a preventive methodology that is applied to deal with loss circulation and stuck pipes while working on engineering and MPD is a mitigating technique to be applied while operating (Ben, 2018).

3.1. The application of wellbore strengthening methodology in the Nam Con Son basin

The wellbore strengthening techniques have been extensively used as preventive methods in the drilling industry to prevent or mitigate drilling fluid loss. Wellbore strengthening attempts to bridge, plug, or seal wellbore fractures with lost circulation materials (LCM) such as resilient graphitic carbon, cellulosic fibers and marble to arrest the propagation of lost circulation in fracture(s) due to low fracture gradient. The pressure-bearing capacity of the wellbore can be enhanced by one or a combination of the following mechanisms in wellbore strengthening treatments:

- Bridge a fracture near its mouth to increase the local compressive hoop stress around the wellbore and enhance fracture opening resistance.
- Widen and prop a fracture to enhance the fracture closure stress that acts on closing the fracture.
- Form a filter cake in the fracture to isolate the fracture tip from wellbore pressure and enhance resistance to fracture propagation.

The requirement is to develop a well-strengthening program for HTHP-depleted wells in the Nam Con Son Basin, encompassing five (5) sand production-depleted reservoirs of varying scales, including Zone A, Zone B, Zone C, Zone D, and Zone E. However, there are similarities in the rock mechanical, pore pressure and fracture gradient in three major zones B, C and D. Therefore, in this paper, to minimize the scope of laboratory testing and modeling, authors assume that all parameters for input data shall be referenced to properties in Zone B.

On the other hand, in this paper, WellSET modeling shall be performed to identify the micron range of fracture width and engineered formulations with an appropriate particle size distribution (Gage, 2017). The input data to be utilized for modeling will be obtained from one indicated prospect. Therefore, the results of the modeling may not be directly applicable to drilling operations in all prospects in the Nam Con Son Basin but are intended for reference only. The required input data for modeling are as follows:

3.1.1. Drilling data

Based on the prediction of original pore pressure and fracture for HTHP wells in the Nam Con Son basin and the results of formation evaluation from offset wells, the well design concept "big bore schematic' shall be applied with an 8 ½" hole section penetrate production reservoirs and reach TD, lower completion including sand screen or 5 ½" perforation tubing shall be run. Therefore, the following drilling data is to be provided:

Hole size: 8 ½".

Reservoir Depth (m TVD): 3,250 m.

ECD value: The calculation of ECD based on the average hydraulic model.

ECD = MW + 1.4 ppg.

Drilling Fluid type of SBM with properties are given in Table 5.

Table 5. Drilling Fluid Property.

Drilling fluid properties for 8 1/2" section	
Type of Mud	SBM
Mud Weight	16.8ppg
Oil/Water ratio	75/25÷80/20
6RPM	10÷14
PV	< 40
YP	20÷30
FV	60÷80
LGS	< 5.0
HTHP filtrate	< 4.0
Water Phase Salinity	200÷300k
Excess Lime	> 3.0

3.1.2. Geomechanical data

The geomechanical studies were performed with offset well logs and geological data correlations to estimate the elastic rock properties. The following parameters from zone B shall be utilized for input data:

Poisson's ratio: ν = 0.25

Differential Pressure: Δp = 2,380 psi

Geomechanical data for zone B with 3 scenarios of depletion are given in Table 6.

Fracture length/width: Fracture length starts at 6 inches and also uses exponential distribution, as shown in Figure 3 below.

3.1.3. LCM formular design

The facture plugging shall be designed based on the D50 of the particle size distribution of the LCM and is set equal to the estimated fracture width. Sufficient particles in the range of smaller to larger sizes are present in the LCM packages and contribute to sealing a wide range of fracture widths

in the reservoir interval. The larger particulate also reduces the impact of continued mechanical attrition of particulate while drilling.

Based on the expected fracture window, the specialized LCM receiver assembly was used for the tests to measure the size of LCM and evaluate the efficacy of the various LCM packages proposed. The final formulations which get good results to be utilized in the range as follows:

- Resilient graphite with a concentration of 75%

- Sized ground marble with a concentration of 12÷25%

- Fibrous material with a concentration of 1÷12%

To select the proper formulation for the HTHP well in the Nam Con Son basin. LCM formulations were evaluated for both quantitative and qualitative evaluation purposes with the lab testing condition similar actual well condition.

Three (03) original mixed formulas #1, #2 and #3 were performed lab testing. Referring to the lab testing results and D50, D90, formula #2 was selected based on the particulate type and size, technical capability, available products and as well as the cost of the chemical.

From the original mixed formula #2, continued to optimize the mud loss pass-through by adding some more products to build the mixed formula #4 and #5. The mixed formula with D50, D90 results are given in Table 7.

With three (03) mixed formulas, the particle-plugging apparatus (PPA) test is to be performed for the measurement of mud loss pass-through in a similar bottom hole condition. The lab testing with ceramic disk slotted disc 500 µ with results is given in Table 8.

Table 6. Geomechanical data for zone B.

Property	Pore Pressure (ppg)	FG (ppg)	Static Young's modulus	Fracture Width (µ)
Original	16.8	18.2	0.38	0
Depletion 1	13.4	16.3	0.46	0
Depletion 2	13.2	15.5	0.55	145
Depletion 3	12.7	16.1	0.67	355

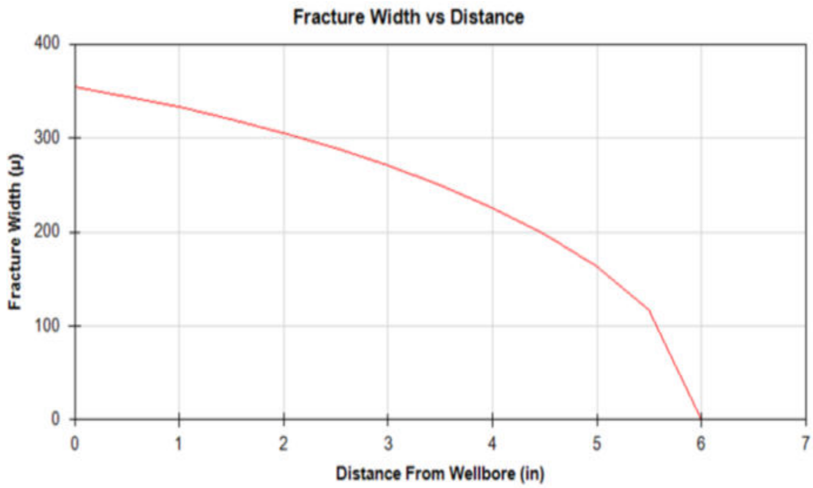

Figure 3. The proposed length & width of fractures.

Table 7. Lab Test result of LCM material formulars.

Formula	Product Treatment	D50	D90
#1	- Resilient graphite (A1) - 10 ppb - Resilient graphite (A2) - 5 ppb - Ground marble (B1) - 1 ppb	220	793
#2	- Resilient graphite (A1) - 10 ppb - Resilient graphite (A2) - 5 ppb - Ground marble (B1) - 2.5 ppb - Fibrous material (C1) - 2.5 ppb	261	1174
#3	- Resilient graphite (A1) - 10 ppb - Resilient graphite (A2) - 5 ppb - Fibrous material (C1) - 5 ppb	294	1,358
#4	- Resilient graphite (A1) - 8 ppb - Resilient graphite (A2) - 4 ppb - Ground marble (B2) - 2 ppb - Fibrous material (C1) - 5 ppb	251	1,174
#5	- Resilient graphite (A1) - 6 ppb - Resilient graphite (A2) - 2 ppb - Ground marble (B1) - 1 ppb - Ground marble (B2) - 1 ppb - Fibrous material (C1) - 5 ppb	330	1,678

Table 8. Particle Plugging Apparatus Results with slotted disc of 500µ.

PPA Results	#1	#2	#3	#4	#5
1 min, ml	0	0	0	0	0.2
7.5 min, ml	0	0	0	0	0.3
15 min, ml	0.6	0.5	0.6	0.8	0.5
30 min, ml	1.2	0.8	1.0	1.3	0.8
Total Whole Fluid, ml	2.2	1.8	2.0	2.6	1.6
Spurt, ml	0	0	0	0	0

Based on the lab testing results of PPA value, the mixed formula #5 was selected due to the value of mud loss after 30 mins, and Total Whole Fluid, ml is lowest compared to other formulas.

3.1.4. Procedure for pumping wellbore strengthen materials

Prior to penetrating through the first depleted zone in the 8 ½' hole section, the circulating system shall be treated by additions of wellbore strengthen LCM as per formula #5. The shaker screens API 10 scalper screens shall be addressed in order to maintain the LCM sizing and concentration in the circulating system.

The recommended drilling parameters while drilling through depleted zones are as follows:

- ROP: Limited 10÷15 m/hr to maximize sealing of fracture and perform LCT

- Flowrate: 300÷500 GPM to minimize the ECD and optimize the hole cleaning

- Solids control equipment was not run while drilling

- Hourly treatments of Wellbore Strengthening LCM to maintain particle size range in the circulating system.

3.2. Using MPD equipment for drilling through the depleted reservoirs

Refering to the definition made by the UBO committee of the IADC: Managed Pressure Drilling (MPD) is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. MPD is intended to avoid the continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process. It means that MPD can be stated as primary well control, and the bottom hole pressure while drilling shall be identified as follows:

$$BHP = MW + ECD + Backpressure$$

By keeping a relatively constant BHP during operations with adjust backpressure on the surface, the MPD could maintain the BHP in the range of pressure window (Fracture Pressure vs Pore Pressure)

MPD can provide solutions for mud loss which may occur as a result of pressure fluctuations exceeding the fracture pressure during tripping or connections. Depending on the severity of the loss and the mud used, this can be a costly problem. Loss of mud in the wellbore reduces the hydrostatic mud column which increases the chance of having a kick or in this case, mostly ballooning. By keeping a relatively constant BHP during the entire MPD operation, pressure fluctuations in the wellbore are minimized along with the risk of lost circulation.

A mud loss detected at the mud pits under conventional drilling may originate from several sources, including loss from solids, control equipment, surface leaks, or downhole losses. Consequently, a partial downhole loss may be attributed to another source and therefore go undetected until the situation worsens. MPD utilizes a closed pressure system where a detected loss could only originate from a downhole loss, which makes it possible for earlier identification of a lost circulation event. A remedial operation can be performed before the wellbore is beyond repair.

In the interpretation of pore pressure and fracture gradient for infill wells, the risk of a gas kick remains present when penetrating through sand reservoirs without communication with producing zones due to faults. The pore pressure magnitude in that reservoir is similar to the original pressure; therefore, gas influx may have occurred if there was a loss of circulation while drilling through the depleted zone.

The application of the standard operation manual for HTHP wells only applies to minimize the risk of technical issues while drilling a conventional HTHP well. With the depleted well, application of managed pressure while drilling (MPD) methodology is recommended (Ben, 2018) with the advantages as follows:

- The ECD while circulating is slightly overbalanced to prevent reservoir influx.
- Rotating Control Device (RCD) system allowed control of surface pressure.
- Close on the RCD during connection while bull heading at a slow rate to prevent reservoir influx.

With complex drilling operations occurring due to pressure depletion, the objective is to maintain bottom hole pressure just above the highest pore pressure while drilling through the cap rock and within the new fracture pressure created by wellbore strengthening. With the proposed mud weight for HTHP wells of up to 16.8 ppg mentioned by Avirup & Amita (2015), the required pressure equals the reduction in pressure with an assumed constant ECD of 17.0 ppg while drilling, which is equivalent to 0.2 ppg (PECD Constant - PESD) or (17.0÷16.8 ppg).

Based on the above requirements, it is recommended to utilize a full MPD with Auto Choke System including Coriolis meter, and early kick detection systems for drilling infill depleted wells in the Nam Con Son basin.

Based on the predicted magnitude of depleted pore pressure and fracture gradient after production duration, the proposed MPD systems with minimum requirement technical specifications could be worked for the drilling program as follows:

18 ¾" Rotating Control Device (RCD)

1,500 psi minimum pressure rating while drilling, stripping or rotating the drill pipe and 2,000 psi minimum pressure rating during static conditions.

MPD Automatic Choke Manifold and Panel requirement.

The working pressure rate is 5,000 psi. Working temperature minimum 100^0C.

The choke Manifold system must be fully compatible with MPD Automated Control System.

Flow line/ Piping/ Hoses/ Valve Equipment.

The design systems consist of piping, hoses, T pieces, elbows and associated valves to build the flow line as below:

Return line from RCD to upstream MPD choke manifold.

Injection line from Stand Pipe Manifold to RCD.

RCD bleed offline to rig mud trough.

Hole fill line from Trip Tank to RCD.

Flow line from downstream MPD choke manifold to rig mud trough.

Flow line from downstream MPD choke manifold to rig Mud Gas Separator and cuttings cleaning system.

MPD Automated Control System.

Enables Fully Automated BHP Control.

Includes integrated Data Acquisition System.

Includes MPD Early Kick Detection System.

Coriolis Meter and Bypass.

The Coriolis Meter is requested to provide the capability to measure return fluid density and temperature, which has a significant effect on circulating BHP when the MPD is applied. A bypass line on the meter skid also allows full fluid flow bypass, enabling the meter to be isolated with gate valves for maintenance.

Minimum working pressure rating 5000 psi, temperature up to 100^{0}C

Operating flow rate range: 50÷1,000 gpm

Unit Control

The Unit Control provides quick plug-and-play connectivity with all MPD equipment via a single power source.

Real-time monitoring of all surface recorded parameters such as flow rate, temperature and pressure throughout the MPD surface system

System display with audio-visual alarms for detecting instability events such as kicks, mud loss, choke plugging, circulation rate change, etc

Capable of applying constant bottom hole pressure as a method for managed pressure drilling.

Identifying and mitigating common drilling problems e.g. ballooning/breathing

Capable of performing dynamic formation-integrity tests (FIT) and leak-off tests (LOT) without the need to stop circulation or shut in the well.

The proposed MPD system to be set up on the jack-up rig is given in Figure 4.

4. Comparison of drilling methodologies for HTHP-depleted wells

4.1. The technical advantages and effectiveness of combination drilling methodologies

The overbalanced drilling normally applies for HTHP wells in the Nam Con Son basin with static mud weight that must be higher than pore pressure. However, when drilled through the depleted zones with no window between pore pressure and fracture gradient. Drilling into such a situation may lead to severe loss situations, which in turn may lead to kicks if the driller is unable to compensate for the lost fluids. Though it is possible

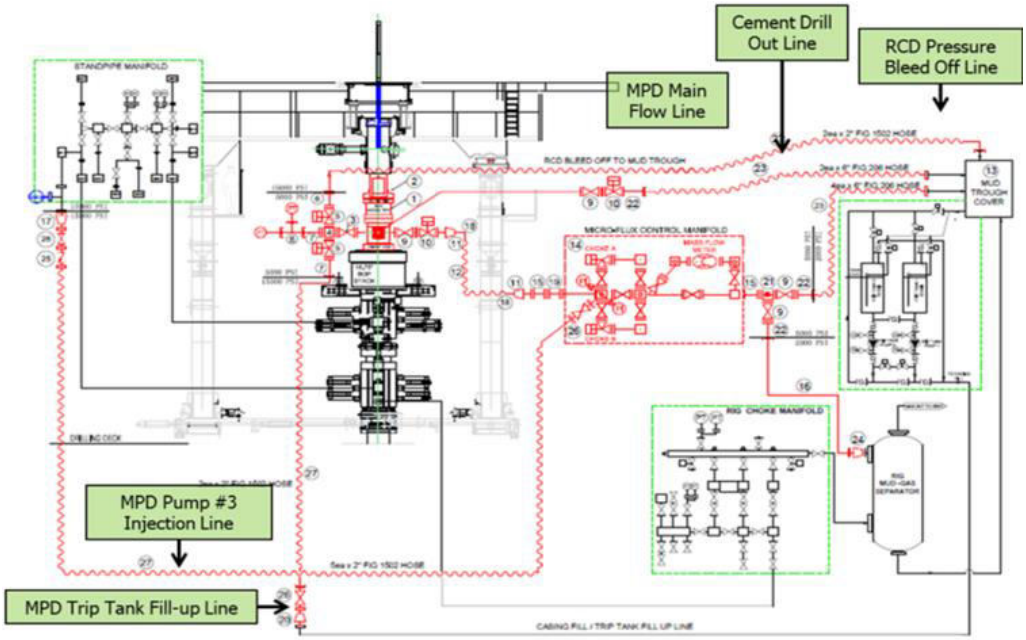

Figure 4. Proposed MPD system set up.

to drill wells while taking losses using fill-up annulus by drilling fluid, doing so consistently is not advisable for HTHP wells. On the other hand, the productivity of the upper reservoir which is still producing in this case is likely to suffer as a result due to fluid loss and fracturing, and it seems likely that the drilling process may be slowed down by stuck pipe issues and other operational challenges. In the worst possible scenario, drilling with losses may lead to kick/loss cycles, and lead to a blowout.

The application of combined methodologies wellbore strengthening and Managed Pressure Drilling (MPD), can significantly reduce operational risks while drilling. The primary function of each methodology can be identified as follows:

MPD: Maintains the bottom hole pressure at the desired value by managing back pressure. This minimizes the risk of well kicks and stuck pipe incidents due to differential sticking.

Wellbore Strengthening: Involves pumping wellbore strengthening Lost Circulation Material (LCM) while drilling through depleted zones to minimize the loss circulation rate which prevents the potential risks such as gas kick, stuck pipe and unable to reach TD.

A major technical advantage of using wellbore strengthening LCM for drilling through depleted production zones is that they are designed to seal fractures during drilling and cementing activities, and then be easily removed for production. These wellbore LCM do not impact skin or cause formation damage.

4.2. Comparison of drilling methodologies

The development plan for current oil & gas HTHP fields, including infill wells, normally involves drilling on the platform. Therefore, the divided wells shall be utilized for comparison in terms of both operation time and estimated well cost.

To compare drilling methodologies applied through depleted zones, this paper will focus solely on the comparison of drilling design and operations. Other well concept designs, such as well completion and well testing, will not be included in the comparison.

The comparison for drilling methodologies shall be performed based on the following assumes:

- Development/appraisal of HTHP well in the Nam Con Son basin
- The well structure consits of 30” x 20”x 13 5/8” x 9 7/8” and 8 ½” hole
- The depleted zones in an 8 ½” hole section with the TD @ 5,000 m mD / 4,000 m TVD
- There is no difference in design and operation for upper sections. The only difference in well design for the 8 ½” hole section drilling 800 m intervals through a depleted zone.
- The operation time for the well completion process of a total of 5.5 days for casing/lower completion jobs
- The jack-up rig shall be utilized on the platform for drilling
- The drilling services costs are based on the 2024 market survey
- The estimated well cost shall be calculated based on the spread cost per day

On the other hand, the estimation of drilling operation time shall be worked based on the average value in the Nam Con Son basin.

The comparison of drilling methodologies for HTHP depleted wells is given in Tables 3 and 4.

5. Conclusion & Recommendation

In the context of declining production rates from gas fields in the Nam Con Son Basin, along with an assessment of the effectiveness of the pipeline system from the gas fields to shore, the results indicate that drilling infill wells in the gas fields with depleted reservoirs to maintain the production rate is necessary. The application of the wellbore strengthening technique combined with utilizing Managed Pressure Drilling (MPD) equipment to minimize risks, NPT and enhance the efficiency of the project is a technical solution being considered to apply for drilling through the depleted reservoirs under HTHP conditions.

To maximize the efficiency of the application of Wellbore Strengthent and MPD techniques for drilling activities through the depleted reservoirs, the following recommendations are considered:

- The Pore Pressure analysis needs to be performed to identify the magnitude of initial pore pressure, fracture gradient and the amount of depletion in these reservoirs.

- The Wellbore Stability analysis shall be performed for specific directional wells which could have identified the rock properties to measure the fracture width and length.

- Laboratory tests for the selection of proper LCM material formula should be performed with the many different product types and sizes to maintain the proper plugging within a wide range of possible fracture widths.

- Further consideration should be taken to use a different drilling BHA and tools on these wells due to the downhole equipment limitations to pump LCM (size and concentration) and the required reduction in flow rate.

- Shaker screen size designation should be referred to the LCM properties and the industry standard API.

- The rig survey needs to be performed for installation of full MPD systems prior to operating.

- A Full MPD with Auto Choke & Automated Control System is recommended to utilize for drilling depleted wells.

Contributions of authors

Tai Trong Nguyen, Charles Dunne, Vinh The Nguyen, Thinh Van Nguyen - methodology, writing, review & editing; Tu Van Truong - review & editing.

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