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Designing Fluids for Wellbore Strengthening – Is It an Art?

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Abstract

Increased drilling in mature fields has heightened interest in finding new and better ways to overcome problems associated with drilling in depleted zones. Present solutions to the problems associated with drilling depleted zones are either remedial or preventive. The preventive method involves ways of strengthening the wellbore during drilling to stop fractures from growing and becoming unstable. Growing fractures result in significant mud losses and can lead to well control problems.

On-the-fly preventive methods appear to be favored as they cut down on non-productive time and reduce costs in the longer term. These methods involve mechanical or chemical means of sealing induced or natural fractures while drilling in overbalanced conditions. While the chemical approach to real-time wellbore strengthening may still be in its early stages of development, the mechanical method is already well developed and has been used successfully in many applications.

The mechanical approach to real-time wellbore strengthening involves the use of carefully selected loss prevention materials (LPM), which serve two functions: they prop fractures and seal them against wellbore pressure. This dual function creates additional tangential stresses around the wellbore (hoop stresses), thus increasing the fracture pressure gradient, and prevents fracture growth. Successful application of the technique, now known widely as the Stress Cage Technology,[2-4] depends strongly on the design of the LPM-laden drilling fluid. This paper describes the required properties and the steps involved in the design of the fluid and the LPM. Examples will be given of optimized systems for different types of drilling fluids. Finally, the authors will present a case history where an optimized LPM-laden fluid was used to successfully strengthen the wellbore and mitigate mud losses.

Introduction

In drilling highly depleted zones, often the hydrostatic pressure in the wellbore exceeds the fracture gradient of the formation and promotes the risk of induced fractures and subsequent mud losses. Preventing significant mud losses and avoiding well-control problems requires good planning and drilling practices together with appropriate wellbore strengthening solutions.

Wellbore strengthening solutions may employ one or more of the mechanical, thermal or chemical means of increasing the fracture gradient of the formation. The mechanical solutions use additives in the mud system to plug and seal induced fractures to increase the compressive tangential stresses in the near-wellbore region. The thermal solution relies on the thermal gradient between the wellbore fluid and the formation to heat up the rock and increase the tangential stresses around the wellbore. This method is suitable for stiff formations with high thermal expansion coefficients and is thought to increase the fracture gradient by about 120 psi for a 20ºC rise in wellbore fluid temperature.

The chemical solution may include chemical potential gradient towards the wellbore, *e.g.,* salinity gradient, to strengthen the near-wellbore formation. Recently, there have been advances where certain chemical reactants are delivered downhole and made to react into products with gelling or setting properties to plug pores and fractures, thereby strengthening the wellbore.

The mechanical solutions are by far the most frequently used method of wellbore strengthening. They fall into two categories of remedial and preventive approaches. In the remedial approach, a high-solids-content pill is squeezed into fractures after losses occur. Widening the fracture is the main objective of the treatment scheme, which helps build the maximum fracture closure stress (FCS).[1] The treatment is effective in permeable formations, which allow the liquid part of the pill to drain away, leaving behind an immobile mass of solids. For low-permeability formations, hesitation squeeze has been recommended, which fills the fractures with an immobile mass over several attempts and a longer time period. The hesitation squeeze treatment does not require carefully selected or specialized solid materials, and water-based pills may be used in a non-aqueous system.

The preventive mechanical approach is based on the Stress Cage theory which is a method for strengthening the wellbore wall and increasing the fracture resistance of the formation while drilling.[2-4] A major application of this technique is in depleted reservoirs where the reduction in pore pressure has weakened the formation. The on-the-fly preventive method appears to be favored as it cuts down on non-productive time and reduces costs in the longer term.

In the Stress Cage concept, wellbore strengthening is achieved by allowing fractures to form in the wellbore wall, under the prevailing pressure overbalance, such that they act as wedges to compress the rock within a zone (the Stress Cage zone), changing the "stress state" around the wellbore. For the Stress Cage approach to be effective, the induced fractures must be kept open by propping with specially designed LPM.

By performing a finite element analysis of the Stress Cage concept, Alberty and McLean[4] were able to conclude that the magnitude of the additional stresses created around the wellbore is a function of the formation stiffness, the width of the fracture, the position of the bridge within the fracture, the length of the fracture, and the compressive strength of the LPM. To increase fracture width, the LPM bridge should form near the mouth of the fracture. For the treatment to be effective, the pressure within the fracture must deplete quickly to allow the fracture to close behind the bridge. Therefore, the method is more effective in permeable formations. In low-permeability rock, the LPM bridge will need to provide a perfect seal to prevent pressure transmission into the fracture and fracture propagation. Aston *et al.*[3] suggested that such application would need a drilling fluid with very low filtercake permeability, *i.e.,* an "ultralow fluid-loss mud", and described ways of achieving such a goal.[5]

In summary, the magnitude of the created fracture gradient rise depends on the type and concentration of the LPM, the particle size distribution of the additives relative to the desired fracture width, and the fluid loss characteristics of the LPM-laden drilling fluid. This paper describes the required properties and the steps involved in the design of a fluid for depleted zone drilling. Examples will be given of optimized systems for both water-based and invert-emulsion fluids. Finally, a case history will be described briefly where an optimized LPM-laden fluid was used to stabilize the wellbore and to reduce mud losses when drilling through sequences of overpressured shale and depleted sands.

LPM Design

The first step in designing the optimum LPM for a given application is to estimate the fracture width needed for creating the desired increase in fracture gradient. Alberty and McLean[4] developed a finite element model for estimating the required fracture width from rock mechanical data and wellbore pressures. Alternative approaches have been used by others to produce similar information.

The LPM should contain particles of a size capable of bridging the fracture mouth. The higher the concentration of such particles in the LPM, the lower the required loading of the LPM. Alberty and McLean[4] estimated the required LPM loading by suggesting that there should be one such particle for every portion of fluid equal to the fracture volume. The fracture volume is calculated by assuming a triangular prism-shaped fracture the height and width of the target fracture.

Frequently, the particle size distribution (PSD) of the selected LPM may not be capable of providing an effective seal in the bridge, which is needed to restrict pressure transmission from the wellbore to the fracture and prevent fracture growth. In such cases, the PSD of the LPM should be modified with the addition of one or more other materials. Algorithms utilized for PSD optimization for reservoir drilling may be used for this purpose. This should provide a blend of two or more materials that contain the appropriate loading of particles needed to plug the fractures and minimize fluid loss to pores with an average size equal to the estimated fracture aperture. The loading of particles that are the size of the target fracture may need to be increased if other materials have been added to reduce fluid loss. The final PSD should have the ability to plug and seal fractures of the predicted width, provided that the base mud formulation has optimum fluid-loss properties.

Fracture performance studies conducted in our labs have shown that graphitic materials and calcium carbonates, individually or in combination, can plug and seal fractures as wide as 1 mm. In some instances, inclusion of a hard cellulosic material enhanced the mechanical strength of the bridge and provided a better seal against higher mud pressures.

Laboratory Testing

Blends of LPM were optimized to determine the maximum fracture width and seal pressure that could be obtained with the fracture model described below. Three examples are given. The first example illustrates the optimization process for the design of LPM for a KCl/polymer water-based drilling fluid. The optimization will use calcium carbonate LPM to produce a depleted zone drilling fluid that has good fluid-loss control over a range of matrix permeability and that can plug and seal relatively wide fractures created in a laboratory fracture model. The second example uses carbon-based materials for developing LPM with similar characteristics for an invert-emulsion fluid. In the third example a combination of carbonates and graphitic materials are used to design an LPM for an invert-emulsion fluid of higher mud weight.

The effectiveness of the LPM blends in reducing HTHP fluid loss across a bridge was tested on API paper and on ceramic discs of different permeability. As preliminary investigations revealed that API filter paper and low-permeability discs did not give enough differentiation between different LPM blends, moderate- to high-permeability ceramic discs were used for this evaluation.

The fracture performance of the LPM-laden fluids was tested in a fracture model with impermeable faces.[6] The fracture faces were circular in shape and made of aluminum, had concentric corrugations and a uniform separation. LPM-laden fluid was pumped into the fracture at a constant rate of 0.5 mL/min though a hole in the center of one face. The fluid flowed radially outward between the two faces. Fluid (or filtrate) flowed out of the fracture and was removed at variable rate (0 – 0.5 mL/min) by a pump that maintained a constant tip pressure of 25 psi (simulating pore pressure). Pumping of the mud raised the pressure in the fracture and increased fracture width. Fracture width was measured by a pump that applied a constant closure pressure of 125 psi. The starting fracture width in most tests was 530 microns. The fracture model capabilities were limited by the mud pump (1,200 psi maximum pressure) and by the maximum particle size that could be used in the system (<1 mm) resulting from blockage of tubing, pumps, etc. This put a practical limit on the PSD of particles that could be considered as LPM. To avoid repeated problems of blockage, the choice was limited to materials whose maximum size (*e.g.* d_{99}) was below 1 mm. This meant that the maximum achievable fracture width was somewhat less than 1 mm and that, based on the discussion of the previous section, relatively high loadings of the LPM had to be used to achieve the target width.

In the fracture model, bridge formation occurred as the LPM-laden fluid flowed radially from the center to the outer edge of the fracture. This reduced the rate of outflow of fluid from the fracture (equivalent to leak-off) and led to an increase in mud pressure, which in turn increased fracture width. **Fig. 1** is an example plot of the test data vs. time. It shows: (red trace) mud pressure increases at an accelerating rate (indicative of bridge buildup and resistance to mud flow, *i.e.,* a good seal); (green trace) fracture width increases (increased mud pressure forces the fracture faces apart); (blue trace) the volume of fluid removed from the fracture increases until an effective bridge is formed and then remains more or less unchanged. This is equivalent to seepage of fluid into the fracture; if allowed to continue this can result in fracture propagation. Such fluid flow out of the model fracture is referred to as conductivity or leak-off.

The radial position of the bridge in the fracture depended on the PSD of the LPM. In most cases, once the fracture width increased beyond that supported by the LPM, the bridge collapsed, mud pressure fell and the fracture width decreased. If pumping continued, the process would start all over again. In some tests, the maximum mud pressure and fracture width increased in subsequent cycles.

Example 1: LPM for Water-Based Fluid

These tests were carried out for a KCl/polymer water-based fluid and a low-toxicity mineral-oil-based invert-emulsion fluid. The base mud formulation for the two fluids are given in **Tables 1** and **2**.

The optimization of LPM for the two fluids started from the premise of finding a strong material of adequate size to plug the widest fracture obtainable in the fracture model. For the water-based fluid this appeared to be a medium/coarse calcium carbonate with d_{90} = 689 micron and a d_{99} approaching 1 mm. The required concentration was calculated to be about 50 lb/bbl. The LPM-laden fluid exhibited high fluid loss. This was improved by replacing part of the coarse carbonate with a fine cellulosic fiber material (d_{98} = 297 micron) and a very fine calcium carbonate (d_{90} = 9.8 micron). This optimization was achieved by using a PSD optimization software as described in the previous section. However, in fracture tests, the seal pressure produced by this blend (A) was low and a relatively large volume of fluid passed through the LPM bridge. In a further test the fracture performance of the blend was boosted by incorporating a fine grade of a hard cellulosic material (crushed nutshell) with d_{90} = 600 micron. As discussed below, the new blend (B) was highly effective in widening the fracture and increasing seal pressure.

The contents of the two blends (A and B) are given in **Table 3**. The rheology of the fluid containing blend A is given in **Table 4.** Presence of relatively large particles of the nutshell in blend B prevented its rheology measurements with the conventional R1-B1 rotor-bob geometry of the Fann 35 viscometer due to the narrow gap between the bob and the rotor.

The HTHP fluid loss of the muds containing the two LPM blends are given in **Table 5** and illustrated in **Fig. 2**. The results show that both blends of LPM are very effective at reducing the HTHP fluid loss on API paper. On 150-µm aloxite disc the values are higher but that is not unusual for a water-based fluid at such temperature and using a high-permeability medium. Inclusion of the nutshell increases fluid loss but not to a drastic extent.

The fracture performances of the two blends are shown in **Table 6**. The results show that inclusion of nutshell in blend B widens the fracture close to the limit of the device and raises the mud pressure to about 1,000 psi. The results also show that bridge formation is quick and that relatively little fluid passes across the bridge. The data for blend B are shown in graphical form in **Fig. 3**.

Example 2: LPM for Invert-Emulsion Fluid

LPM blend optimization for the invert fluid of **Table 2** involved various combinations of different types of LPM. Extensive fracture performance studies on LPM-laden fluids showed that graphite and graphite/industrial carbon blends were particularly effective in producing a good bridge and high seal pressure. Therefore, a graphite/industrial carbon blend was used as the base for LPM optimization in invert emulsions. An LPM grade with a d_{90} = 600 micron was chosen as the base material for the final LPM blend (d_{10} = 60, d_{50} = 200). As with the water-based system, calculations showed that around 50 lb/bbl of this material may be needed for effectively plugging and sealing a 1-mm fracture. However, fluid loss measurements on high-permeability discs showed that some PSD optimization was required to reduce losses. As a result, part of the graphite/carbon blend was replaced by a fine cellulosic material (d_{98} = 297 micron). An extension of this blend included a fine grade of crushed nutshell as described earlier. **Table 7** gives the components of LPM blends C and D used in the invert-emulsion fluid of **Table 2**.

The rheology data for the fluid containing LPM blend C is given in **Table 8**. It is interesting to note that the relatively high loading of graphitic material in blend C does not have an impact on the rheology of the fluid. This is not usually the case with the carbonate materials. As with the water-based system, the presence of coarse particles in the crushed nutshell prevented rheology measurements for blend D.

PSD optimization for the blends was performed to reduce fluid loss on high-permeability matrix. This led to low HTHP fluid-loss values on API paper and on a range of ceramic discs. This is illustrated in **Fig. 4** for the fluid containing LPM blend C. It is interesting to note that for the 190-µm aloxite disc most of the fluid loss occurs as spurt, after which the rate drops significantly. The fluid containing LPM blend D gave similar fluid-loss performance.

The fracture performance of LPM-laden invert fluid is given in **Table 9**. The effectiveness of the graphitic material can be seen in the performance of blend C. It forms an effective bridge and produces a seal pressure of 425 psi. However, because of its particle size limitation it increases the fracture width by only 25 microns. In contrast, blend D, which contains crushed nutshell, can plug and seal a wider fracture (an increase of 107 microns). It also produces a two-fold increase in seal pressure. For both systems, fluid flow across the bridge is limited and the time to seal the bridge is relatively short.

Example 3: LPM for High-Mud-Weight Invert Fluid

The objective in this example was to design an LPM, for an invert fluid (18.3-lb/gal mud weight and 90/10 oil/water ratio) to plug and seal fracture apertures of 600 to 800 micron. It was decided to use coarse carbonate for plugging and creating width, and a graphitic material for providing a good seal. The carbonate of choice for creating width was a special grind coarse calcium carbonate. The PSD of this material indicated that 55% of the particles were equal to or larger than 800 micron. On this basis, preliminary calculations suggested that about 10 lb/bbl of the material would be needed to plug fractures of 800-micron aperture. To provide effective fluid-loss control, a PSD optimization algorithm was used to determine the final LPM blend. **Table 10** gives the quantities of the components of the blend. **Fig. 5** illustrates the excellent match between the optimized blend and the target PSD calculated by the algorithm.

The fracture performance of the 18.3-lb/gal invert fluid containing the optimized LPM is given in **Table 11** and illustrated in **Fig. 6**. The bridge formed by LPM blend E generates very good seal and after a short time stops flow of fluid into the fracture. The fracture width that is bridged is within the target range of 700-800 micron. Effective plugging and sealing of the fracture has resulted in a mud pressure increase of 900 psi. **Fig. 6** also shows the performance of blend F, which contained nearly twice the amount of LPM. The performance improvement caused by this increase appears to be minimal. It generates 50 psi higher seal pressure and, as expected, bridge buildup is only slightly faster.

From the above it is clear that by balancing the components of an LPM blend in terms of particle size distribution, type (*e.g.,* strength, shape) and concentration, it is possible to produce a fluid for depleted zone drilling that has acceptable fluid-loss control and that can effectively plug and seal induced fractures to allow the drilling operation to continue.

Case History

The 12¼-in. interval of an offshore well was to be drilled through intermittent sections of high-pressure shale and depleted sand. To stabilize the wellbore while drilling through the shale, a higher mud weight than could be tolerated by the depleted sands had to be used. Data from offset wells suggested that mud losses in excess of 6,000 bbl should be expected. It was decided to use the Stress Cage approach to strengthen the wellbore as the well was being drilled through the interval.

Because of varying permeability and formation strength, the pressure overbalance was different for the various sections in the interval, resulting in different induced fracture apertures and requiring different particle sizes for plugging and sealing of the fractures. Calculations using geomechanical data and wellbore pressures gave estimates of fracture apertures ranging from 180 to 650 micron. Two blends of LPM were optimized for the application. One was for the widest fracture, *i.e.,* 650 micron, and the second for a mean fracture width of 415 micron in the expectation that the final LPM blend would contain sufficient particles of smaller and larger sizes to plug and seal the narrower and wider fractures. The LPM was to be used in an invert-emulsion fluid with density 10.0 to 11.3 lb/gal.

It was decided to use a combination of graphitic and carbonate materials to create width and an effective seal in the fractures. Particle concentration calculations were based on the PSD of a graphitic material containing 19% particles equal to or larger than 650 micron and 30% particles that were equal to or larger than 415 micron. The estimated concentration of the graphitic material corresponding to the two fracture sizes were 21.4 lb/bbl (for LPM blend G) and 8.7 lb/bbl (for LPM blend H), respectively. For each option, the final LPM blend was obtained by PSD optimization and included two grades of calcium carbonate of smaller size to fill the gaps between the graphitic particles and minimize fluid loss across the LPM bridge. **Table 12** gives the particle size data and concentrations for the optimized LPM for the two options.

The fracture performance data for the invert-emulsion fluids containing the two LPM blends G and H are given in **Table 13**. The results show that blend G with a higher concentration of the graphitic material creates a wider fracture and can support higher seal pressure. It also provides a better seal in a shorter time. However, in view of the expected pressure overbalances and the reservoir permeability in this application, it was decided to opt for LPM blend H, which contained a lower concentration of the graphitic material.

The 7,217-ft interval was drilled successfully without major hole problems. Mud losses during drilling were reduced to about 400 bbl compared to more than 6,000 bbl in offset wells. During drilling the bit was pulled out of the hole several times to check the bit and BHA for signs of wear. Each time, the trip out of the hole and return in the hole was trouble free. Mud properties and hole cleaning remained good while drilling the entire interval.

Additions of the Stress Cage materials were made continuously on an hourly basis to maintain the required level in the mud. The configuration of the shaker screens had to be modified to retain a good part of the LPM in the mud. The low-gravity solids were controlled by running centrifuges at intervals. It was concluded that, in addition to mitigating mud losses, the LPM also helped torque and stick-slip during the entire interval.

Conclusions

On-the-fly mechanical wellbore strengthening has been argued to be a favorable solution for mitigating mud losses and avoiding well-control problems when operating in pressure overbalance conditions.

The design of LPM to create a Stress Cage requires careful selection of the type and concentration of particles such that the right balance can be achieved between propping induced fractures of a critical size, minimizing fluid loss into fracture to prevent fracture propagation, and the effect of particles on fluid rheology.

The steps involved in the design process for the LPM has been discussed, with examples for water-based and invert-emulsion fluids. The performance of the LPM has been evaluated by using a unique fracture performance device. Tests performed with this device indicate that graphitic materials may be more effective in propping fractures while carbonates and cellulosic materials can improve the seal of the bridge.

A recent case history is discussed where a specially designed LPM was used to drastically reduce mud losses, which were expected to be several thousand barrels based on data from offset wells.

Acknowledgments

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Nomenclature

Define symbols used in the text here unless they are explained in the body of the text. Use units where appropriate.

BHA = *Bottomhole assembly*
LPM = *Loss prevention material*
FCS = *Fracture closure stress*
PSD = *Particle size distribution*
HTHP = *High-temperature, high-pressure*
μm = *micron*

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Table 1 – Formulation for 11.0-lb/gal KCl/Polymer WBM

Product	lb/bbl
Freshwater	309.0
Xanthan	1.25
Defoamer	0.2
Biocide	0.2
Temperature stabilizer	0.5
KCl	26.5
Fluid-loss additive	7.0
Clay	10.0
Barite	124.0

Table 2 – Formulation for 80/20 Oil/Water Ratio, 9.5-lb/gal Invert Emulsion Fluid

Product	lb/bbl
Mineral oil	195.8
Primary emulsifier	4.55
Secondary emulsifier	4.55
Organoclay	5.0
Lime	6.0
Fluid-loss additive	1.5
Calcium chloride	21.8
Freshwater	60.9
Barite	99.1

Table 3 – LPM Blends Optimized for Table 1 WBM

LPM	Concentration (lb/bbl)			
	Medium/Coarse Carbonate	Very Fine Carbonate	Fine Cellulosic Fiber	Fine Crushed Nutshell
A	20	10	20	-
B	20	10	20	10

Table 4 – Rheology for WBM Containing LPM blend A

Fluid		Fann readings at 120°F						PV	YP	Gels	
		600 rpm	300 rpm	200 rpm	100 rpm	6 rpm	3 rpm			10-s	10-min
Base + A	BHR*	100	77	66	51	22	19	23	54	18	22
	AHR*	74	57	49	40	17	14	17	40	14	19

* BHR and AHR: Before and After hot rolling for 16 hr at 250°F.

Table 5 – HTHP Fluid Loss of LPM-Laden WBM of Table 1

Fluid	HTHP Fluid Loss at 250°F, 500 psi (mL)			
	150-micron aloxite disc		API paper	
	spurt	30-min	spurt	30-min
A	2	17	0.5	1
B	2.5	12	0.7	2

Table 6 – Fracture Performance Data for the LPM-Laden WBM

LPM	Conc. (lb/bbl)	Mud Press. (psig)	Max Width (µm)	Conduction (mL)	Time to Seal (hr)
A	50	73	530	12.8	0.32
B	60	998	848	3.3	0.07

Table 7 – LPM Blends Optimized for Invert-Emulsion Fluid of Table 2

LPM	Concentration (lb/bbl)		
	Graphite/Industrial Carbon Blend	Fine Cellulosic Fiber	Fine Crushed Nutshell
C	40	10	-
D	40	10	10

Table 8 – Rheology for Invert-Emulsion Fluid Containing LPM blend C

Fluid		Fann readings at 120°F						*PV*	*YP*	Gels	
		600 rpm	300 rpm	200 rpm	100 rpm	6 rpm	3 rpm			10-s	10-min
Base + C	BHR*	60	34	25	15	4	3	26	8	6	8
	AHR*	59	34	26	16	6	5	25	9	6	10

* BHR and AHR: Before and After hot rolling for 16 hr at 250°F.

Table 9 – Fracture Performance of Invert-Emulsion Fluid Containing LPM Blends C and D

LPM	Conc. (lb/bbl)	Mud Press. (psig)	Max Width (µm)	Conduction (mL)	Time to Seal (hr)
C	50	425	555	4.4	0.08
D	60	876	637	3.2	0.09

Table 10 – LPM Blend for High-Mud-Weight Invert-Emulsion Fluid Optimized for 800-Micron Fracture

LPM	Concentration (lb/bbl)			
	Special Grind Coarse Carbonate	Medium/Coarse Carbonate	Fine Carbonate	Graphite/Industrial Carbon Blend
E	10.2	11.5	14.7	3.5

Table 11 – Fracture Performance of High-Mud-Weight Invert-Emulsion Fluid

LPM	Conc. (lb/bbl)	Mud Press. (psig)	Max Width (µm)	Conduction (ml)	Time to Seal (hr)
E	40	900	742	4.7	0.09
F	77.5	949	654	3.6	0.09

Table 12 – LPM Blends Optimized for Field Application

LPM	Particle Size (µm)			LPM Concentration (lb/bbl)	
	d_{10}	d_{50}	d_{90}	Blend G (650-µm fracture)	Blend H (415-µm fracture)
Graphitic Material	25	133	779	20.5	7
Fine Carbonate	0.72	9.65	20.4	3.5	17.5
Fine/Medium Carbonate	2	40.9	164	16	17.5

Table 13 – Fracture Performance Data for Field Application

LPM	Conc. (lb/bbl)	Mud Press. (psig)	Max Width (µm)	Conduction (mL)	Time to Seal (hr)
G	40	685	650	3.5	0.28
H	42	491	555	14.9	0.61

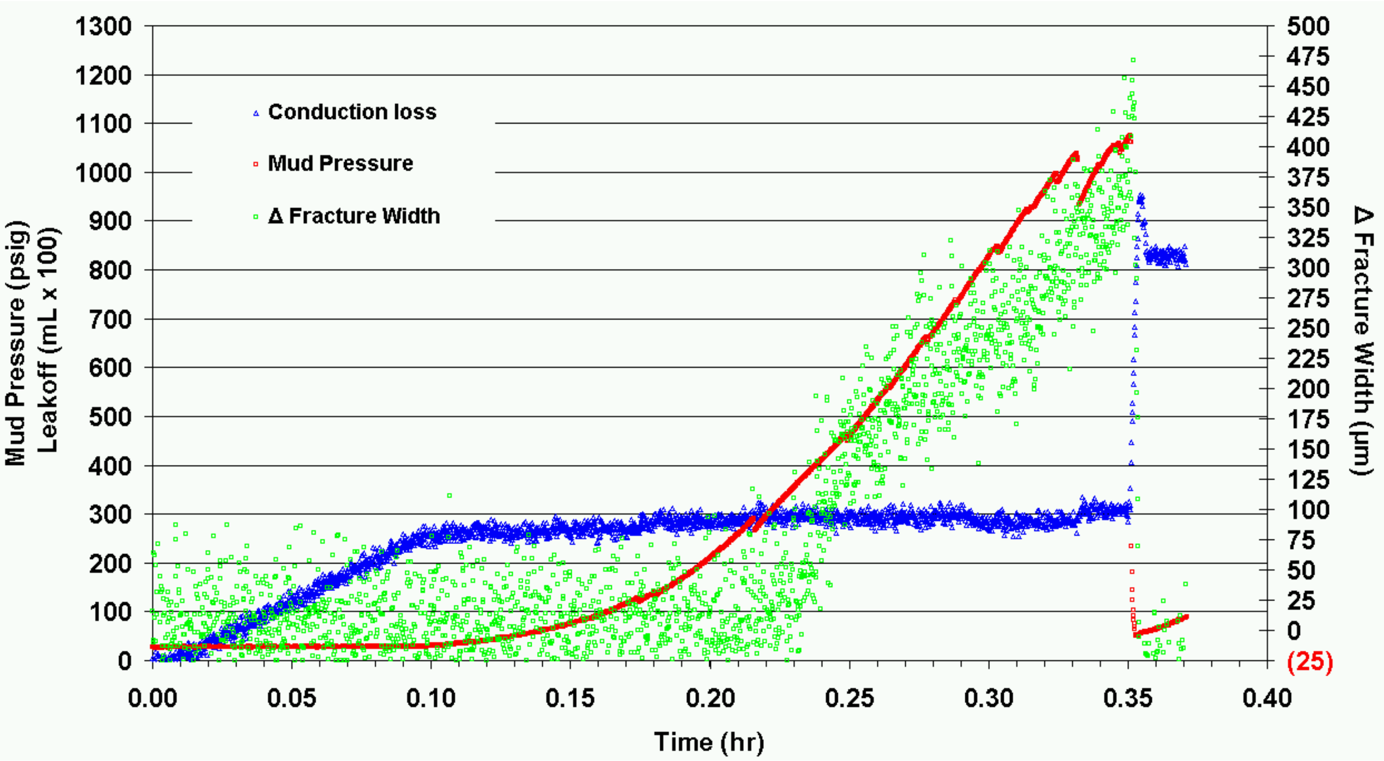

Fig. 1 – Fracture performance data for an invert-emulsion fluid containing 20 lb/bbl of optimized LPM.

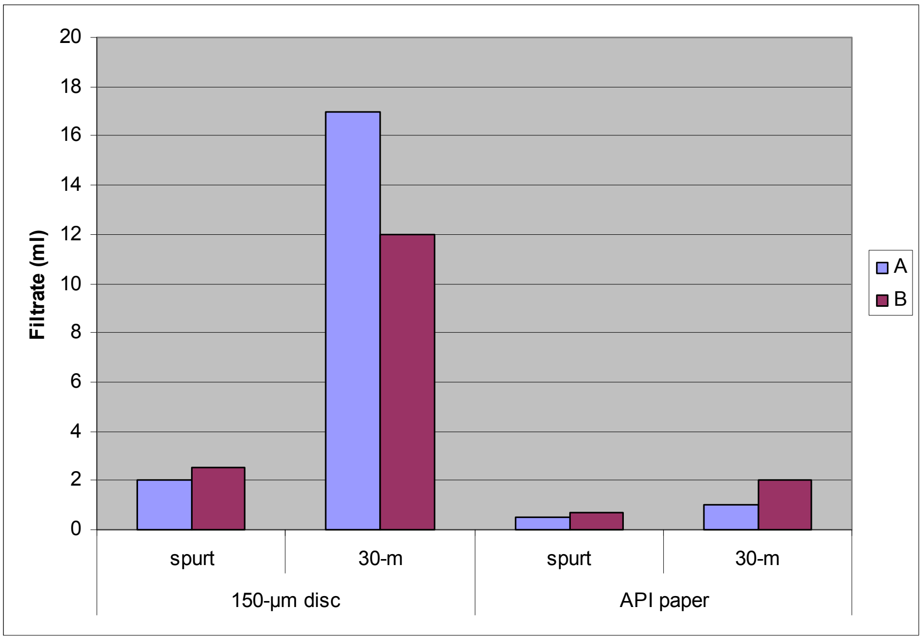

Fig. 2 – HTHP fluid loss for water-based fluid containing LPM blends A and B at 250°F and 500 psi.

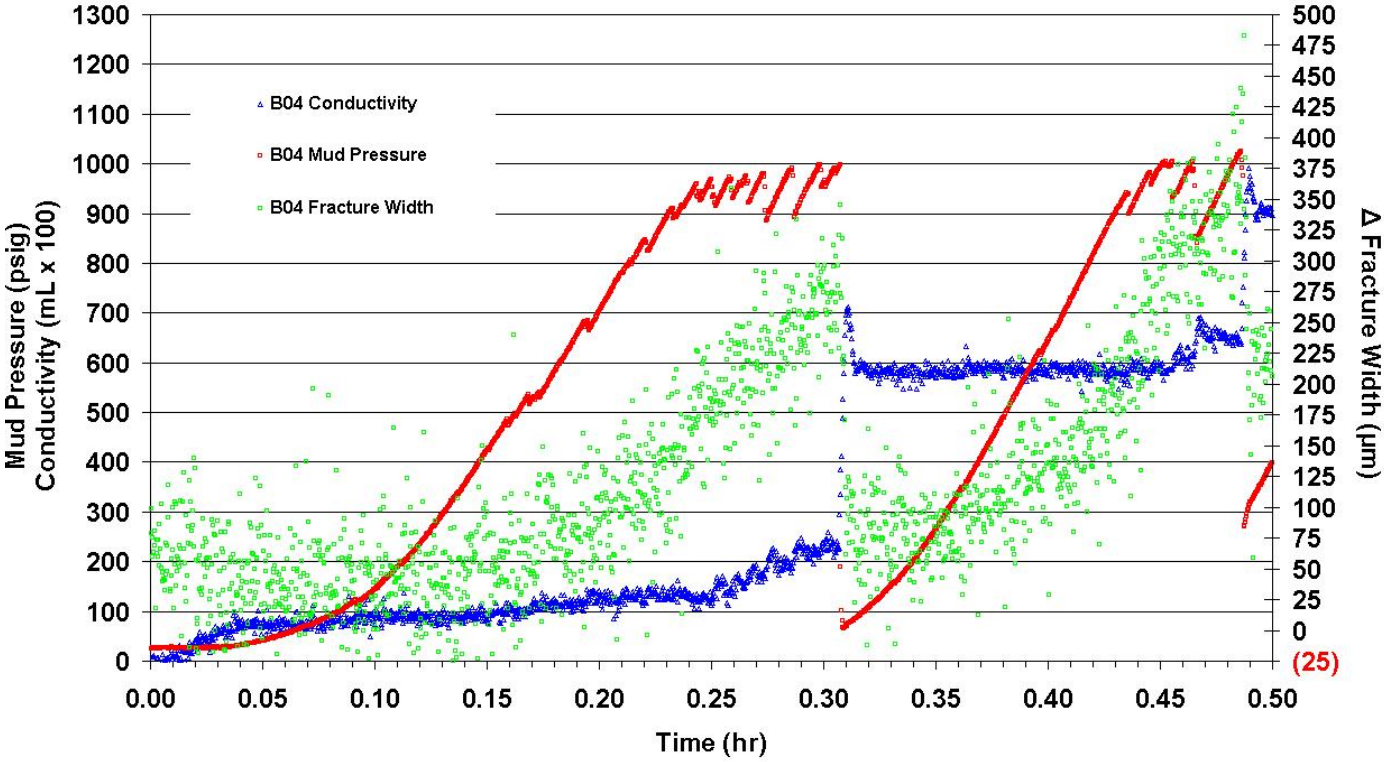

Fig. 3 – Fracture performance data for water-based fluid containing LPM blend B.

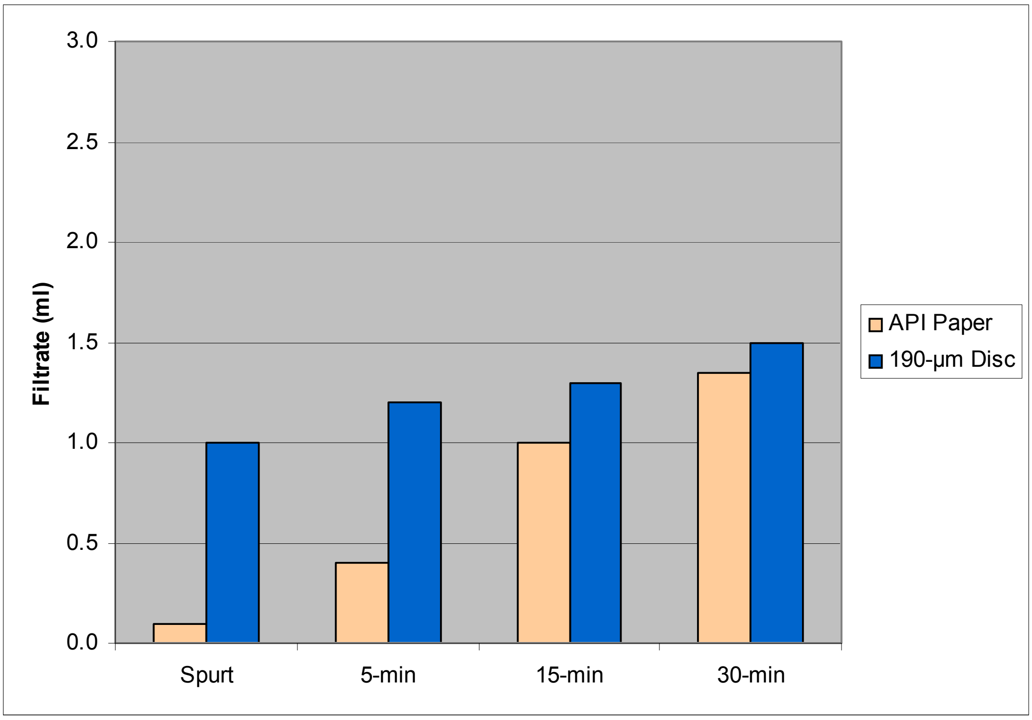

Fig. 4 – HTHP fluid loss of the invert-emulsion fluid containing LPM blend Cat 250°F and 500 psi.

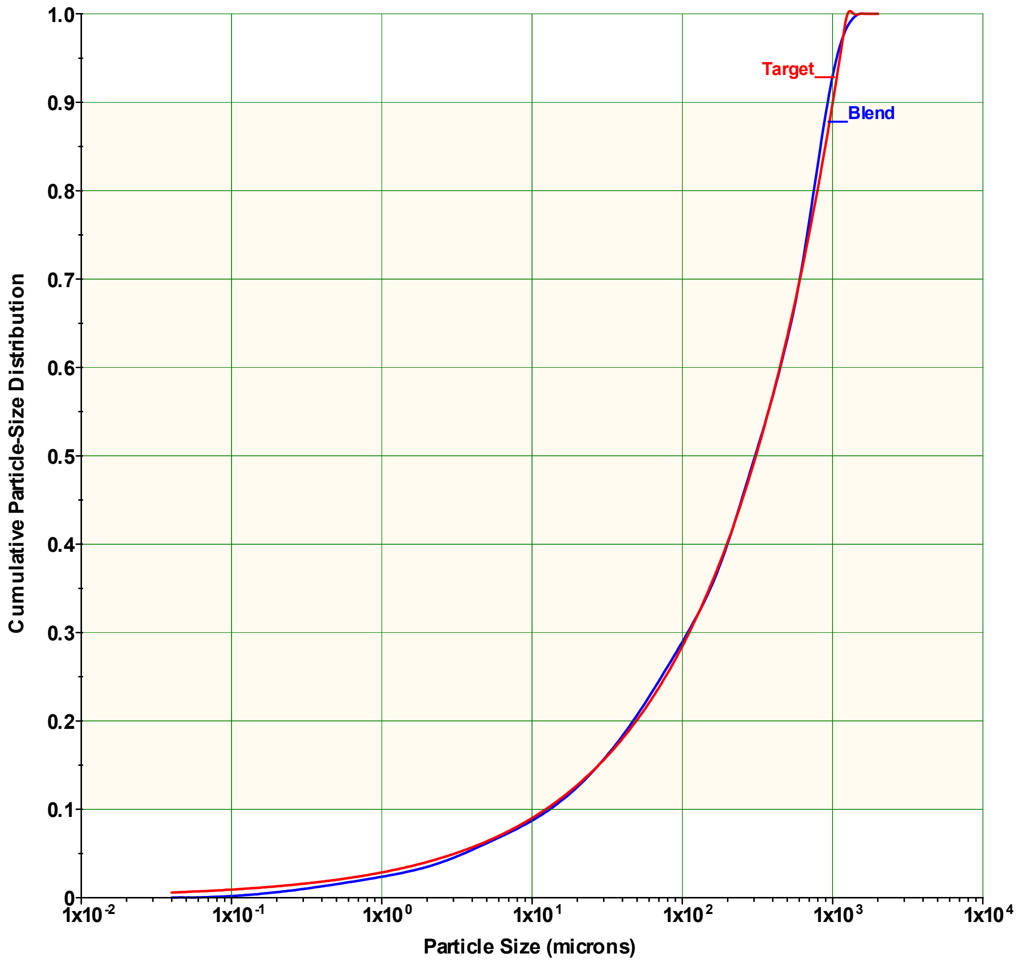

Fig. 5 – Particle size distribution for the LPM blend designed to plug and seal 700 - 800 micron fractures (components given in Table 9).

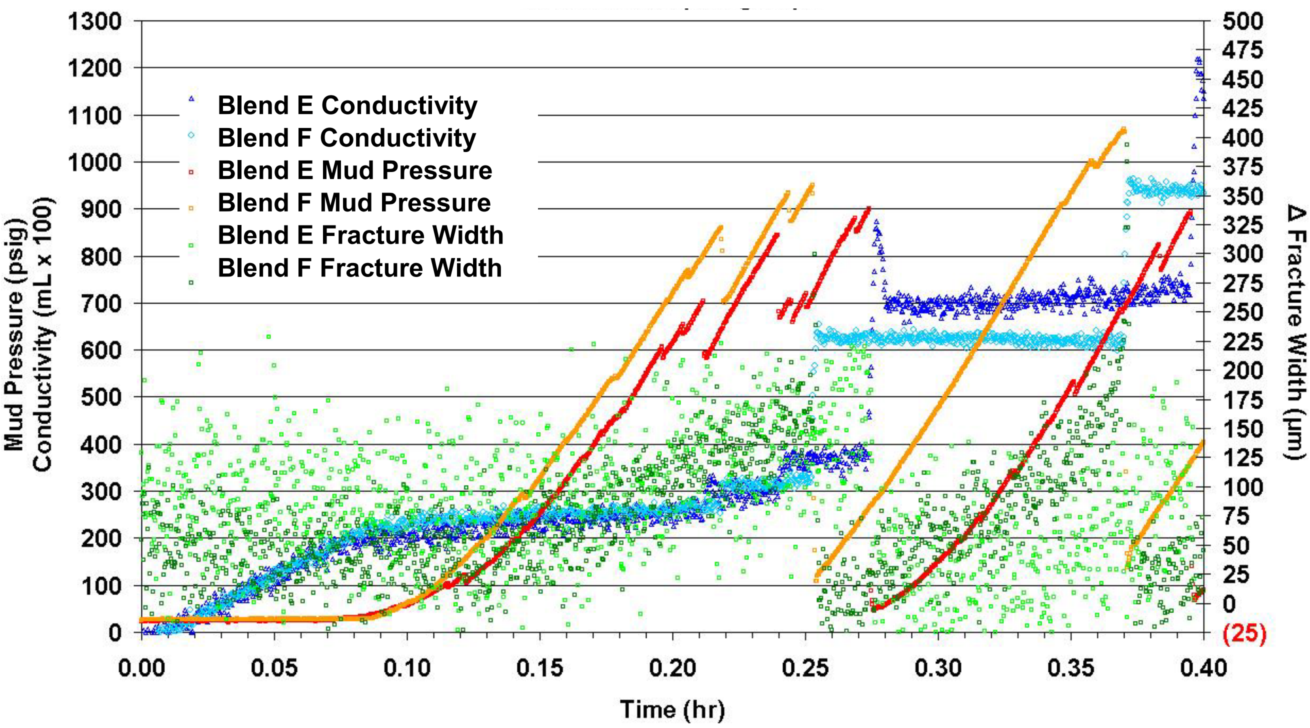

Fig. 6 – Fracture performance for the LPM-laden 18.3-lb/gal invert fluid.