AADE-20-FTCE-116

Lost Circulation Planning: What to Do When Rock Properties Change

Matthew Kratzer and Scott Thomassen, Newpark Fluids Systems; Mary Anne Ewanek

Abstract

Drilling in deepwater can generate a sizeable opportunity for operators, but it does not come without additional set of challenges as compared to onshore operations. Layers of depleted sands, create precarious situations which could result in lost circulation and, in turn, non-productive time (NPT). To mitigate risks an engineered lost circulation strategy needs to be customized.

To counteract the peril of drilling through depleted sands wellbore strengthening blends and pills were designed around fracture aperture estimates during well planning. These fracture apertures were programed into a computer model to create wellbore strengthening blends as well as pills. Blends were then vetted through laboratory testing. Finally, a Lost Circulation Material (LCM) decision tree was agreed upon to facilitate field execution.

During execution of the well total losses occurred in a known depleted sand. By following the pre-generated LCM decision tree, severe losses were completely halted. While this situation was ongoing, fracture apertures were recalculated based on the loss rate. The newly calculated apertures were larger than initial estimates therefore LCM blends needed to be revised. The pills in the original decision tree worked in static conditions; however dynamic conditions would exacerbate fracture size. During a 48-hour window in which operations was changing out the bottom hole assemblies (BHA), a new LCM decision tree for the depleted sand was formulated.

This paper will provide a comprehensive strategy from pre-planning for expected fracture apertures, to field execution as well as the creation of a broader plan once real time geomechanics information becomes available.

Introduction

Lost circulation is the uncontrolled flow of whole fluid into the formation. It can be caused by naturally cavernous fissured formations, induced fractures or coarsely permeable beds. Losses through induced fractures in permeable formations can be mitigated through wellbore strengthening techniques. Wellbore strengthening is the use of particles to seal and isolate fracture propagation and redistribute stresses around the wellbore. These particles act like a keystone in an arch increasing the hoop strength (Figure 1). Once the formation is subjected to stresses above the fracture closure stress (the minimum pressure required to keep a fracture open) a mechanically induced fracture occurs. An induced fracture is a result of a disproportionate stress distribution exceeding the fracture gradient causing the formation to fail under the load of the drilling fluid. Once the overbalance surpasses the resistance of the formation to propagate a fracture, losses heavily increase.

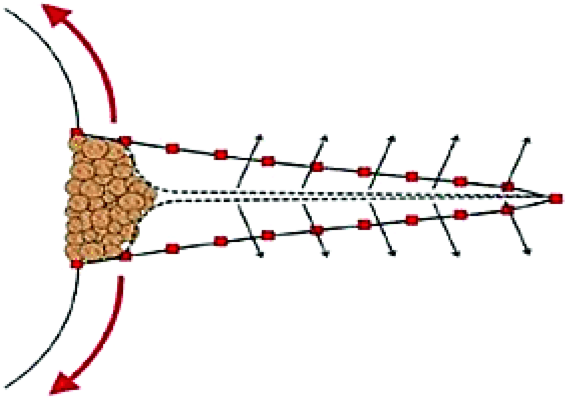

Figure 1 – Wellbore Strengthening, Distribution of Stress. (Vryzas 2017)

Deepwater drilling is a challenging environment, particularly for lost circulation. Having seawater (8.55-8.6 ppg) as a large layer of overburden inherently decreases stress regimes in successive geological layers, which in turn reduces resistance to fracturing. Besides the natural characteristics of drilling in deepwater environments, many of the formations have been produced for a long period of time and are highly depleted. Upon entering a depleted zone, the pore pressure and fracture gradient often decrease rapidly thereby creating a narrow operating window. This increases the potential of the downhole fluid equivalent circulating density (ECD) exceeding the fracture gradient (Bouguetta 20117). To avoid this situation fluids must be modeled around an accurate prediction of pore pressure and fracture gradients.

Deepwater predictions can be especially challenging because of the depleted sands that are encountered. Therefore, for this particular well, an LCM pre-plan was created through information from the geology and geomechanics team (G&G Team) of the operator, operational experience, and lab testing. This plan was a decision tree formulated for different loss rate ranges. Depending on the extent of losses different solutions were designed. This allowed for immediate response to losses since a plan, constructed in conjunction with lab and operational input, was already in place.

Losses, as specified by the operator, are grouped into four classes (Table 1). These classes can be defined differently depending on the operator but Table 1 provides commonly known loss rate categories. The G&G team models the average size of the fractures for different loss scenarios. Thus the range of loss rates might be consistent from well to well however the fracture size is not. Therefore solutions for each category must be tailored to the fracture size, so a "one size fits all" solution from well to well is generally not applicable.

Table 1 – Common Loss Ranges

Type of Loss	Typical Loss Rate (bbls/Hour)	Typical Loss Rate (m^3/Hour)
Seepage	10 - 20	1.6 - 3.2
Partial	20 - 50	3.2 – 7.9
Severe	50 - 150	7.9 – 23.8
Total	>150	>23.8

Laboratory Methods and Procedures

The deepwater well drilled and discussed here was particularly challenging. It would transition through numerous depleted sands with varying frac gradients and pore pressures. Each depleted zone had to have a LCM solution tailored to fit its particular characteristics. Through fracture estimates provided by the G&G team of the operator, an LCM decision tree was put in place through the joint effort of laboratory testing and operational input. The decision tree progressed from wellbore strengthening to out an out fracture plugging.

The G&G team modeled background or wellbore strengthening fracture widths to be 200µ, 500µ, and 1500µ. The different widths reflect transitions across various sands that have different pore pressures and fracture gradients. Due to uncertainty the maximum fracture width was estimated at 2000µ. LCM planning used the above fracture estimates to create LCM blends which were tested in the lab to determine effectiveness. Table 2 and Figure 2 display information provided by the operator to Newpark on potential fracture widths.

Table 2 – Operator Provided Modeled Fracture Widths

Distance from Wellbore (inches)	Fracture Width (microns, µ)
0	1125
2	972
4	723
6	0

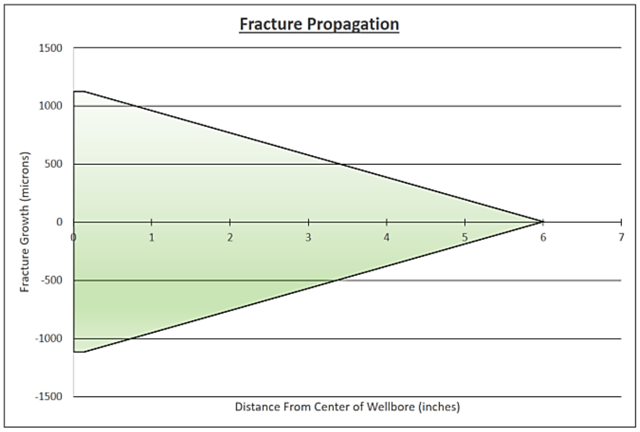

Figure 2 – Operator Provided Information on Modeled Fracture Widths

A slot tester was used for laboratory testing. The cell was loaded with a total volume of 350ml of fluid and LCM (See Figure 3). The fluid that was used was lab built. The cell was attached to a syringe pump filled with water. The pump used the water to push up the piston in the cell which applied pressure to the LCM laden fluid in the cell (See Figure 3). On the top of the cell a slotted metal disc with a slot the width of one of the four estimated fracture sizes (200µ, 500µ, 1500µ, and 2000µ) was placed (See Figure 3). A cap, which had a port that communicated ambient conditions of the lab was then placed on top of the disc.. As the piston in the assembly moved it pushed LCM laden fluid into the slotted disc. The goal was to seal off the disc and have it reach and maintain a target pressure (Figure 4). If the LCM blend was able to accomplish this the blend used became a potential solution for that particular fracture size. If not, the data was examined and the blend was redesigned. Through this lab work an LCM decision tree was formulated (Figure 5).

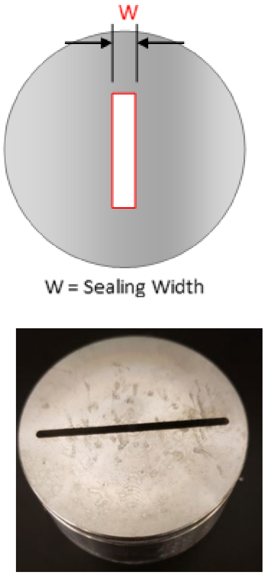

Figure 3 – Left (Syringe Pump) and Right (Slotted Discs)

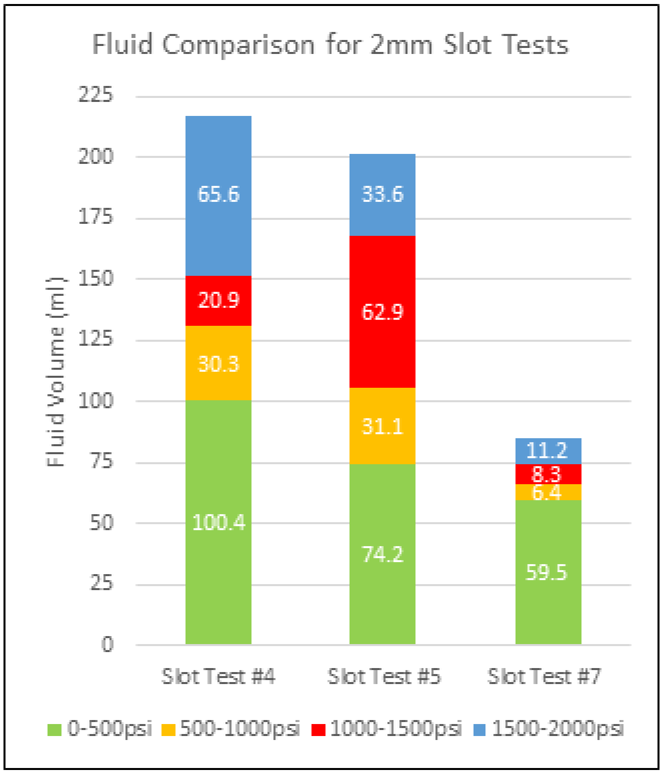

Figure 4 – Comparison of Fluid Volume Tests

From the lab to the field

These performance tests guide operations, but field feedback is essential for the optimization of blends. Laboratory testing gets the right materials to the rig while operations executes and adjusts LCM blends without compromising fluid conditions. It should be noted that there are a number of limitations to slot testing. Probably the most obvious is that a metal disc does not have the rock properties that will be experienced while drilling. The system is also open to atmospheric, so while there is a differential pressure it is not that of downhole conditions which has pressure on both sides of the fracture. The LCM used in the lab has a model PSD since it is acquired and measured in a controlled environment. The particles have not experienced a round of circulation and a path through the shaker screens. Some LCM is known for rapidly degrading and larger material can be scalloped off various solids control equipment due to its particle size (Amer 2017). Therefore it is essential to choose the optimal shaker stack to minimize loss of LCM as well as a program for maintaining the concentration of LCM in the active system.

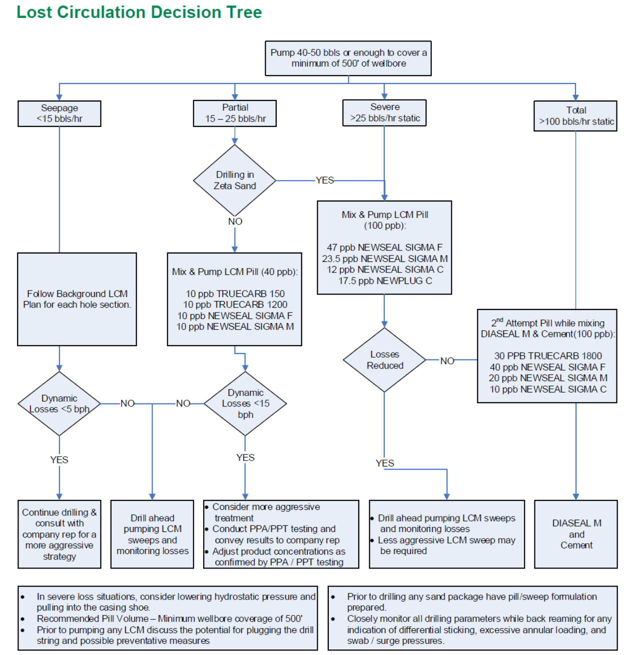

Figure 5 – Resulting LCM Decision Tree

Field Results

While drilling one of the depleted sands with a 10 5/8” bit and 12 ¼” reamer at a rate of penetration of 39ft/hr, there was a spike in torque and a drop in stand pipe pressure, which indicates a loss of returns. The bit was picked off the bottom and the well was shut in to maintain a full riser. To calculate the loss rate, one of the mud pits was isolated and the choke was opened to the system. It was determined from the pit that the well was taking 1,320bbl/hr, essentially a loss of all returns. The mud pumps were unable maintain fluid in the risers with the choke open so the well was shut in. It should be noted that losses this severe could have a number of consequences. By losing the hydrostatic column one might incur and influx of gas or fluids from the formation potentially causing a kick. Also the lack of fluid in the riser could compromise its integrity.

Implementation of LCM Decision Tree

The LCM decision tree allowed the operations team to quickly respond to losses. It was one of the many measures Newpark undertook to prevent or mitigate such incidences including prudent ECD monitoring and the use of low ECD fluids. Since the rate of losses was determined the appropriate pills corresponding with this particular loss rate were chosen from the LCM decision tree and pumped. Before the LCM pills were pumped the bypass sub was activated. The bypass has larger openings and also circumvents the smaller openings of the bottom hole assembly (see Figures 7 and 8). This allows for higher concentrations and larger sized particles of LCM to be pumped out of the drill string without plugging or damaging any of the complex tools in the bottom hole assembly.

Field Implementation Sequence:

The first pill to be pumped was the 40ppb partial losses pill at a volume of 100bbls. This was followed by the 100ppb moderate to severe losses pill at a volume of 149bbls. Once these pills were pumped down the string it was observed that losses dropped to 500bbl/hr. The next pill to be pumped was a 100ppb severe to total losses pill at a volume of 327bbls. While this pill was exiting the drill string wellhead pressure started climbing back to those observed prior to losses occurring. After this pill was pumped no losses were observed. See Table 3 for description of the pills that were pumped. Figure 6 gives the order of operation of the loss situation.

Table 3 – Description of Pills Pumped

Pill Type	Order of Pill Pumping	LCM Concentration (ppb)	Volume Percent of LCM per Barrel	D_{50} of LCM Blend (μ)
Partial Losses	Pill One	40	4.7%	472
Moderate to Severe Losses	Pill Two	100	14.3%	544
Severe to Total Losses	Pill Three	100	12.3%	704

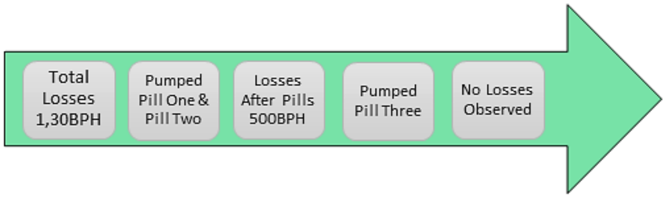

Figure 6 – Effect of Pills Pumped

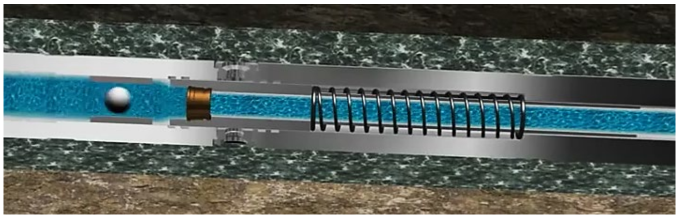

Figure 7 – Bypass Sub Before Activation (DSI 2015)

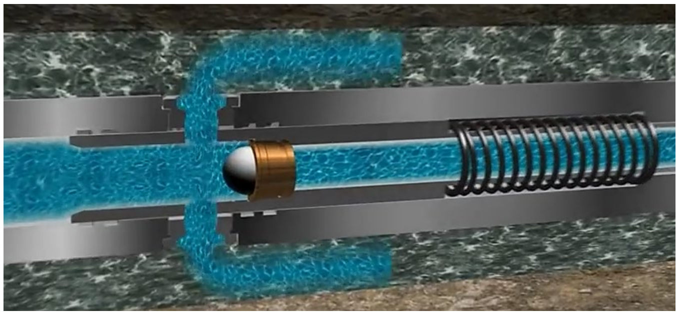

Figure 8 – Bypass Sub After Activation (DSI 2015)

Losses were contained in the static conditions allowing the operator to regain control of the well and making it safe to trip, run tubulars and cement this section (Therond 2017). That said, there was concern about possibly increasing fracture size once drilling resumed. Therefore, the decision was made to set a drillable plug just above the loss zone. The pipe was tripped out of hole in order to pick up the drillable plug. The plug was set just above the loss zone. Then, 150bbls of cement with 100bbls of de-fluidizing LCM was pumped and set with the plug. The de-fluidizing LCM helped prevent the cement from bleeding out into the formation and failing to set in the target area. After cementing, the drilling fluid was then circulated and conditioned with 20 to 25ppb of background LCM. Drilling was then resumed and this section was able to be completed on target without further losses. Also, the 9 3/8" liner was ran and cemented without down hole losses.

Mechanical Earth Model Calibration

The operator had the tools for measuring pore pressure while drilling. This proved essential in this particular well, since it incurred unexpected losses. The G&G team of the operator used this data to adjust models that calculated expected pore pressure and fracture gradients in the formations below the one experiencing losses (See Table 4). Thus they were able to utilize the information gathered in the loss zone to improve predictions of potential fracture widths in formations below, decreasing the likelihood of undergoing losses once drilling resumed. This information was essential to Newpark as it provided a foundation for developing LCM blends that would seal the new predicted fracture widths provided by the operator with much less uncertainty. In the three day window the operator was tripping to replace drilling assemblies, Newpark was able to complete lab testing for modified LCM blends to seal the adjusted fracture widths. A revised LCM decision tree was drafted by operations for the subsequent depleted sands below the loss zone. Once drilling was resumed there was no further losses the well was completed.

Table 4 – New Fracture Width Estimates

Type of Loss	ECD (ppg)	Fracture Width at Fracture Mouth (μ)
Case 1	14.4	2202
Case 5	14.8	3215

Conclusions

Because of the joint effort of the operator, Newpark operations, and Newpark labs a lost circulation event was mitigated by establishing a LCM decision tree before the incident actually transpired. A decision tree, could not have been established without the G&G team's prediction of potential fracture widths. This provided the "problem definition" for Newpark to utilize its operational experience and laboratory capabilities to provide LCM solutions. The operators open mindedness to Newpark solutions played a vital role in the LCM decision tree that became imperative when the well went on severe losses. Also, the operator's G&G team recognized the necessity of adjusting their model once real time data became available, which was crucial in the prevention of losses in subsequent sand zones below the loss zone. The G&G team predicted new fracture widths in the lower zones through data obtained while drilling and measured loss rates. These new fracture widths were used to design updated LCM blends to prevent losses in other sand zones. Because of these updated fracture calculations, and a new LCM decision tree, no losses were observed once drilling was resumed. Operations was able to quickly respond to losses minimizing and stopping it with LCM pills that were mixed and pumped according to their experience. Also once losses occurred they were able to adjust their hydraulics model to avoid further fracturing from occurring by predicting the behavior of the low ECD fluid. Operation's hydraulics modeling and a low ECD fluid played a critical role in the prevention and minimization of fractures on this well. Newpark labs was part of the trifecta of hindering and preventing further losses. By listening to the input of the operator and operations the lab was able to determine optimal LCM blends given a certain set of parameters. Once fractured widths were revised technical staff quickly resumed testing to provide new LCM blends with existing platform inventory. Altogether, the operator, operations, and lab were able to successfully reduce and prevent fluid losses.

Acknowledgments

The authors would like to thank and acknowledge the R&D and Operations teams at Newpark for working together on such a critical project and making it a key success for the client.

Nomenclature

NPT = *Non-productive time*
LCM = *Lost circulation material*
BHA = *Bottomhole assembly*
ECD = *Equivalent circulating density*
G&G = *Geology and geomechanics*
bbl = *oilfield barrel, 42-gallongs*
m^3 = *cubic meter*
μ = *micron, one-millionth of a meter*
ml = *milliliter*
PSD = *Particle size distribution*
“ = *inch*
ft/hr = *feet per hour*
bbl/hr = *oilfield barrels per hour*
ppb = *pound$_f$ per oilfield barrel*
D_{50} = *Average particle diameter by mass*

References

1. Amer, A, Sergiacomo, M., Carter, B.2017. “Common Misconceptions Regarding Lost Circulation Treatments.” AADE-17-NTCE-093, AADE National Technical Conference and Exhibition, Houston, Texas, April 11-12,2017. Available from www.aade.org.
2. Bouguetta, M, Guo, Q., Moffitt, J.D. “A Field Case Example of Wellbore Strengthening Design and Verification Process.” AADE-11-NTCE-26, AADE National Technical Conference and Exhibition, Houston, Texas April 12-14, 2011. Available from www.aade.org. Therond, E., Taoutaou, S. James, S.G., Way, P.W., Gomes, P. Dondale, A. 2017. “Understanding Lost Circulation While Cementing: Field Study and Laboratory Research.” SPE 184673, SPE/IADC Drilling Conference and Exhibition, The Hauge, 14-16 March 2017. https://doi.org/10.2118/184673-MS
3. DSI-PBL,. “DSI PBL® Sub (Circulating sub) Multiple Activation Bypass System.” http://www.dsi-pbl.com
4. Vryzas, Z.; Kelessidis, V.C. Nano-Based Drilling Fluids: A Review. *Energies* 2017, *10*, 540. https://doi.org/10.3390/en10040540
5. White, R.J. 1956. “Lost-circulation Materials and their Evaluation.” API-56-352, American Petroleum Institute, May 1956.
6. York, P., Pritchard, D., Dodson, J.K., Dodson, T., Rosenberg, S. Gala, D., Utama, B. 2009. “Eliminating Non-Productive Time Associated with Drilling Trouble Zones.” OTC 20220. Offshore Technology Conference, Houston, Texas, May 4-7, 2009. https://doi.org/10.4043/20220-MS