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Case Histories Show Wellbore Strengthening as a Cost-Effective Option for Drilling with Narrow Mud Weight Windows

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Abstract

Drilling is significantly more challenging when a narrow mud weight window is encountered. Failure to stay inside this narrow window may result in significant problems such as lost circulation, hole collapse, well kicks and stuck pipe. Several methods have been developed in recent years to assist drillers in coping with these potential problems. More recently, wellbore strengthening techniques have shown promise to widen the mud weight window in some cases.

Recent studies[1-5] and field practices[6-8] indicate that a weak formation can be strengthened to withstand a high wellbore pressure that exceeds the formation fracturing pressure. This goal has been achieved repeatedly by customizing particulate-treated drilling fluids based on formation mechanical properties as well as the stress field. This proven, cost-effective approach is sometimes referred to as stress cage technology.

This paper reviews the latest results on the mechanism study and general design procedures, followed by several representative case histories selected from several stress cage jobs to demonstrate how the technology has been successfully applied in the field.

Introduction

Particulate lost circulation materials (LCM) have been added to drilling fluids to mitigate lost circulation for years.[9] Although this technology appears to be fairly simple, it has been very controversial. Some operators don't see consistent results with this method and subsequently they are reluctant to use these particulates while drilling. However, others constantly demand this "sealing while drilling" operation.

In recent years, a method that may be used to design a particulate LCM formulation for a defined increase in pressure containment for a wellbore was introduced.[1,6] Though the method may still have weaknesses, and it may still need further improvement[10], the great benefit this new method demonstrates in the field and the high potential of solving the problem of narrow mud weight windows has put it in the spot-light in the drilling industry in recent years. This wellbore strengthening method is sometimes referred to as building a "stress cage".

Though the use of the concept of stress caging in this fashion was introduced recently, a number of studies[2-5,11] have been done to understand the key factors for improving its application. The initial study was criticized for not considering fracture stability.[10] A series of studies[2-5] was conducted with a numerical simulator that considered fracture stability. Results from these studies directly support the stress cage concept and provide a refined understanding of the technology.

Now the stress cage method has been adopted and often used for treating potential lost circulation in the field. After examining many jobs done in the field, we believe it is useful to present and discuss some typical applications.

Review on Mechanism Study

In order to consider fracture stability and stress anisotropy, a numerical method was adopted. With the method, numerous calculations were done to model the strengthening situation to understand 1) whether wellbore strengthening by building a stress cage is a sound method according to rock mechanics theories; 2) the essentials to maintain the strengthening effect; and 3) the factors that will influence engineering design in the field applications.

Studies[2-5] were performed based on a fractured wellbore configuration for a vertical well with the fracture center line in the maximum horizontal stress (S_H) direction penetrating the wellbore center. The wellbore has a radius of r_w and the fracture length indicated in **Figure 1** is L_f. The pressure in the wellbore is P_w and pressure in the fracture is P_f. The tangential stress along the wellbore wall of the first quadrant of the wellbore was studied using a numerical simulator.

Figure 2 shows simulation results of tangential stresses for a fractured wellbore when sealing of the fracture at the fracture mouth is implemented and the fracture is stable. The Y-axis shows the magnitude of the tangential stress along the wellbore wall and the X-axis shows the locations of the tangential stresses along the wellbore wall denoted by the angles from the center line of the fracture. **Figure 2** shows that the tangential stress of a wellbore can be increased when the fracture is stable, even though there is no fracture propping by a solid material. The fracture pressure inside the stable fracture controls the fracture width and the increase in tangential stress.

Figure 3 shows the simulation results of tangential stresses for a fractured wellbore when propping of the fracture at the fracture mouth is implemented and the fracture is stable. Similar to **Figure 2**, the Y-axis shows the magnitude of the tangential stress along the wellbore wall and the X-axis shows the locations of the tangential stresses along the wellbore wall denoted by the angles from the center line of the fracture.

If the fracture is propped by a solid, the propping effect provides an increase in tangential stress along the wellbore. This effect is clearly shown in **Figure 3.** Further studies indicate that low fracture pressure still has to be maintained for fracture stability and that propping fractures can increase Wellbore Pressure Containment (WPC) to a much higher level than sealing.

The series of studies presented in references 2-5 not only indicates that the stress cage treatment has a sound rock mechanics basis, but also reveals how various parameters such as Young's Modulus, Poisson's Ratio, stress anisotropy, fracture length, fracture pressure, wellbore pressure, wellbore radius, and crack opening displacement (COD) will all affect the increase of the tangential stress and the stability of the fracture. Please refer to the literature[2-5] for more details.

The studies in references 2-5 indicate that under certain conditions, a wellbore with fractures may have a higher tangential stress, which is a requirement for higher pressure containment, and the fractures can be maintained stable. The mechanisms underlying the stress cage can be summarized as the following:

1. Sealing the fractures
2. Propping the fractures

Details in references 2-5 indicate that sealing the fractures is necessary for maintaining a low fracture pressure on the fracture tip side for fracture stability and propping the fractures provides an efficient increase in tangential stresses. Sealing alone can provide a very large strengthening effect. However, because of fracture instability, propping the fracture without sealing is neither sufficient nor recommended.

General Application Procedure

The application of a stress cage treatment generally falls into the following procedure:

1. Data collection
2. Fracture modeling
3. Mud formulation
4. Field implementation

Data collection is essential for the engineering design. Based on the complexity of the wellbore and stress field, the required data set can be quite detailed[12]. The simplest case occurs when a vertical well is drilled in a uniform horizontal stress field. The data required are basically the following:

- Young's Modulus (E)
- Poisson's Ratio (ν)
- Hole size
- Minimum Horizontal Stress (S_h)
- Needed Wellbore Pressure Containment (WPC)

Young's Modulus and Poisson's Ratio are basic rock mechanical properties to determine rock elastic deformation under stresses and pressure. These data can be obtained from lab tests. However, more often they are derived from log interpretation with the following equations:

$$E = \frac{\rho v_s^2 \times \left[3\left(\frac{v_p}{v_s}\right)^2 - 4\right]}{\left(\frac{v_p}{v_s}\right)^2 - 1} \quad \text{and } \nu = \frac{\left(\frac{v_p}{v_s}\right)^2 - 2}{2\left[\left(\frac{v_p}{v_s}\right)^2 - 1\right]}$$

where,

ν_p – compressional velocity
ν_s – shear velocity
ρ - density

These equations yield dynamic values that are normally higher than the static values needed for determining fracture width. The static values of these elastic parameters may be obtained through empirical correlations or from lab tests.

The minimum horizontal stress may be calculated from the vertical stress and Poisson's ratio. The vertical stress can be calculated through integrating density log data. A better value of the minimum horizontal stress may also be obtained by analyzing leak-off tests, lost circulation data, etc.

The needed WPC comes from the wellbore pressure predicted/experienced for drilling, running casing, or cementing, etc.—whichever is the highest. These pressure containment values can be obtained by drilling fluid and cementing computer simulations that are routinely done in the drilling industry.

With the collected data, a quality control step is needed to make sure that the data are of acceptable quality, interpreted values have no conflicts with the general knowledge for the area, and input parameters are within an acceptable and reasonable range.

Then the data will be input into a computer program to model the fracture size. The computer program, built based on the linear elastic theory and within the constraints of the model, will predict a fracture width. With the fracture width defined, the program can then be further used to design the particulate formulations that provide an efficient particle size distribution to seal and prop the fracture. Theoretically, there may be a large number of solutions possible by mixing particulate materials. With practical constraints such as availability of the particulate materials and logistics, only a smaller number of solutions will be generated by the computer program. Engineers may then choose the one that best fits their requirements.

The formulations can be tested with ceramic discs and slotted discs on Permeability Plugging Apparatus (PPA) (**Figure 4**) for verification. The ceramic discs are used to check permeability plugging while the slotted discs are used to check fracture plugging. The discs are shown in **Figure 5**.

Adding particulates to the drilling fluids tends to increase the viscosity. This effect should be quantified to aid in equivalent circulating density (ECD) prediction. Since the particulates interfere in the measurement of the drilling fluid viscosity, an engineering algorithm has been implemented for determining the viscosity in the presence of particulates.

Using the input of particulate types and concentrations, base mud viscosity etc., the program can predict the new viscosity with a very good accuracy (**Figure 6**). The blue line shows the lab data for the particulate treated mud and the purple line shows the predicted data by the program for a 12.0 ppg SBM treated with 20 ppb of a ground marble, 16 ppb of a resilient graphitic carbon (RGC) and 10 ppb of a fiber. In this example, all of the selected material particles were small enough so as to not interfere with the subsequent measurement of the rheology by a standard rotational bob viscometer.

In the field, a designed particulate formulation has to be maintained. Regular measurement of the particulate size distribution may be needed for a long drilling interval. Addition of coarse particulates is needed especially when shale shakers are not by-passed and part of the particulates is separated out of the mud system while drilling. For quality control of the process, it would be even better if the plugging effect can be regularly checked with a PPA as done in the lab at the mud formulating phase.

Case Histories

Narrow mud weight window scenarios represent a challenging environment to well designers. A narrow mud weight window forms when a high collapse pressure or formation pressure zone exists in the same drilling interval with a weak formation. This is usually seen in drilling depleted formations. Stress cage applications are especially suitable for meeting this kind of challenge. However, the application of the wellbore strengthening technology may be different when the sequence of the high pressure zone and the weak zone varies.

General Considerations

When the weak zone is at the top, the mud used to drill through it may be particulate free as long as the ECD is maintained below the fracture gradient. After drilling through the weak zone, a method should be used to determine how weak this zone really is. Due to the uncertainty of depletion, some formations may not be as weak as predicted. If this is the case, wellbore strengthening is not needed.

The methods used include a pressure test such as Formation Integrity Test (FIT) or Leak-Off Test (LOT). Sometimes operators do not want to test the wellbore due to instability concerns. In this case, an indirect method, though it might not be as reliable as the pressure test, can be used. This indirect method may use a formation tester while drilling to determine the real formation pressure of the depleted formation right after it has been penetrated. With the pore pressure obtained, geomechanical calculations may be performed to determine if the formation is as weak as predicted. Then a decision can be made for using or not using the wellbore strengthening method. This was done with one operator, and it was determined that wellbore strengthening was not required.

After the weak zone has been penetrated, the mud system may be treated with designed particulate formulation for increasing the mud weight necessary for drilling the higher pressure deeper zones.

When the weak zone is on the top and wellbore strengthening is deemed necessary, the designed pill can be spotted and the stress cage can be “set” by pressurizing the wellbore to a designed pressure level. After the stress cage is successfully set, the pill can be swapped out with normal mud. Then a pressure test can be performed to help ensure that the strengthening effect has been achieved. Mud with a higher mud weight can be used for the lower interval drilling as long as ECD is controlled below the pressure test level. Though there are risks associated with this technique, it has been done successfully in the field.

When the weak zone is below a high pore/collapse pressure zone, the mud weight has to be higher than the low fracture strength when penetrating this weak formation. In this case, the mud has to be treated with the designed particulates for strengthening while drilling. However, after penetrating the specific weak zone, if no additional weak zones are anticipated, it is still possible to swap out the particulate treated mud with particulate free mud to continue drilling.

Other applications of wellbore strengthening may include squeezing a casing shoe with a strengthening pill, especially when a casing shoe is set in a permeable sandstone formation. When the shoe test doesn’t meet the requirement, this method can help to achieve the desired FIT or LOT.

The cost of discarded coarse particulate LCM together with cuttings by shale shakers can be calculated by the mesh size of the selected shale shakers and circulation rates. The addition of the coarse particulate LCM can be designed also based on these data. New technologies for recovering the particulate LCM are currently being developed.

Maintaining a high concentration of abrasive particulates in the active mud system may cause erosion of some hardware such as downhole mud motors, mud pump liners, etc. Considering this factor is important when selecting the particulate materials.

Case 1. Narrow mud weight window formed by high collapse pressure and low fracture pressure in the same drilling interval

Typically a higher pore pressure shale formation lies above a depleted reservoir formation. In this case it is necessary to drill into the formation with a wellbore pressure that is high enough to stabilize the shale. However, sometimes the reservoir formations are so depleted that the required pressure to stabilize the shale will fracture the reservoir formations.

When this happens, not only will mud loss occur, but hole collapse, stuck pipe and further loss of the bottomhole assembly due to the sudden drop of wellbore pressure with the decrease of the fluid level may take place. Curing such mud losses can be very difficult. Loss of the hole may happen and a sidetrack may have to be implemented. However, without a good solution, the same may circumstances may happen again.

A drilling engineer may consider the following solutions:

1. Drilling and setting the casing as close to the depleted formation as possible, then using lower mud weights to drill the reservoir section;
2. Using expandable casing to isolate the high pressure shale;
3. Setting a liner to isolate the shale formation;
4. Using casing drilling to cope with the losses and potential hole collapse.

However, all of these options have to deal with a high risk for either hole collapse or mud losses. In addition, there is potential high cost due to logistics, hardware and operational time and risk. With stress cage, or wellbore strengthening, the picture is different. Because the technology can strengthen the wellbore while drilling, it provides a means to help prevent lost circulation while drilling. If properly implemented, the drilling operation may not be different than normally seen.

Well A in the North Sea area was facing exactly the problem described above. The reservoir pressure gradient was predicted to be 8.8 ppg due to depletion. The depleted reservoir formation had a predicted fracture gradient of 14.8 ppg, however, the required wellbore pressure for stabilizing the cap rock shale was over 20 ppg. Engineering modeling based on the parameters shown in **Table 1** resulted in an estimated fracture width of about 1500 microns due to the large pressure overbalance.

Based on the modeling, particulate formulations were designed and tested. One of the selected formulations is shown in **Table 2**.

The particulate formulation comprised resilient graphitic carbon (RGC) and ground marble calcium carbonate particulates. The particulate concentrations and D50 are shown in **Table 2**. The particulate size distribution (PSD) is shown in **Figure 7**.

Due to the needed high wellbore pressure for stabilizing the cap rock, the depleted formation was drilled with the required high mud weight. Despite the huge overbalance, the well was drilled successfully with the designed formulation without mud losses!

Case 2. Narrow mud weight window formed by high and low formation pressures in different layers of the same drilling interval

Another example was **Well B** drilled in Europe by a different operator. This well had a highly depleted high permeability sand layer in the reservoir section due to production from a nearby well. The depletion resulted in a formation fracture gradient below the ECD for drilling and considerably below the ECD for cementing. The high mud weight was needed for balancing the formation pressure from other less permeable layers. The risk of heavy losses called for this wellbore strengthening application.

The formation properties were obtained from geophysicists and ECD values were obtained from simulations of drilling and cementing operations. The conditions were modeled with a specially coded computer software program for wellbore strengthening and a particulate formulation was customized based on the inputs. The formulation is shown in **Figure 8**, which also shows the PSD for each particulate component. The d10, d50 and d90 of the composite mixture are also shown. A cumulative curve for the complete composition is also available. The particulate volume percentage is the Y-axis on the left. This was the formulation used to drill the 4 7/8” reservoir section. The formulation was maintained during drilling with additions of new materials based on PSD analysis.

The drilling went smoothly with only one occurrence of mud losses. This was easily cured by spotting a 2.5-m^3 LCM pill with a higher concentration of the coarse materials. No further losses were observed even during cementing.

Case 3. Engineering design process enables better engineering decisions

The engineering design can also forecast the need for wellbore strengthening.

Another operator planned to drill **Well C** with depleted formations. The reservoir has depleted over the years from over 17.5 ppg to about 6.5 ppg as shown in **Figure 9**. Wellbore stability studies indicated that the shale collapse pressure is 17.0 ppg. However, the sand fracture pressure was predicted to be between 13.2 and 14.5 ppg.

With the request for wellbore strengthening, rock mechanical properties were collected and modeling was done with the computer program. It was estimated that the fracture width was about 4000~5000 microns with conservative parameters. Even with a less conservative approach, the fracture width was still about 2500 microns. Due to the lack of appropriate particulate materials and the potential complication of the operation, the wellbore strengthening approach was deemed as not suitable. This allowed the operator to focus on other options to drilling the well and prevented him from making an unsuccessful drilling attempt.

Conclusions

Numerical studies and field applications both have shown that wellbore strengthening (stress cage) is a reliable approach for improving wellbore pressure containment. Implementing stress cage treatments in the field is not difficult; however it requires specialized engineering planning tools and materials.

Numerical studies on wellbores with stable fractures show that the wellbore strengthening may be achieved by sealing the fractures. However, propping the fractures can bring the increase in WPC to an even higher level.

The application of wellbore strengthening treatments generally fall into the steps of data collection, fracture modeling, mud formulation, and field implementation.

Quality control may be built into the engineering process to help ensure the success of the application.

Case histories show that wellbore strengthening treatments can solve narrow mud weight window problems very efficiently.

Acknowledgments

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Nomenclature

E	= Young's Modulus, psi
L_f	= Fracture length, inch
P_f	= Pressure inside a fracture, psi
P_o	= Pore pressure, psi
P_w	= Wellbore pressure, psi
r_w	= Wellbore radius, inch
S_H	= Total maximum horizontal stress, psi
S_h	= Total minimum horizontal stress, psi
S_v	= Total vertical stress, psi
ν	= Poisson's ratio
ν_p	= Compressional velocity, ft/s
ν_s	= Shear velocity, ft/s
θ	= Angle from the fracture center line, degree
ρ	= Density, slug/ft^3
BEA	= Boundary Element Analysis
COD	= Crack Opening Displacement
ECD	= Equivalent Circulating Density
EMW	= Equivalent Mud Weight
FIT	= Formation Integrity Test
GOM	= Gulf of Mexico
LCM	= Lost Circulation Materials
LOT	= Leak-Off Test
PPA	= Permeability Plugging Apparatus
PR	= Poisson's Ratio
PSD	= Particulate Size Distribution
RGC	= Resilient Graphitic Carbon
WPC	= Wellbore Pressure Containment

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Tables

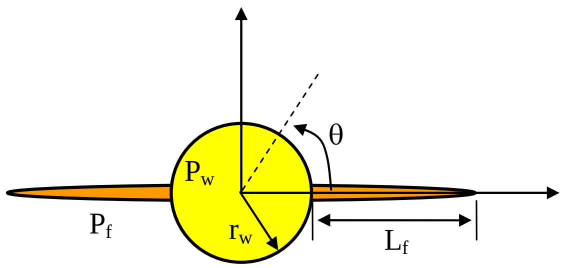
Table 1 Input Parameters for Drilling Well A

Depth, ft		Stress					E		PR
			bar	g/cc	psi	ppg	bar	psi	
17095	Cap Rock - Shale	S_h	1237	2.42	17937	20.2	120	1,740,000	0.3
		S_H	1427	2.79	20692	23.3			
		S_v	1295	2.54	18778	21.1			
		P_o							
17135	Depleted Reservoir - Sandstone	S_h	907	1.77	13152	14.8	120	1,740,000	0.2
		S_H	1107	2.16	16052	18.0			
		S_v	1218	2.38	17661	19.8			
		P_o			7803	8.8			

Table 2 Designed Particulate Formulation for Well A

Materials	Amount	D50, microns
Base mud (17.1 ppg), bbl	1.0	(Barite + clay)
RGC-1, lb	40	1180
Ground Marble 1, lb	8	600
RGC-2, lb	8	425
Ground Marble 2, lb	8	325
RGC-3, lb	8	150
RGC-4, lb	8	80

Figures



Angle from the fracture center line = θ
Wellbore radius = r_w
Fracture length = L_f
Wellbore pressure = P_w
Fracture pressure = P_f

Figure 1 Defining the Fractured Wellbore

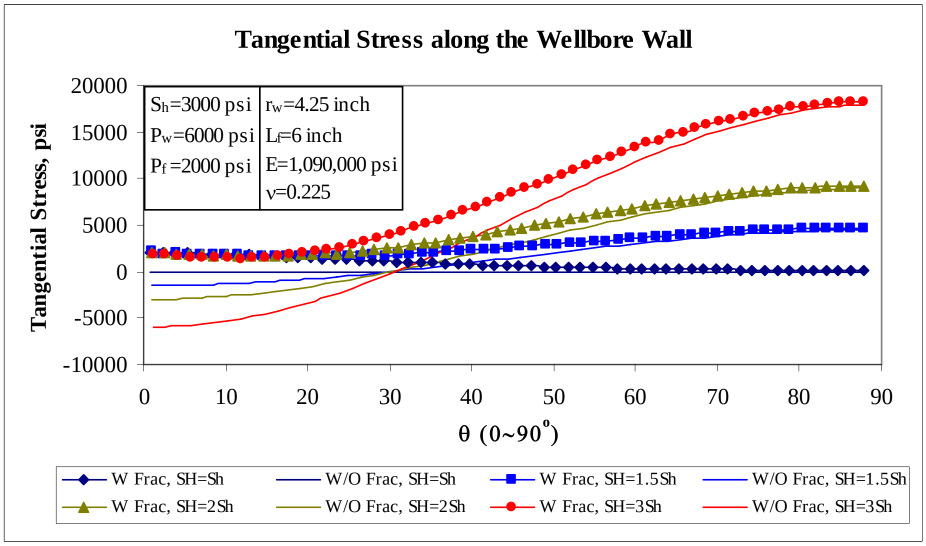


Figure 2 Tangential Stress at the Wellbore Wall

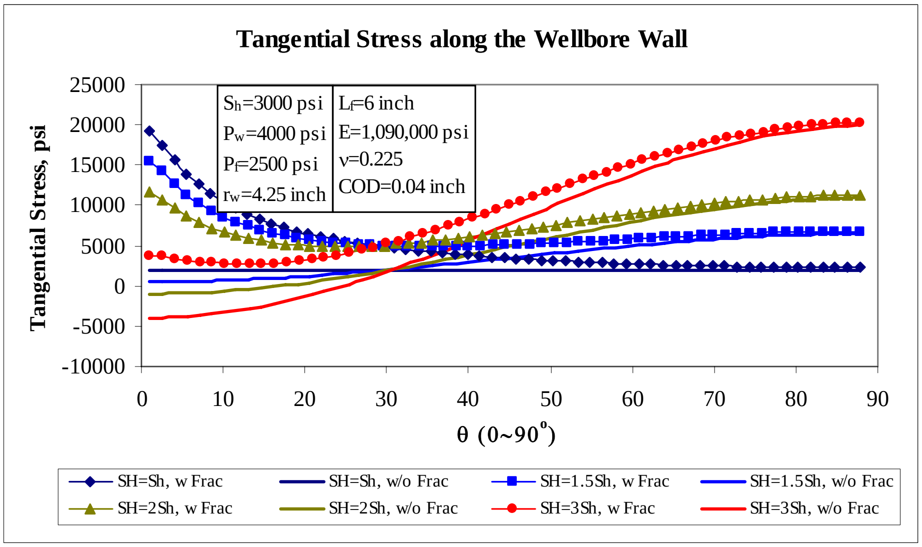


Figure 3 Tangential Stress Improved by Propping the Fracture

Figure 4 Permeability Plugging Apparatus (PPA)

Figure 5 Discs Used for Testing the Particulate Formulations

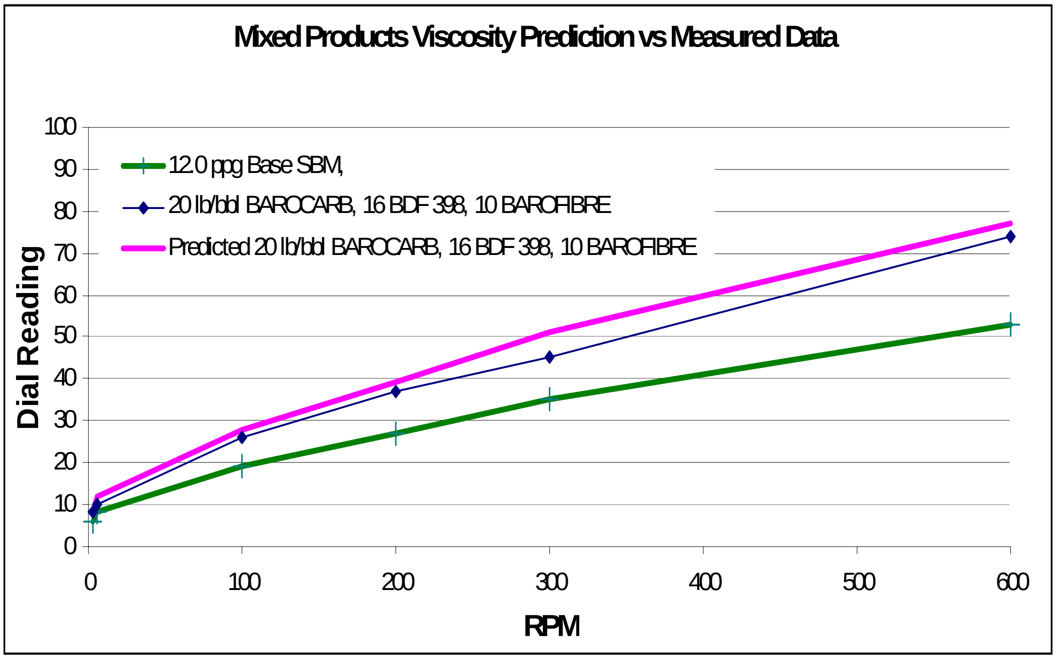


Figure 6 Comparison of Measured Viscosity and Predicted Viscosity for a Particulate Formulation

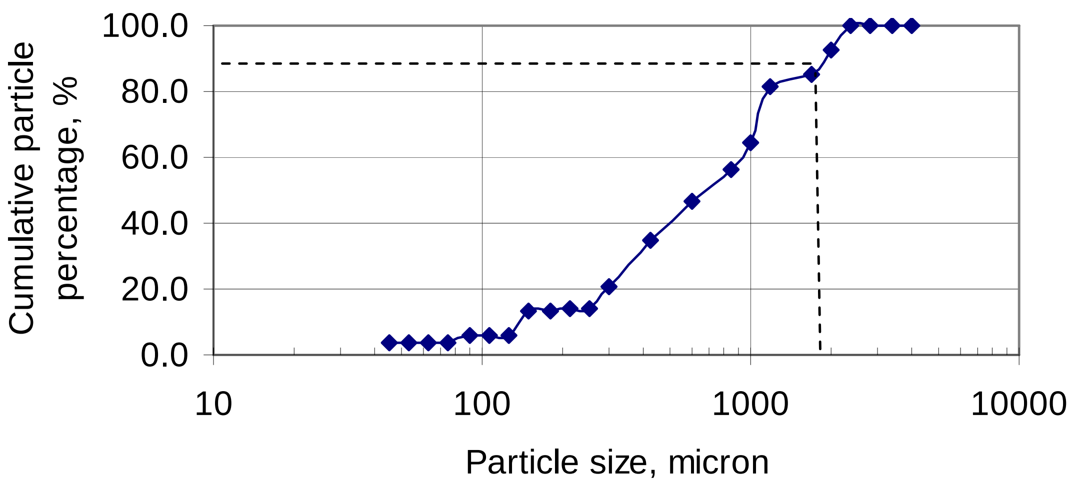


Figure 7 Particulate Size Distribution of the Designed Formulation

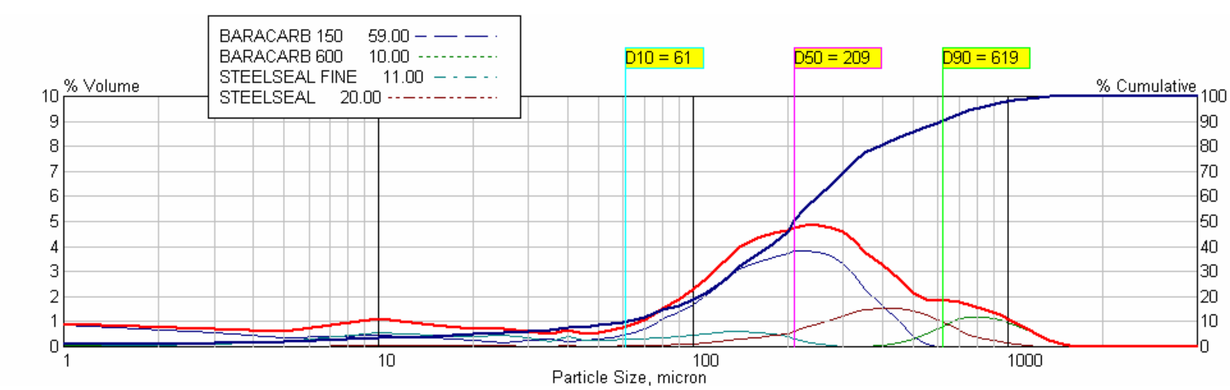


Figure 8 Particulate Formulation for Well B

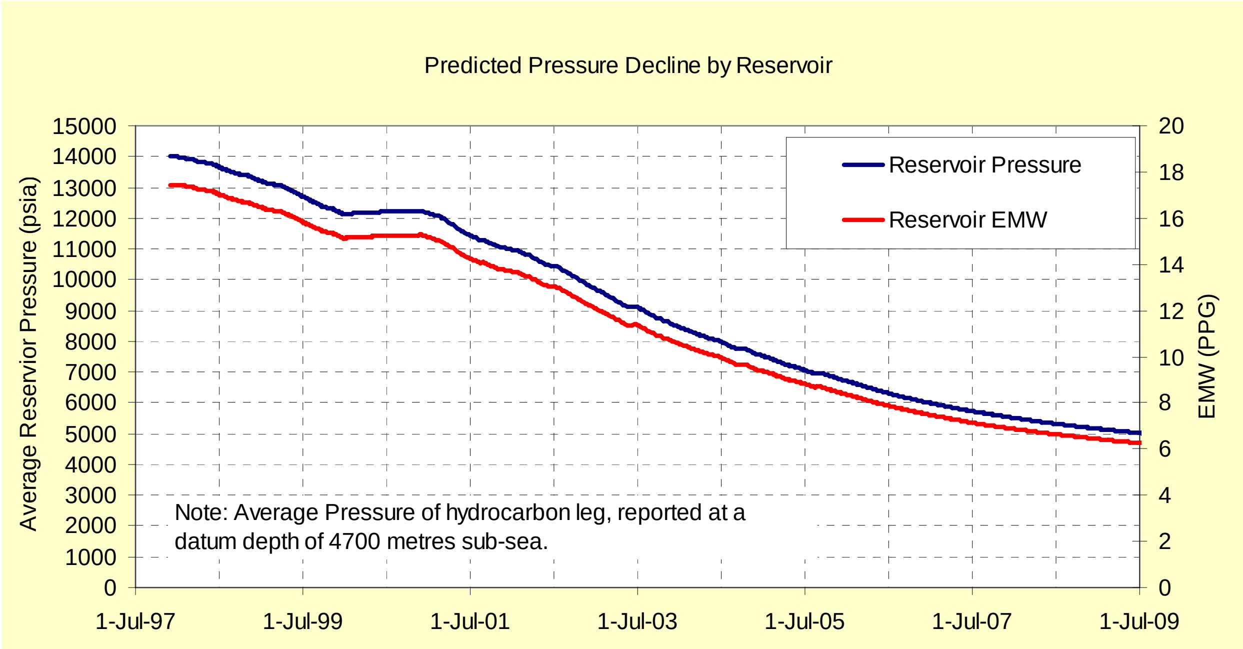


Figure 9 Predicted Reservoir Pressure Decline