

Thixotropic Cement for Lost Circulation at Greater Mooses Tooth Alaska

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Abstract

Lost circulation is a significant challenge in the Greater Mooses Tooth region of the North Slope of Alaska. Losses occur while drilling the reservoir section which contains natural fractures of 2.5 cm (1-in) and larger. These fractured intervals result in partial and total losses increasing non-productive time (NPT) and compromising the ability to reach the planned well depth. Conventional approaches proved ineffective resulting in continuous losses. Thixotropic cement slurries have been described in the past as slurries that remain fluid while being sheared but begin to gel when shearing stops. The use of thixotropic cement slurries was successfully implemented in two wells.

The solution was developed in Prudhoe Bay and implemented using prior experience from North Sea drilling operations. Qualified by tests focusing on low downhole rheology, high thixotropic properties (30 min API Gel Strength) and short-term compressive strength development for pumpability and placement into the loss zone features. The goal for testing was to ensure pumpability through the bottomhole assembly (BHA) to reduce NPT. The thixotropic cement slurry was developed using additives commonly used on the North Slope of Alaska. Targets were based around downhole rheology (PV < 80 cP), 30 min API Gel Strength (>160 lbf/100ft²), compressive strength, (500psi < 15 hours), and focused on a totally dry blended system, which is best for Alaska logistics and operations. Ultimately the thixotropic system was pumped through the normal drilling BHA used to drill a 6 1/8" production hole. This paper will present the development and implementation to successfully treat severe lost circulation.

Introduction

Lost circulation is the loss of whole mud from the circulating system to a subsurface formation. It is a common problem encountered during drilling and completion operations, and the cost of lost circulation to the industry has been estimated to be billions of dollars. To mitigate errors, drilling engineers need a better understanding of lost circulation, lost circulation material (LCM), and treatments (Scott 2020).

The drilling fluids used generally have a normal distribution of particle sizes based on the solids control

equipment used on the rig. The use of LCM in fluids has misconceptions around type, size, and volume. LCM that is below 120 micron is ineffective due to the already abundant in the fluid. The use of large sized materials, with a D50 greater than 400 micron, has more value. When the use of conventional LCM fails, a high fluid loss squeeze or squeezing thixotropic cement is the next logical step.

Thixotropic cement slurries have been described as slurries that remain fluid while being sheared, but which immediately begin to gel when shear stops. A good thixotropic slurry mixes easily, but rapidly increases in viscosity both at room temperature and bottomhole temperature as the shear rate approaches zero. The increase in viscosity occurs repeatedly as the shear rate is alternately increased and decreased.

Greater Mooses Tooth (GMT) Alaska

The Greater Mooses Tooth (GMT) Unit is the first unit established entirely within the National Petroleum Reserve Alaska (NPR-A). The National Petroleum Reserve in Alaska (NPR-A) is an area of land on the Alaska North Slope owned by the United States federal government and managed by the Department of the Interior, Bureau of Land Management (BLM). It lies to the west of the Arctic National Wildlife Refuge, which is also federal land and managed by the U.S. Fish and Wildlife Service as a National Wildlife Refuge.

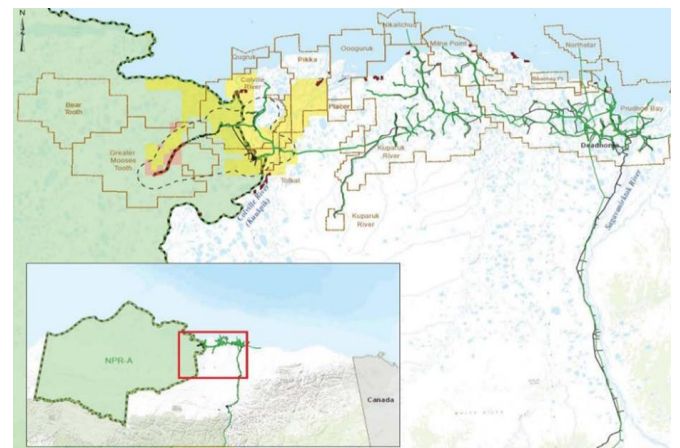


Figure 1 – Greater Mooses Tooth field, North Slope of Alaska

GMT was formed in 2008. In 2014, the company progressed development planning for the Greater Mooses Tooth-1 (GMT-1) drill site in the GMT Unit. Upon completion, GMT-1 was connected by road to the CD5 drill site and production will be transported by pipeline to the existing Alpine facilities for processing. Furthering the road led to expansion of the GMT project expanding to 2 pad locations.

GMT2 is the North Slope’s westernmost producing field, achieving first oil in 2021. The drill site is connected by road and pipeline to GMT1 and has development plans for 36 wells initially, with capacity for up to 48 wells. GMT2 consists of a 14-acre drilling pad, 8-mile gravel road, and pipeline facilities connected to existing infrastructure. The project was designed to minimize the footprint on the tundra and minimize environmental impact. GMT2 is expected to produce 140 million barrels of oil over the life of the field.

Some of the observations within GMT2 are the natural features as seen in Figure 2. This imaging gives borehole images that would normally not be seen with density logs. This near real time image log takes micro-resistivity measurements around the circumference of the well during rotation of the BHA showing features where major loss circulation occurred. This showed the extent of the natural features and gave light to the reasons for the lost circulation challenges.

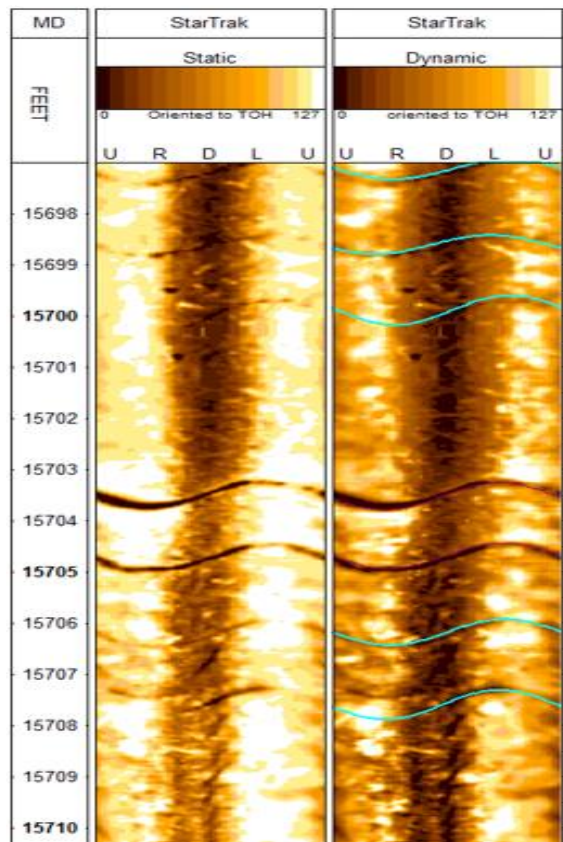


Figure 2 –Image logs showing large features.

In efforts to understand the lost circulation decisions

and where the lost circulation events occur the engineering team developed a map looking at the loss events locally within the wellbore and associated volume of losses at that time. With these prominent conductive fractures now evident with image logs of fracture aperture around the borehole engineering was now capable to generate both by location and by severity the lost circulation events. An example of the mapping in Figure 3.

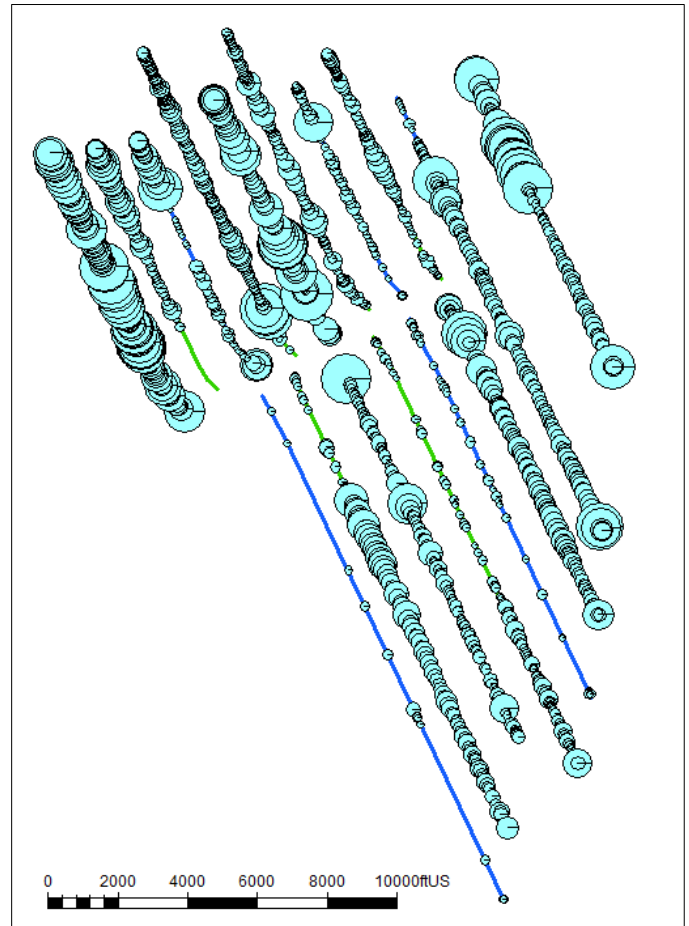


Figure 3 –Mapping of loss circulation

Conventional Lost Circulation Material

Lost circulation is one of the largest challenges that face drilling. The process of selecting the best lost circulation material (LCM) or treatment design may be different and not always dependent on the loss rate. Matrix type losses through permeability are usually easier to define as the permeability and porosity of the rock usually has some defined limits. With these limits, the basis of design for the drilling fluids program can include background bridging materials with the correct particle size distribution based on the porosity and permeability of the formation. Unless the drilling fluid is water or an ultra-low solids fluid, the use of smaller materials is rarely successful. These small particles are smaller than the solids already in the mud and would not be successful in sealing any noticeable loss zone to conductive fractures or faults (Bugbee 1953). These smaller LCM products can be detrimental to drilling fluid

properties and again only heighten mud properties that are being maintained like low gravity solids. This results in higher costs and more dilution to maintain suitable properties. With higher loss rates to features can be much more difficult to resolve. The size of the feature is usually unknown and basing treatment directly from a loss rate is misleading. There are some common practices and procedures that can be utilized in these events with various levels of success.

It is recommended to have a lost circulation decision tree based on local experience using readily available products. This allows for a validation point by using successes within the field to determine lost circulation treatments. In Alaska, this is especially important as most of the drilling occurs in locations without normal logistical routes to restock the LCM supply. Not only is it difficult to receive products, but the available space on locations or at a storage facility is limited. These concerns drive LCM products that are more utilitarian with particle size distributions on the larger side of the spectrum. These products show a higher success rate due to smaller particles already within the drilling fluid. While lost circulation decision trees are normally based on loss rate, they can be augmented with special treatments for specific known formations where losses often occur. The use of an LCM distribution or estimation of feature sizes can be made, allowing for a targeted LCM mix for the feature size.

General practice dictates to begin continual additions of granular materials. This is usually fine or medium walnut shells or calcium carbonate with a D50 larger than 400 microns at a recommended rate of 8 to 12 - 50 pound sacks per hour and go up or down based on results (Scott 2020). Walnut shells are preferred in Alaska due to lower cost, availability, and performance. Their shape has been shown to outperform more spherical calcium carbonate and graphite materials while withstanding circulation maintaining particle size. Calcium carbonate shear degrades quickly and should not be used for situations where the LCM is being recirculated (Jeennakorn 2017).

Low lost rate can be continuous additions to some sort of sweep or spot procedure, there are many factors that may cause the loss rate to be low. Drilling with a low differential pressure will cause lower losses than in a high differential pressure case was used. Under normal drilling parameters and using field knowledge of flow rates, differential pressure, lost rate dynamically and statically to can start to give direction of the treatment.

The next phase of the LCM decision tree is moving to some sort of sweep with added surface pressure when the sweep exits the bit. This has been a field level validation as it has seemed to work well in low to medium loss rates. These pills usually are blended materials with Walnut material designed so they can be pumped through the bottom hole assembly (BHA) and bit. As described, general practice in Alaska usually only allows for a dozen or so different LCM products due to space and logistics. This approach usually approaches the bounds of the acceptable PSD to pass through the BHA, MWD, and bit. These decisions usually allow for low medium and high loss events with a general approach.

Medium loss rates treatments begin with reduced mud weight/ECD if possible and begin additions of the largest granular materials that is allowed for the drill string and bit nozzles. This is usually a combination of medium and large nut shells or other granular LCM up to 2 mm and with use of bypass subs some situations may allow particles sizes up to 4 mm. This can be done with the spot and soak, slight squeeze, or background LCM treatment at a recommended rate would be fifteen to twenty fifty-pound sacks per hour. This is limited by personnel, ability to thoroughly blend material into the fluid, and volume availability. Use of materials above 700 microns with a D50 particle size distribution approaching 1,000 microns is preferred. Adjustments to the solids control system were evaluated and adjusted to maintain the LCM in the mud system. Usually, these larger size particles require a bypass sub in the BHA and will be opened to ensure the BHA and bit do not get plugged with LCM. If this treatment is not effective and the situation requires additional remedial treatments, a high-fluid loss high-solids hesitation squeeze would be appropriate.

High loss rates are clearly the most difficult lost circulation situation. The base case for Alaska has been to reduce mud weight/ECD if possible. Slow or stop circulation and work the pipe. Mix and spot a pill of the largest sized LCM blend through a bypass sub adjacent to the suspected loss zone. Then the BHA is pulled up above the LCM treatment while applying pressure. The pressure can be done with MPD choke, circulation above the spotted material, or closing the annular to apply pressure. Based on outcome if losses are still above 100 BPH continuation of conventional LCM or a high fluid loss squeeze.

The use of loss rates allows for further approaches and to judge the effectiveness and the financial path to continue treatment. If positive results are achieved continue with conventional LCM treatments. If conventional LCM treatments are not effective and rig operations allow, prepare a high fluid loss squeeze, and perform a hesitation squeeze. Establishing effectiveness is important to come back to the LCM tree and adjust the plan as results dictate.

The business unit was still unsuccessful. The harsh operational challenges faced by the drilling professionals in Alaska require extensive work processes to adequately plan and execute complex well designs including ERD wells (Dunn 2005). Engineers have a high focus on downhole technology and drilling technology, but lost circulation to this extent has been abnormal. Looking to other business units to see how they were able to effectively manage lost circulation, especially those that have features much too large for conventional LCM. This expanded the discussion on the use of settable products like thixotropic cement. Thixotropic cement slurries are a type of slurry that mixes easily, but which rapidly increases in viscosity both at room temperature and bottomhole temperature as the shear rate approaches zero. This increase in viscosity occurs repeatedly as the shear rate is alternately increased and decreased (Clement 1979).

Thixotropic Cement Used in Other Business Units

Wells drilled by this operator in the North Sea encounter frequent severe loss circulation events in both the overburden as well as in the reservoir sections. Overburden drilling includes narrow drilling margins and in the reservoir section there are often multiple severely depleted zones. With losses being common in both hole sections, the need for reliable lost circulation mitigation became obvious. The challenge is providing a solution that can be pumped through a directional BHA without tripping out of the hole placing it into the lost-circulation zone. Not only is the lost circulation a costly event, but there also needs to be a high level of focus on HSE and downtime (Johnson 2000, Zaman 2020).

Applications of thixotropic cement gave the desired focus and HSE attention to safely resume drilling with minimum downtime.

A solution was developed with the purpose of quickly mitigating the losses. Placement of the cement slurry is followed by a short WOC time before drillout can be performed and drilling progress allowed to continue, all of this with the same directional BHA still in the hole. The BHA's were optimized to allow for this with minimal risk to the operation. The operational steps, placement method, as well as the slurry design parameters were optimized based on field experience. This focus allows for squeeze application forcing the thixotropic cement into the features (Johnson 2000).

The technique was first introduced in the North Sea in 2013 and replaced gunk as the primary lost circulation treatment. Designed to be mixed on the fly with the cementing unit, the system does not require batch mixers or any unique additives. The wells with loss rates up to 1000 BPH, have been successfully treated with over 70% success rate.

The Service Partner Experience

Initial testing was set to evaluate systems with material existing in the Alaska portfolio. A multitude of systems were evaluated prior to testing and was limited down to several viable options. The parameters for the thixotropic slurry were as follows; downhole rheology (PV < 80cP), 30min Gel Strength (>160 lbf/100ft²), compressive strength, and (500psi approximately 15 hours). Density of slurries was evaluated based on experience with successful operations with the cement slurry being placed through the BHA without utilizing a bypass circulation sub (Zaman 2020).

All testing was performed with standard API Recommended Practice 10B-2. Initial assessment of available products started with currently used blends of cement: Extended G, Standard G with liquid additives, and High-Density G with liquid additives. All showed elevated plastic viscosity without the valuable trend of increasing gel strengths. The thickening time is evaluated to ensure downhole conditions that are present will not affect the pumpability of the slurry. While the focus around the compressive strength of the test is to define the ultimate strength of the cement remaining low but at the same time filling the loss feature keeping it isolated (Fomenkov 2019).

Achieving a cement slurry with the low preferred downhole rheology and 30min Gel Strength was the largest obstacle. After rounds of testing, a base blend of cement and Gypsum was showing the best results and was focused on for the remainder of the testing as seen in Table 1 and 2. The focus for the slurry should rely on a low PV with gels that build with time.

Table1: Basic Cement Slurry

Slurry	Units	Extended G	Standard G with Liquid Additives	Higher Density G with Liquid Additives
Density	lb/gal	13.0	15.8	16.5
BHCT	deg F	182	182	169
300	deg	68	102	198
200	deg	53	77	143
100	deg	34	48	79
60	deg	24	34	50
30	deg	15	21	28
6	deg	5	7	7
3	deg	3	5	4
10 sec Gel	lbf/100ft ²	4	5	5
10 min Gel	lbf/100ft ²	10	21	38
30 min Gel	lbf/100ft ²	35	53	72
PV	cP	65	97	196
Ty	lbf/100ft ²	7	10	7
Thickening Time	70 Bc	9:29	5:49	5:12
Compressive Strength	50 psi	12:15	9:39	14:23
Compressive Strength	500 psi	17:53	11:22	15:32

Table 2: Thixotropic Cement Slurry

Slurry	Units	Thixotropic v1	Thixotropic v2
Density	lb/gal	14.0	14.0
BHCT	deg F	188	168
300	deg	98	65
200	deg	93	61
100	deg	86	57
60	deg	82	55
30	deg	72	53
6	deg	30	29
3	deg	25	21
10 sec Gel	lb/100ft ²	27	17
10 min Gel	lb/100ft ²	51	53
30 min Gel	lb/100ft ²	257	161
PV	cP	51	33
Ty	lb/100ft ²	57	38
Thickening Time	70 Bc	4:37	6:18
Compressive Strength	50 psi	6:43	13:01
Compressive Strength	500 psi	9:40	16:36

All materials used for this system were readily available in the Alaska market and would reduce the lead time for any usage of the solution. Throughout the usage of the thixotropic slurry, several iterations of the blend have been used to achieve the desired properties: including additional of a viscous modification agent, increase of density, and modification of retarders present in the blend. Below is a chart looking at the shear rate vs shear stress of the 5 different blends showing the pumpability of the two thixotropic cement blends. See below in Figure 4 the ability for the Thixotropic to maintain a flat shear rate vs shear stress.

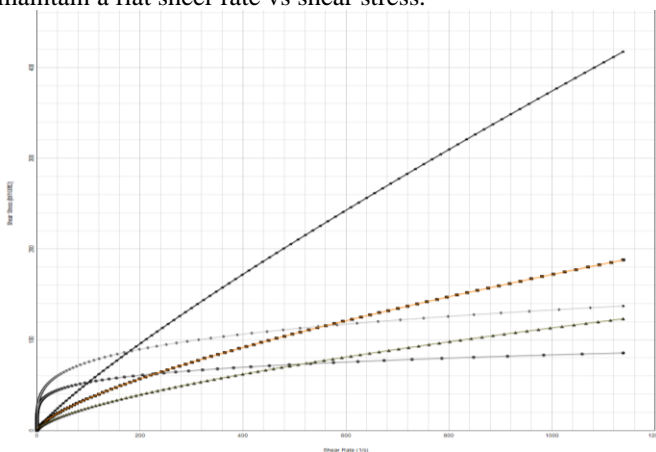


Figure 4 –Shear Stress over Shear Rate: This is to show that thixotropic was developed to become flat but build viscosity at low shear rates.

Case Study #1

The production section of the well was planned to drill into known losses and could see higher mud weights than previously experienced. The first part of this section was drilled towards the base of the Alpine C formation where several faults and fractures were drilled through. Losses were observed at 120 BPH. Attempts were made to heal losses with thirteen conventional LCM and one high fluid loss squeeze that was unsuccessful. Based on prior lessons from other business units, a decision was made to trial thixotropic cement. The decision was made to drill to a depth of 19,500' MD and then pull out of hole to pick up a cementing assembly to be used to pump and squeeze a thixotropic cement blend from the intermediate shoe to heal the lost circulation before drilling to total depth. Before coming off the bottom, two 100 bbl pills containing LCM consisting of 105 ppb were spotted in the open hole.

The drilling assembly was pulled out of the hole and laid down. A bit was picked up and run in hole on drill pipe. The bit was run to TD to ensure that nothing had bridged off in the open hole that could lead to the cement bridging off before hitting a loss zone. Once at TD the work string was pumped out of the open hole to the 7" Intermediate #2 Liner shoe. Static and dynamic loss rates were determined to be 20 BPH and 60 BPH, respectively and establishing injection rates at 2 BPM, an increasing pressure trend was observed. These data points indicated that the losses had been healed to some extent. This created a risk of the cement bridging off earlier than expected, possibly with cement inside the work string.

Due to this concern, the BHA was run back to bottom and a static and dynamic loss rate was determined (with fluid flowing past the loss zone). The loss rates were as follows:

Table 3: Case History #1 Loss Rates

Pump Rate	Loss Rate
Static (hole fill)	0 – 12 BPH
3 BPM	100 BPH initial reduced to 24 BPH
4 BPM	18 BPH
5 BPM	70 BPH
6 BPM	132 BPH

The bit was pulled out inside the 7" liner shoe, and loss rates and injection rates/pressures were re-established. The cement crew pumped 37 bbls of 12.0 ppg spacer at 4 BPM then swapped over to 133 bbls of 14.0 ppg Thixotropic Cement at 5 BPM. The annular preventer was closed at 75 bbls of cement pumped. This volume was chosen based on the modeled cement free-fall. The plan was to have the annular shut when the spacer exited the bit. Then pumped 15 bbls of 12.0 ppg spacer at 5 BPM followed by 12 bbls of freshwater at 5 BPM followed by 210 bbls of 8.8 ppg RDF WBM. Performed spot/squeeze cement with an Initial pump rate of 8 BPM to catch cement soon reduced to 5 BPM once cement was caught.

The cement was given 10 hours from cement being pumped to reach 500 psi compressive strength. After 10 hours

the pumps were staged up to 252 gpm with the bit at the 7" shoe to establish parameters. A dynamic loss rate of 30-40 BPH was observed at all stages of staging up.

Tripped BHA in hole to 15,200' MD where a 20K lb. tag was observed. Circulation and signs of cement (increase in pH, scent, density) were observed from a bottoms up of 15,200' and continued through the entire trip in. The highest density observed being returned to surface was 9.2 ppg. No un-contaminated cement was returned to the surface.

However, the cement that was circulated out of the hole became extremely strung out. Once on bottom, the hole was circulated clean of cement and LCM. Then established loss rates where no static losses were observed and circulating losses were 36 BPH at 6 BPM. The MPD RCD bearing was installed, and the bit was stripped out of the hole to 16,920' MD where the static loss rate increased to 18 BPH. A 120 ppb LCM pill was mixed and spotted before continuing to strip out of the hole. Once at the top of the 7" liner, the RCD was removed, and the BHA was pulled out of hole to surface.

The cement assembly was laid down with little to no cement debris on tools. The drilling assembly was made up and run in hole where the bit tagged at 16,700' MD. From there the bit was washed down (w/o rotation). Cement contamination was observed and treated. No hard cement was observed while washing down. The loss rate while washing down at 170 gal/min was ~20-25 BPH. Losses increased to 60 BPH at 190 gal/min with an ECD of 9.3 ppg. A 50 bbl @ 35 ppb LCM Pill was circulated. The pill was pumped through the BHA below the powerup flow rate of the tools. This pill reduced losses from 60-80 BPH to 30-40 BPH. Drilling progressed continuing with supplemental LCM treatments. Although the thixotropic cement did not stop losses altogether, it lowered our loss rate (both static and dynamic), and it allowed conventional LCM to be effective.

Case Study #2

The production section of the well began with a mud displacement to 8.8 ppg water-based reservoir drill-in fluid inside casing without issue. The shoe was drilled out and 20' of new formation was drilled without losses. Expectations of multiple loss zones and fractures were encountered, and conventional LCM treatment was started with the use of medium sized walnut shell at 5 ppb. Due to the loss rate not improving use of a 35 ppb LCM pill was pumped managing the loss rate allowing for drilling operations to continue. Upon an increase in loss rates over 100 BPH at a depth of 20814' MD a bypass sub was opened, and a conventional LCM pill was deployed 100 bbl. of 60 ppb with continued loss rate. At total depth of the well, 22794' MD, losses were 30-70 BPH. After cleaning up the well, the string was stripped out to 13405' MD. The drilling BHA was pulled and LD. Multiple clean out attempts were made unsuccessfully. The decision was made to abandon the lower portion of the wellbore and sidetrack below the surface casing shoe.

The production sidetrack BHA was picked up and shallow tested successfully. The liner was drilled out to 5' above the shoe and displaced to 8.8 ppg water-based reservoir

drill-in fluid. Twenty feet of new hole was cut and an 11.9 ppg EMW LOT was conducted. Extreme losses were expected and encountered while drilling the production section. Initially 35 ppb LCM pills were pumped to keep drilling ahead at a manageable loss rate.

The bypass sub was opened at 14067' MD to pump a more aggressive 100 ppb & 120 ppb LCM pills but they were ineffective. The decision was then made to strip out of hole to the shoe and pump thixotropic cement through the drilling BHA. Use of the MPD system to squeeze cement would give the rig control over downhole pressures. The rig established injection rates at 2-4 bpm and bullheaded 130 bbls of thixotropic cement. After this squeeze was performed, pressure was bled off and 20 bbls was bled back before shutting back in. Static loss rates while WOC were 30-40 BPH. The string was washed back to bottom and the well was drilled to a total depth of 21015' MD with 20-30 BPH. losses. When the BHA was laid down, very minimal cement was observed on the tools. This ability showed a valuable time savings showing a large step change towards pumping thixotropic cement through a drilling BHA.

Case Study #3

This well was a planned work over opportunity to clean out a well that was drilled earlier in the campaign. The 6-1/2" cleanout assembly was picked up consisting of a cleanout BHA. The string was washed and reamed to 13161' MD where an obstruction was encountered and experienced high torque and pressure. The well was circulated and worked down to 13350' MD where a pack off was encountered and the well went on losses. The BHA was then pulled back to the shoe in preparation to pump Thixotropic cement.

Injection rates were established at 2-4 bpm and 110 bbls. of 14.5 ppg Thixotropic cement was pumped through the bit and bullheaded downhole. A hesitation squeeze was conducted but pressure bled off after the 3rd squeeze. An attempt was made to open the bypass sub, but it would not open. Later findings showed it was due to rubber material getting caught in the seat. Loss rates at this point were 30 BPH. The initial intent was to TIH to the loss zone and place two balanced plugs bringing the second inside the existing 7-5/8" casing. While TIH the string took weight at 12405' MD. The decision was made to pump conventional LCM was bullheaded and stopped losses. A single balanced plug was placed with 43 bbls. 16.5 ppg Class "G" allowing for a sidetrack.

A 6-1/2" RSS kick off assembly was picked up and TIH. Cemented was tagged at 11469' MD. The string was washed and reamed to 11644' MD, 20' below the shoe. The string was pulled back into the shoe and a shoe test was performed to 12.1 ppg EMW with 8.8 ppg fluid. The sidetrack was successful, the BHA was then POOH and LD same.

A new 6-1/2" production BHA was picked up and washed to bottom. The drilling fluid left in the hole was then displaced to a new 8.8 ppg RDF. While drilling ahead 130-140 BPH losses were encountered at 13570' MD. A conventional 50 bbl 35 ppb LCM pill was pumped and reduced losses to 20-

30 BPH. This loss zone correlates with the known feature in the original well. A second loss zone was encountered at 14952' MD and the well went on total losses. An attempt was made to drill past the zone to 14803' MD, but losses did not subside. The bypass sub was opened and a 100 bbl 100 ppb conventional LCM pill was pumped and slightly squeezed reducing losses to 40 BPH. After drilling ahead to 15182' MD losses again picked up to 120 BPH. Again, the bypass sub was opened placing 100 bbls. of 100 ppb conventional LCM. The pill was bullheaded but did not hold pressure once in place.

The BHA tripped to 13000' MD, ~500 prior to the first known loss zone. Injectivity rates were established at 2-4 BPM and 125 bbls. of 14.5 ppg thixotropic cement was pumped through the drilling BHA. This well was slightly different from experience as a cement swivel was picked up and used allowing for the thixotropic cement to be placed closer to the loss zone. Thixotropic cement was then bullheaded leaving some cement in the wellbore. This is the first time was pumped through the bit in the open hole. The decision was then to go to the intermediate shoe while waiting on the cement. The static loss rate was 48 BPH waiting for 100 psi on the cement compressive strength plus two hours prior to washing back in the hole.

The well was then drilled to TD at 19100' MD maintaining 5 ppb background medium walnut shell LCM in the active while seeing 40-80 BPH losses. At total depth the well was circulated clean seeing dynamic losses at 75 BPH. The BHA was laid down in preparation for the 4-1/2" lower completion liner run where it was recorded as no ill effects on pumping thixotropic cement.

Conclusions

Observations and real time data driven decision making allowed for successful implementation of a technique to combat the losses seen in the North Slope operations. Below are some lessons learned during implementation.

- Testing: Plan to batch and test cement blend at the end of intermediate section due to testing time.
- Blending: use rock catchers to prevent clumps or unblended materials from entering the BHA.
- Logistics/supply: movement to dry products with high shelf life for Alaska remote operations.
- Pumping: Ensure pump rate stays below MWD/LWD activation threshold. Cement may create a vacuum due to increased density. The fall rate should be considered along with using MPD to hold squeeze and offset u-tube pressures.
- Placement: When pumping a long distance from the loss zone, expect a fair amount of residual cement when staging in after pumping and using a larger volume of cement. Mud contamination will be an issue. Pumping from the safety of the shoe may not always be possible depending on where the loss zone is encountered. When treating closer to the loss

zone cement volumes should be minimized.

- Lost circulation materials: on high loss rates additional LCM treatment can be made after successful squeeze of thixotropic cement this aid in filling voids.
- Post Job: Target more than 50 psi compressive strength prior to washing through cement. Displace mud after washing through cement and before drilling. Expect higher torque after cementing.

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Nomenclature

API = American Petroleum Institute
Bbls = Oilfield barrels
BHA = bottomhole assembly
BLM = Bureau of Land Management
BPH = barrels per hour
BPM = barrels per minute
cp = centipoise
BLM = Bureau of Land Management
D50 = Median Particle size
ECD = equivalent circulation density
ERD = Extended Reach Drilling
EMW = equivalent mud weight
GMT = Greater Mooses Tooth
HSE = Health, Safety, Environmental
LCM = Lost Circulation Material
LD = Laid Down
LOT = Leak Off Test
LWD = Logging while drilling
MD = Measured Depth
MPD = Managed Pressure Drilling
MWD = Measurement While Drilling
NPR-A = National Petroleum Reserve Alaska
NPT = Non-productive Time
POOH = Pulled out of the Hole
PPB = Pound per barrel
PSD = Particle Size Distribution
PSI = Pounds per square inch.
PWD = Pressure while Drilling
RCD = Rotating control device
RDF = Reservoir Drillin fluid
RSS = Rotary steerable system
TD = total depth
TIH = Tripping in the Hole
TVD = true vertical depth
w/o = With Out

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