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Formate Fluid QRA

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EXECUTIVE SUMMARY

IDM Engineering has conducted an independent investigative study to determine the relative advantage that could be gained, during the completion of a typical drilling programme, by using either Formate Fluids (FBF), Oil Based Mud (OBM) or Water Based Mud (WBM).

The study was commissioned by Peer Group International Ltd on behalf of Cabot Speciality Fluids Ltd.

Aim of Study

The aim of the study was to quantify, through a Quantitative Risk Assessment (QRA) approach, the relative benefits, if any, of using FBF as a drilling fluid in preference to the widely used OBM and WBM.

The study was limited to consider four generic commonly used well types in combination with each of the three drilling fluids mentioned above. In this way general guidance could be provided for use across the drilling industry as a whole.

The well types examined in the study were as follows:

- Through Tube Rotary Drilling (TTRD) from an existing well
- High Pressure / High Temperature (HPHT) well
- 90 Degree Producer well
- 60 Degree Extended Reach Drilling (ERD) well

Modelling Methods

Risk modelling techniques were employed and mathematical models then built to represent 75 issues that were considered most relevant to the advantages and disadvantages that could be gained by using one specific drilling fluid type over another.

For the purpose of the modelling, environmental issues were excluded as they formed part of the scope of another study.

Monte Carlo simulation techniques were employed to generate data from which S curves were derived to display the potential times taken to complete a generic drilling programme for each of the drilling fluid and well type combinations. Histograms were also produced for the additional costs that could be expected from using one fluid rather than another.

Results

Significant improvements in drilling programme times were demonstrated by the models by using FBF. A substantial part of the improvements were caused by improved drilling rates of penetration (ROP).

Over the four well types, OBM generally took between 20% and 38% longer than FBF to complete, and for the corresponding WBM cases, between 26% and 70%. Section 5 Results, details the Drilling Programme times for each of the well and fluid type combinations.

In each of the four well types drilling times were improved using OBM rather than WBM.

The cost advantages (excluding base fluid costs) were maximised using FBF with OBM significantly disadvantaged due to drilling cuttings processing costs.

Over the four well types the average additional costs associated with each fluid, excluding base cost of the fluids themselves, were: £0.58M for FBF, 0.82M for WBM and £2.40M for OBM.

Costs in the model were also separated into formation damage and non-formation damage costs. The FBF was not considered to cause formation damage.

Conclusions

Although FBF has been developed for some time, it is still a relatively new product in the drilling fluids market. As such there is not extensive data available concerning its performance. Thus the models have had to rely, in part, on engineering experience and empirical data from independent literature to help populate them.

As data becomes more widely available, better more accurate models could be used to further demonstrate the advantages of FBF over OBM and WBM. This may be particularly useful in the case of specific well designs in the development of budgets.

In consideration of the many issues that were employed to examine the relative benefits of the fluid, the models clearly show both a significant time and cost improvement when FBF was employed.

It should also be noted that the number of issues under consideration in the models, that were found to be either negligible or of little significance, was substantially greater for FBF than for either of the other fluids considered. This could provide the user with secondary benefits, which were not explicitly quantified in this study.

1 INTRODUCTION

1.1 Background Information

This study was commissioned by Peer Group International on behalf of Cabot Specialty Fluids to assess the capability of Cabot's FBF against the more traditional drilling fluids, namely OBM and WBM.

The main assumption of this study considers that the reservoir geology and associated tests to establish the reservoir inventory is suitable to be exploited and that a drilling programme has been devised accordingly.

1.2 Drilling Fluids

⁽²⁾ & ⁽³⁾ The application of drilling fluids has become more diverse as the technology has advanced. The main function of the drilling fluid for rotary drilling operations is to:

- Carry the cuttings from the bit to the surface for separation and cleaning.
- Lubricate, cool and clean the bit.
- Prevent inflow of fluids.
- Prevent formation damage.

Two out of the three drilling fluids considered by this study are commonplace in the industry, namely WBM and OBM. Formate based fluids are relatively new.

1.3 General Properties

⁽²⁾ & ⁽³⁾ Drilling fluids are classified according to their bases:

Water Based Muds

Solid particles are suspended in water or brine.

Oil Based Muds

Solid particles are suspended in an oil / water emulsion. Water or brine is emulsified in the oil.

Formate Fluids

Formates are virtually solids free fluids.

Each of the selected drilling fluids has a variety of strengths and weaknesses depending on application with respect to the well types the fluids may be employed in. This is investigated in this study.

1.4 Scenarios

In order to attain a balanced view of the capabilities of FBF over its competitors the models generated have considered a selection of generic well types.

The following well types were chosen to represent the broad spectrum of well types that exist in the industry.

- TTRD on an existing well
- HPHT well
- 90 Degree Producer
- 60 Degree ERD

12 models were created to take account of all possible configurations of drilling fluid and well type. It is the intention of this study to compare each model at a suitable level in order to get an appreciation of the impact of the various issues surrounding a typical drilling programme. The twelve configurations modelled are detailed in Table 1 below.

Table 1: Model Configurations

Drilling Fluid Type	Well Type			
	TTRD	HPHT	90 Deg Prod	60 Deg ERD
WBM	✓	✓	✓	✓
OBM	✓	✓	✓	✓
FBF	✓	✓	✓	✓

1.5 Drilling Programme

For the purpose of this study a drilling programme will be split into three distinct phases:

- Drilling
- Reservoir completion
- Well testing

A common scale was required to compare each drilling fluid and well type combination. In the drilling operations the most obvious drivers for the drilling programme are time spent and the cost of the programme. The time taken to carry out typical drilling programmes for each type of well was then identified. The figures are quoted in terms of drilling and well completion time for simplicity, with testing incorporated into these figures. Table 2 details the timelines for the different well types.

Table 2: Timelines for typical wells

Well Type	Drilling Phase (Days)		Drilling Programme (Days)
	Drilling	Completing	
TTRD	25	5	30
HPHT	110	10	120
60 Deg ERD	85	5	90
90 Deg Producer	55	5	60

The models consider the additional costs that can be attributed to the use of each fluid type in relation to each other. Thus common costs are not considered. Also, the cost of each fluid for purchase or hire is left out of the study.

The costs associated with a drilling programme are notionally based on the timeline of the drilling programme and can be split into the following sub-headings:

Known costs:

- Hardware hire (equipment and rigs)
- Resource costs
- Planned work

Unknown Costs:

- Delays caused by the environment
- Drilling time taking longer than planned
- Hardware failure
- Downhole problems

1.6 Quantitative Risk Assessment (QRA)

QRA techniques were employed to establish the differences between the various configurations of drilling fluids and well types.

The QRA investigates the significance of known issues with respect to the efficiency of the drilling programme in terms of lost time and additional expenditure.

The outputs from the QRA are presented in two forms; S-Curves for the additional time and stacked histograms for the additional expenditure. This would then show the relative impact of using the different drilling fluids with the different well types.

Firstly, a set of data is created for each of the 4 well types listed, the time for a perfect well is defined according to the associated well design data that can be found in the engineering section. These are trouble free well times and are representative for each well type.

The issues that arise as a result of using each of the 3 mud systems were then defined giving some initial plus items to be analysed such as ROP, cuttings treatment etc. Of the identified issues there were a number that were considered to be negligible in terms of time of cost and were discounted from the model.

The Boston Square was then applied to define the frequency and impact of each of the above items, the distributions of each were entered into the monte carlo simulation and an iterated median point taken from each of the graphical distributions created. This data was then used to define the likely additional time or cost that the relevant item for each well and fluid type may create and finally all the potential time and cost additions were compiled for each well and fluid type to produce a cost / time addition for each fluid and well type. The results are based upon the probabilistic determination that each individual item could occur (defined by the frequency and impact distributions)

2 OBJECTIVES

The objectives of the study are as follows:

- To determine and assess a number of issues which are considered important to the relative advantage that could be gained by using one fluid type rather than another.
- Provide a quantitative comparison between a typical OBM, WBM and the FBF provided by Cabot when used with four commonly used well types: TTRD, 60 Degree ERD, 90 Degree Producer and HPHT.
- Present the QRA findings in a standard format using S-Curves and histograms to compare each drilling fluid together with each well type.

3 SCOPE OF WORK

3.1 Strengths and Weaknesses

- Establish the main criteria to compare each drilling fluid on. Assign levels of importance to each criterion.
- Discuss the strengths and weaknesses with each fluid with respect to the main criteria for comparison detailed above.

3.2 Significance Analysis

- For each drilling fluid and well type configuration determine qualitatively the frequency and impact on the drilling programme of each issue.
- Rank each issue in terms of significance.
- Compare the results between drilling fluids and well types.

3.3 Data Generation

- Based on the significance analysis process, for all the issues categorised as 'low' or 'very high', data would be generated.

3.4 Model Generation

- Map out drilling programme concerning the use of drilling fluid from storage (ready to use) to when the mud is reclaimed and recycled.
- For each well type determine the approximate timeline associated with the key stages of the drilling programme.
- Create a model to represent the key stages at which the drilling fluid is utilised for each well type and drilling fluid type.

3.5 Deliverable

- Generate a table for each of the well types detailing the comparison of each drilling fluid using FBF as a benchmark.
- Show graphically the relative performance of each drilling fluid for each well type to define which is most favourable.
- For each well type and drilling fluid combination, generate an S-Curve for additional time.
- For each well type and drilling fluid combination, generate a stacked histogram for additional cost.

- Summarise for each drilling fluid an S Curve and stacked histogram to indicate the relative performance.

4 METHODOLOGY

4.1 STRENGTHS AND WEAKNESSES

The three drilling fluids under consideration as detailed in the introduction are as follows:

- OBM
- WBM
- FBF

Examining the functionality of a typical drilling fluid, a number of what was considered to be significant issues (80) were identified based on typical events occurring within a drilling programme for the well types defined earlier and the drilling fluid characteristics detailed above.

The associated 'effect' of each of the issues was then determined using the Boston Sq items. uare to ine the effect by defining the impact and frequency of the issue in question for each of the

Each drilling fluid was then assessed against each issue to determine a best in class ranking, with a 1 signifying the highest rating. This process was undertaken by considering both documented evidence and empirical data.

4.2 SIGNIFICANCE ANALYSIS

The significance of the issues was based on two key factors:

- The frequency of occurrence of the issue
- The impact on the drilling programme that the issue could have

Three values were entered for the frequency and also again for the impact. The values based upon a most likely, a maximum (but not extreme) and a minimum (not 0). This ata once fed into a mote carlo simulation model for each of the line items defined allowed a distribution to be developed and a probabilistic median value taken from the resultant graphical analysis.

The Boston Square used to determine the relative significance of the issues is detailed in Table 3 below.

Table 3: Boston Square Analysis

Impact		Frequency of Occurrence				
		1	2	3	4	5
		Unlikely	Possible	Probable	Frequent	Very Frequent
5	Train Wreck	5	10	15	20	25
4	Severe	4	8	12	16	20
3	Significant	3	6	9	12	15
2	Minor	2	4	6	8	10
1	Negligible	1	2	3	4	5

A five by five matrix was found to be suitable to capture the permutations of different events that are experienced in drilling operations. A description of the categories is given below:

Impact

Train Wreck – Loss of well.

Severe – Serious financial/time implication/Serious defects etc.

Significant – Drilling programme impaired by lack of performance, due to a variety of reason

Minor – Impaired performance due to operational constraints and/or other unforeseen influences i.e. tool failure.

Negligible – Has little or no effect on performance i.e. lesson learnt.

Frequency of Occurrence

Unlikely – Under normal operations the activity does not occur

Possible – Under normal operations the activity could occur but the chances are remote

Probable – Under normal operations the activity has occurred in the past but not very often

Frequent – Under normal operations the activity occurs numerous times

Very Frequent – Under normal operations the activity all the time

The product of the impact and the frequency of occurrence is used to construct the significance ranking.

The significance ranking is used as a screening process to allow the study to concentrate on key significant issues. It is these issues that are modeled to create the output for the QRA. The screening process is achieved by breaking down the rankings into groups as detailed below:

	Negligible (N)
	Low (L)
	Medium (M)
	High (H)
	Very High (V)

The items falling into the negligible bracket were not considered further. A random selection of items from each of the remaining four categories was examined further to build the models for the QRA.

4.3 DATA GENERATION

The issues, which were deemed appropriate to consider further, were then split into two distinct parts:

- Those attributing to the impact on the time to complete a drilling programme, and
- Those which had a direct cost implication on the drilling programme

The time taken for a typical well programme was established for each case, as detailed in Table 2. It was assumed from research of the literature that for 50% of the time the Rate of Penetration (ROP) achieved using FBF would be 30% improved over both OBM and WBM.

Data was generated for two key parameters, which were integral to each model, namely ‘frequency of occurrence’ of an issue and the ‘impact on the timeline or cost’. This enabled the models to generate the additional time and cost involved in carrying out the drilling programme. This process was repeated for each drilling fluid and well type configuration for time and for cost.

4.4 MODEL GENERATION

The data generated for each pertinent issue outlined in section 4.3 was then sampled and representative probability distributions fitted to the data, to represent the characteristics of each issue.

For both additional time and cost, individual models were created to establish the impact of the issues on a typical drilling programme. In total 24 models were developed, to account for all the configurations of drilling fluid, well type for both additional time and cost were generated.

The issues relating to cost were split into those that can cause formation damage and those that cannot. To ensure that the model reflected the key stages within a typical drilling programme the issues were divided into the following sub section: drilling, reservoir completion, testing and any specific additional commercial issues. This assisted in the simplification of the modeling process and in turn the investigation of the impact of the issues at different stages of the drilling programme.

Each model was developed separately and took into account the following considerations to ensure that the model outputs were realistic and representative:

- When specific tasks and activities occurred in parallel.
- When specific tasks and activities only occurred as a result of a sequence of events.
- When specific activities overlapped part of the original estimates for the typical wells.

It should be noted that for all the issues considered, only a percentage of them would likely occur in any specific well. As a consequence, the results derived are likely to reflect the upper bound values of any benefits that can be predicted.

⁽³⁾The mathematical models employed Monte Carlo simulation techniques to derive output. The results from each model were used to create a Cumulative Distribution Function (CDF) representing each drilling fluid and well type for both additional time and cost.

S-curves were generated for each drilling fluid perceived depicting the four well types for the perceived additional time.

Stacked histograms were also generated for each of each drilling fluid perceived depicting the four well types for the perceived additional cost.

FBF was considered to be the base case for which all the other drilling fluid and well type configurations were compared. The relative performance of the other drilling fluid and well type configurations were derived and expressed as a percentage advantage or disadvantage over FBF.

5 RESULTS

5.1 Strengths and Weaknesses

The strengths and weaknesses associated with drilling fluid for each well type are tabulated in Appendix A of this report.

Each of the 80 issues considered were assigned a ranking in line with Section 4.1.

5.2 Significance Analysis

The results of the significance analysis outlined in Section 4.2 are tabulated in Appendix B of this report.

To establish where the issues impacted on the drilling programme the most for each drilling fluid and well type configuration, the issues were plotted on histograms to outline any differences. Figure 1 below summarises the distribution of the results for each drilling fluid.

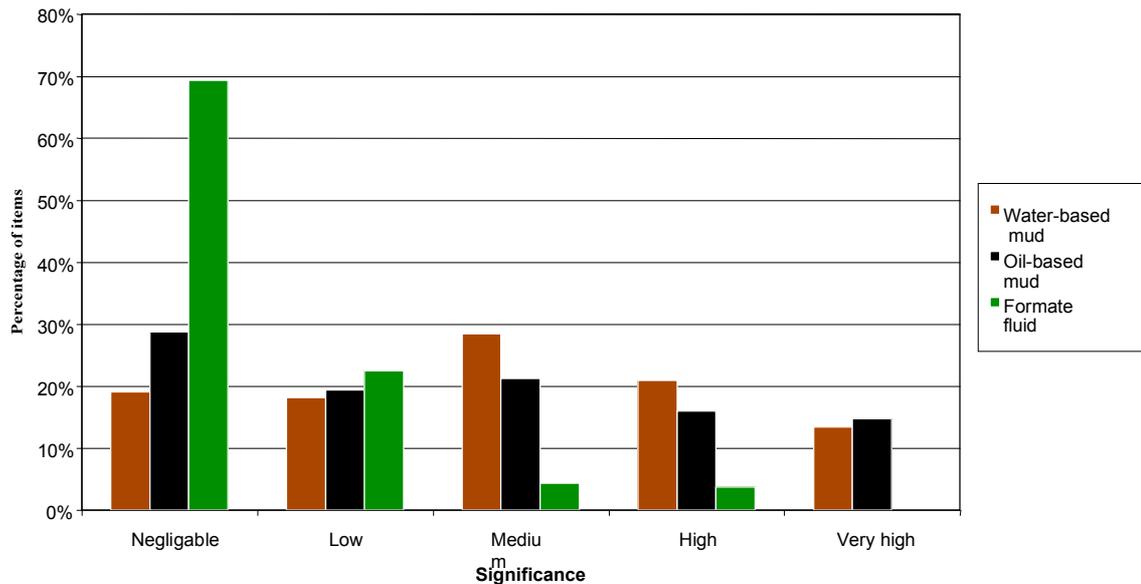


Figure 1: Drilling Fluid Summary – Significance Analysis

For the more detailed results highlighting the relative performance of each drilling fluid for each well type, see the histograms in Appendix C of this report.

5.3 Model Results – Total Expected Time Estimation

The results for the expected length of time for each drilling fluid and well type configuration have been summarised for the P50 figures in Table 4 below. The results have been formatted to

indicate the percentage increase/decrease in additional time (days) that would be taken to complete the drilling programme with respect to using FBF.

Table 4: Time Estimation – Percentage Advantage/Disadvantage over FBF Base Case

Well Type	Drilling Fluids	
	OBM	WBM
TTRD	+21%	+50%
HPHT	+3%	+16%
60 DEG ERD	+5%	+19%
90 DEG PROD	+8%	+13%

The potential time penalties (days) with respect to the base case Formate per well are tabulated below and represent the P50 cases derived from Table AD1.

Well Type	Drilling Fluids (Days Penalty)	
	OBM P50	WBM P50
TTRD	+ 6.35	+ 15.3
HPHT	+ 3.53	+ 18.86
60 DEG ERD	+ 4.87	+ 17.86
90 DEG PROD	+ 4.87	+ 7.86

Quite clearly there is a significant advantage with FBF relative to the OBM and the WBM over the well for all of the four well types.

The detailed tabulated results for the total expected time to complete the drilling programme (P10, P50 and P90 figures) including the associated S-Curves are included in Appendix D of this report.

5.4 Model Results – Total Expected Cost Estimation

The results for the expected additional cost (in £M) for each drilling fluid and well type configuration have been summarised for the P50 figures in Table 5 below.

Table 5: Total Expected Additional Cost In £M To Complete Drilling Program

Drilling Fluids	Well Types			
	TTRD	HPHT	60 DEG ERD	90 DEG PROD
OBM	2.34	2.37	2.44	2.44
WBM	0.76	0.79	0.86	0.86
FBF	0.46	0.53	0.66	0.66

Each cost estimate in Table 5 represents the scenario where there is formation damage caused. To ascertain the impact on the additional cost figures above as a result of no formation damage, the stacked histograms in Appendix E were created.

6 DISCUSSION

6.1 Strengths and Weaknesses

From the results in Appendix A and Section 5 it is clear that FBF comes out best in class for far more of the issues identified than either OBM or WBM. The evidence to back this up is also detailed in the table in Appendix A, from sources such as previous test reports, field testing to published research from the SPE.

6.2 Significance Analysis

The significance analysis detailed in Appendix B and Section 5 of this report indicates that FBF attributes far fewer mediums, highs and very high rankings than OBM and WBM. Over half are considered to be negligible. OBM and WBM give a similar distribution of results, with the only outlier being WBM with a high number of medium significance items for HPHT.

As a result there are fewer significant items to model for the FBF as opposed to OBM and WBM.

6.3 Total Expected Time Estimation

In each of the drilling fluid and well type configurations it has been demonstrated by the QRA that FBF presents a clear benefit with respect to expected additional time over both OBM and WBM. The benefits are more pronounced in the TTRD and HPHT cases.

In all cases OBM were demonstrated as the second best fluid in relation to time.

It was noted that for the 60 Degree ERD well the differences at the P90 level were diminished between OBM and WBM. In this case FBF was still shown to have clear benefit over OBM and WBM.

For the 90 Degree Producer well the relative advantage between FBF and OBM was similar to the advantage OBM displayed over WBM.

6.4 Total Expected Cost Estimation

The cost differentials that could be expected using one fluid as a replacement for another but for which base costs are discounted (cost of fluid itself) are shown by the histograms.

The costs are separated in to those that can be attributed to a result of damage to the formation and those that are distinct from formation issues.

FBF shows a clear cost benefit over both OBM and WBM, although the benefit was most pronounced in the case of OBM. This is substantially attributable to the cost for processing of OBM drill cuttings. Formation damage was only quantified in regard to the time and cost of operations that would take place to overcome formation damage such as re-perforating etc. It does not take account of lost production.

The second type of data depicted by the histograms show very clearly that the number of significant issues that could be attributed to FBF diminished with severity of Risk. In both the OBM and WBM cases, the largest number of issues could be found in the 'Medium' significance bracket.

7 CONCLUSIONS

A Monte Carlo modelling process was adopted to examine the expected difference in using OBM, WBM and FBF in a range of generic well types.

The results from the modeling show very clearly that there is a significant advantage in terms of time and cost (excluding base fluid cost) of using FBF as a replacement for the more commonly used OBM and WBM.

The significance analysis examined all the issues under consideration for each well and drilling fluid type combination. The results of this showed qualitatively that FBF had an advantage over the other fluids insofar as the majority of the items pertinent to FBF were categorised as being in the 'Negligible' and 'Low' significance brackets of risk. This was not the case with the OBM and WBM.

This suggests the potential for unwanted events and disruption taking place is greater when OBM and WBM are used. The results of the significance analysis are supported by the results from the main models.

It is worth noting that there are potential knock on effects of a secondary nature that were not considered in the modelling, which could impinge directly and indirectly on a typical drilling programme. This could cause additional time and or cost to a programme.

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APPENDIX A: STRENGTHS & WEAKNESSES