Predicting HP/HT Effects on the Flow Properties of Field Water Based Muds: Trials & Tribulations

Richard P Jachnik[1]

[1] Baker Hughes Drilling Fluids, Stoneywood Park North, Aberdeen, AB22 7EA, Scotland United Kingdom

ABSTRACT

A method to predict the effects of temperature and pressure on the flow properties of any field water based mud utilising limited well site data is outlined. Data will be presented to demonstrate the level of engineering accuracy obtainable based on field observations carried out on a recent HP/HT well drilled in Europe.

INTRODUCTION

Flow properties of drilling muds are measured at drilling locations using couette type viscometers fitted with a large gap and have been described by the author[1] elsewhere. The purpose of these measurements is multifunctional. Primarily, viscometer data are simply used as a comparative measure from one day to another against desired specifications (normally based on experience). These specifications are set to provide boundaries for acceptable parameters and help to determine mud treatment. The main parameters currently used by the industry are plastic viscosity and yield point as determined by the Bingham fluid model.

Secondarily, viscometer data (as a stress value) is also input into hydraulics models to determine pressure losses throughout various parts of the circulating system as well as other relevant hydraulics information.

Increasing temperature significantly decreases the viscosity of water and in high temperature wells (those with temperatures in excess of 150°C) – water based mud flow properties may be different to those measured at standard surface temperatures depending on various combinations of additives and solids as well as temperature effects on the composition. Drilling mud flow properties are usually measured at some constant temperature to assess trends. This is usually 48.9°C (120°F) but higher temperatures are often used for HP/HT wells (up to 65°C -150°F).

The pressure effect on water is quite small and so the expectation is that pressure effects on water based drilling muds will also be small (and is confirmed in this study).

Some authors[2] have recently described 3 tiers of HP/HT operating environments and make a distinction between “Standard” HP/HT, Extreme and Ultra, based on reservoir temperature and pressures. The well discussed in this paper does not fit neatly into these predetermined categories as bottom hole pressure would be called extreme but the temperature ultra! - as the measured bottom hole temperature (BHT) was 256°C with static pressures in the range of 17000 psi (117 MPa).

HP/HT viscometers that can measure flow properties at pressures up to 20,000 psi (138 MPa) with temperatures up to 250°C are now common in mud laboratories and a newer model has recently been developed[3] that is capable of 315°C and 276 MPa.

Other viscometers are available that can measure up to 260 deg C and 1000 psi (MPa). These are less complex and of slightly lower cost but currently are rarely used on rig locations. Obtaining good quality data with any of these instruments is a more time consuming process than with the simple atmospheric viscometers and requires extra time of already busy mud engineers. Cost, data quality and safety considerations also mean that the high pressure instruments are confined to advanced mud laboratories. While samples of drilling mud can be transported from field location to mud laboratory, the time taken in transporting samples from remote locations can result in measurement of different flow properties especially if the mud is quite thixotropic. Results may also not reflect current values at the drilling location..

HP/HT viscometers are run to obtain a matrix of data points (stress values) covering various pressure and temperature combinations from surface down to actual drilling depth. The matrix is then input into sophisticated hydraulics models to give more accurate pressure loss outputs for various parts of the hydraulic circuit and can also affect hole cleaning calculations. Lack of relevant data for well planning purposes often means that simple hydraulics calculations are run even though the planned well is regarded as HP/HT. Optimum performance and understanding is desired as operating costs are usually extremely high in these environments.

Maglione[4] and co-workers have written several papers on the general concept of using the well as a viscometer and also published a comprehensive set of equations for pressure loss with Herschel Bulkley fluids in circular and annular sections. However their work did not really address high temperature effects as seen by aqueous fluids in hot wells.

AVERAGE FLOW PROPERTIES

Measurement of mud flow properties at a drilling location will always be correct for calculation purposes if it is measured at the average condition of temperature and pressure prevailing in the well at the time of interest. To obtain this average condition we require knowledge of the geothermal gradient, the circulating temperature at the surface as well as maximum pressure while circulating or drilling on bottom.

Measurement while drilling tools can record mud temperatures close to the bit but their use is typically limited to muds where the circulating or static temperature is below 160°C, although research is currently underway on tools capable of 200°C. So for high temperature environments we require an alternative method of estimating downhole circulating temperatures.

Kutasov[5] has developed some empirical equations to estimate maximum temperature while circulating. However, while the operating conditions of the subject well were outside the limits of the coefficients used in his equation, derived values were compared to other thermal modelling methodologies and felt to be realistic. For a bottom hole temperature of 256°C and a surface circulating temperature of 57°C the equation yields a maximum circulating temperature of 188°C with an average well temperature of 122°C. HP/HT hydraulics modelling with one particular software package eventually gave a value on bottom of 175°C and a maximum temperature of 187°C ~ 700 m from bottom (about 12% of well depth) and so correlated quite well with the empirical output. Another software package predicted much lower circulating temperatures which were felt to be unrealistic based on various field observations and hydraulics modelling. The cause for this is still under investigation as is the true thermal conductivity and specific heat capacity of the mud in use.

Maximum circulating pressure can initially be derived from standard hydraulics software, as whether this is out by 1000-2000 psi (6-14 MPa) will make no difference to obtaining satisfactory results for engineering calculations. In the field example first discussed, the average pressure is 9500 psi (65.5 MPa).

If the flow properties of the standard mud check are input into any hydraulics model, the result should be too high a pressure calculation if the values are thicker than the average condition and too low if the test temperature is higher than the average circulating well temperature. This of course assumes that any available flow model in the hydraulics software fits the measured flow properties with sufficient accuracy. 3 parameter flow models are usually sufficient. (High temperatures can affect static densities so these may need to be adjusted slightly once some range finding HP/HT hydraulics have been run).

In the well example, all tests run at 60°C gave too high a standpipe pressure loss (standpipe pressure or SPP is measured after the mud pumps and is the sum of all pressure losses in the circulating system) - so indicating that the mud flow properties at the average temperature and pressure condition were thinner than these values. The question then becomes – How can we obtain these values?

WATER

A large body of data exits in the American National Institute of Standards and Technology (NIST) water tables for pressures up to 20,000 psi (138 MPa) and temperatures up to 200 °C. For temperatures up to 250°C it was necessary to extrapolate with 2D graphing software the data of interest viz: viscosity and volume. Water has a maximum density and volume of 1 at 3.984°C. Increasing temperature decreases density and increases volume. The viscosity of water is often assumed to be 1 mPa.s but is only this value at 20°C (1.002 mPa.s). At 60°C, (the example standard reference temperature), water has a viscosity of 0.468 mPa.s with a volume of 1.017 ml/g when determined with curve fit analysis from NIST data.

Standard oilfield viscometer dial readings are then related to increasing temperatures and pressures by using the ratio of viscosity and volume at mud check temperature to higher temperatures and pressures. This assumes that the mud contains only water and solids and would only be accurate if this were actually the case. No stable mud can have values lower than these as any additives must increase the viscosity of water. If a mud is temperature unstable, then thermal degradation of additives may lead to a very significant collapse in dial readings. Any values lower than those calculated would show a thermally unstable system.

An example of these derivations can be seen in Table 1 below - which is split for space

Table 1. Comparative Dial Values Derived for Water and Solids at Varying T&P

water vis mPa.s	ratio to test temp	volume ml/g	Solids %	Temp °C	Pressure psi
0.468	**1.000**	**1.017**	**38**	**60.0**	**14.5**
0.718	**1.533**	**1.006**	**38.419**	**35**	**14.5**
0.249	**0.531**	**1.028**	**37.599**	**120**	**9500**
0.174	**0.372**	**1.049**	**36.846**	**185**	**20000**

RPM 600 Dial	RPM 300 Dial	RPM 200 Dial	RPM 100 Dial	RPM 6 Dial	RPM 3 Dial
91	**55**	**40**	**25**	**8.0**	**7.0**
139	**84**	**61**	**38**	**12.2**	**10.7**
49	**29**	**21**	**13**	**4.3**	**3.7**
34	**21**	**15**	**9**	**3.0**	**2.7**

While oilfield viscometers have at best an accuracy of ±1 in dial reading at low speed, the spreadsheet output was altered to ±0.1 to better distinguish data for use in one particular hydraulics software program. Solids are assumed to be incompressible or insignificant for calculation purposes.

SALT

Drilling muds usually contain some chlorides and minor amounts of other soluble elements, but sodium chloride salinity dominates. A search of the literature showed a paucity of data when compared to the NIST water tables.

Kestin[6] published data on the viscosity of NaCl solutions in 1978 using an oscillating disk viscometer but this is limited to 150°C and 30 MPa. Rowe and Chou[7] published data on pressure volume temperature relationships in 1970 and while their data went up to 174.4°C, it was limited in pressure to 300 atm (30.4 MPa).

Viscosity data could be extrapolated based on good 3D curve fits up to much higher temperatures and pressures and agrees well with the atmospheric data outlined in the data-book by Phillps[8] and co-workers.

Rowe and Chou compressibility data could not be extended out of their measurement range based on their proposed equation. This is thought to be due to the polynomial used.

Typical mud salinities in the field example were in the order of 13% NaCl concentration and at temperatures of 184°C and 19,000 psi (131 MPa) the viscosity is calculated to be 0.235 mPa.s. Due to there being 4 variables (viscosity, temperature, pressure and salinity) the approach taken was to derive viscosities at desired temperature, at a fixed pressure of 18,000 psi (124 MPa) and then interpolate for varying pressure.

Eq. 1 derives the viscosity in mPa.s where x is the NaCl salinity in wt % and y the temperature in °C. Table 2 shows the coefficients of this equation.

$$z=(a+cx+elny+gx^2+i(lny)^2+kxlny)/(1+bx+dlny+fx^2+h(lny)^2+jxlny) \quad (1)$$

Table 2. Coefficients for NaCl viscosity at atmospheric pressure, varying temperature

Parm	Value				
		d	-0.34518	h	0.042334
a	1371.585	e	-479.369	i	43.51173
b	-0.00745	f	-0.00014	j	0.00273
c	12.71227	g	0.035512	k	-2.07643

Eq. 2 derives the viscosity at a fixed pressure of 18,000 psi (124 MPa). Values at other pressures are then obtained by linear interpolation.

$$z=(a+bx+cx^2+dx^3+elny+f(lny)^2)/(1+gx+hx^2+ilny+j(lny)^2) \quad (2)$$

Table 3. Coefficients for NaCl viscosity at 18,000 psi (124 MPa), varying temperature.

Parm	Value				
		d	-0.00315	h	-0.0000112
a	1022.5566	e	-303.11820	i	-0.4027398
b	-0.30448	f	24.28014	j	0.0613284
c	0.13946	g	-0.00581		

Baker Hughes Drilling Fluids recently collected some high pressure high temperature NaCl density data with a new crystallisation cell that can operate to 20,000 psi (138 MPa). Some of this data at a fixed salt concentration of 19.2% was curve fitted with 3D software to obtain relevant volumes at varying temperatures and pressures. As the density of salt solutions do not exhibit a maximum at the same temperature as water, 20°C was used as the reference temperature for unity volume. It was found that the volume change for this salt brine was relatively small so linear interpolation was carried out for the field mud salinity as this was felt quite adequate for engineering calculations. If we assume the mud only contained salty water and solids we can see that the effect of salinity is relatively small when Table 1 is compared to Table 4.

Table 4. Comparative Dial Values Derived for 13% NaCl brine and Solids at Varying T&P

salty vis atm press mPa.s	salty vis @ 18000 psi	salty vis actual	ratio to test temp	Vol. ml/g	Solids %
0.621	**0.667**	**0.621**	**1.000**	**1.022**	**38.000**
0.934	**0.994**	**0.935**	**1.506**	**1.008**	**38.508**
0.316	**0.351**	**0.335**	**0.539**	**1.022**	**37.986**
0.205	**0.233**	**0.236**	**0.381**	**1.037**	**37.440**

T °C	Press. psi						
		600	300	200	100	6	3
		Dial	Dial	Dial	Dial	Dial	Dial
60	**14.5**	**91**	**55**	**40**	**25**	**8.0**	**7.0**
35	**14.5**	**136**	**82**	**60**	**37**	**11.9**	**10.5**
120	**9500**	**49**	**30**	**22**	**13**	**4.3**	**3.8**
185	**20000**	**35**	**21**	**15**	**10**	**3.1**	**2.7**

This spreadsheet is known as the salty water predictor (SWP).

FIELD EXAMPLE

Non drilling well operations provided several instances where the methodology outlined in this paper could be tested. Prior to running casing at total depth (TD), the well, containing a simple drill string configuration, was circulated and a surface pressure of 1850 psi measured. Viscometer readings taken at 60°C when input to the standard hydraulics software gave surface pressures of 1900 psi and 1854 psi depending on whether the Herschel Bulkley or Robertson Stiff rheological model was used. At first sight this may appear a good result. However the differences in fit between the models were very close (98.77% and 98.61% respectively). On the basis that the best fit model (Herschel Bulkley) gives too high a value or making the argument that since the model fits are so close they should bracket the observed pressure, the SWP was used to generate a range of values at higher temperature.

When the flow properties at 65°C from the SWP were used and the density decreased slightly by 0.1 ppg (0.012 SG) to account for thermal effects on density (obtained with use of HP/HT hydraulics), the calculated surface pressures bracket that observed. The Herschel Bulkley model result decreased to 1865 psi with the Robertson Stiff model result at 1815 psi.

A matrix derived solely from the SWP used in HP/HT hydraulics gave a surface pressure of 1521 psi with the Herschel Bulkley model and as expected, was lower than measured. If the 6 speed viscometer readings are compared for the average condition of 122°C and 9500 psi, the SWP gives 48, 29, 21, 13, 4.2, 3.7 vs the true average as defined by the 65°C values of 85, 51, 37, 23, 7.5, 6.5.

A new matrix was then produced according to the hydraulic HP/HT software requirements. Outputs gave values of 1895 psi for the Herschel Bulkley model and 1832 psi for the Robertson Stiff model. When temperature in the SWP was increased to 72°C and a new matrix generated, the results were 1851 psi for the Herschel Bulkley model and 1790 psi for the Robertson Stiff model. The dial values derived in this second matrix can be seen in Table 5.

While they give reasonable pressure results there is no way of knowing at this stage of how inaccurate they may be. The top line in the Table is the measured data. This also raises the question “to what level of accuracy do dial values have to be to generate satisfactory hydraulics calculations”?

Table 5. HP/HT Matrix Dial Values Derived from SWP and average well condition

T °C	Press. Psi	600 rpm	300 rpm	200 rpm	100 rpm	6 rpm	3 rpm
60	14.5	91	55	40	25	8.0	7.0
35	14.5	136	82	60	37	12	10
122	9500	78	47	34	21	6.8	6.0
50	5000	94	57	42	27	9.2	8.2
60	6000	92	56	41	26	9.2	8.2
70	1000	89	54	39	25	8.0	7.0
80	8000	88	54	40	25	9.3	8.3
200	20000	65	41	31	21	9.5	8.8
100	3000	83	50	37	23	7.9	7.0
110	12000	83	51	38	25	9.5	8.6
120	13000	81	50	37	24	9.5	8.7
130	8000	78	48	35	23	8.3	7.5
140	15000	77	48	36	23	9.6	8.8
150	11000	74	46	34	22	8.6	7.8
160	18000	73	46	34	23	9.8	9.0
170	14000	70	44	32	21	8.8	8.1
185	20000	68	43	32	22	9.7	9.0
72	14.5	88	53	39	24	7.8	6.8

CIRCULATING CASING

Casing was run open ended to near TD and the well circulated. While the mud out temperature reached 62°C which was above the temperature of the mud check of 60°C, HP/HT hydraulics calculations did not show as high a surface pressure as that measured. Calculations were low by 24%. The cause of this is thought to be a build up of gelled mud/filter cake around the type of casing centralisers used. Using an SWP temperature of 70°C and expanding the dimension of the centralisers slightly from 8.25” to 8.5” the calculated pressure with the Herschel Bulkley model is 1410 psi vs a measured value of 1450 psi.

CIRCULATING CASING (2)

The well was then reverse circulated (flow down the annulus and up the inside of the casing) at a lower flow rate.

It was noticed that the surface pressure continued to increase indicating that the mud flow stress was below the structuring stress. Pressure increased from 550 psi to 930 psi in the space of 2 hours with an increase in temperature at surface of 4°C. The mud flow was then increased with pressure peaking at 1350 psi. It then decreased as now the flow stress exceeded the structuring stress and stabilised within 4 hours to between 830-840 psi for a period of over 12 hours.

Analysis of this latter stable period shows a constant temperature out of 62°C. Using an SWP temperature of 70°C and dial readings of 70, 42, 31, 19, 6.1, 5.2 the Herschel Bulkley model gives 845 psi and the Roberston Stiff model 815 psi using an average hole diameter of 8.75” (3% oversize) and allowing for the casing centralisers.

Currently the HP/HT hydraulic model cannot be run with reverse circulation so all modelling in this scenario was with average well values.

Inference from hydraulic modelling is that some gelled mud/cake around the casing centralisers had been collected while they were run in the hole. Reverse circulation down the annulus cleaned this obstruction.

One can only surmise as to the flow properties during the low circulation rate as the mud began to structure. However there are some clues. The maximum Newtonian shear rate inside the narrower casing was $64\ s^{-1}$ and $83\ s^{-1}$ during the stabilised period, so we know that gel structure is collapsing between these two shear rates. (True shear rates in annuli will vary slightly depending on rheological fluid model but will be within 3% of these Newtonian values). As mentioned by Herzhaft[9] et al, a shear rate discontinuity most likely exists between the interface of the flowing and non flowing regions and so modelling with standard rheological flow models must be inadequate.

While all aqueous muds at high densities are thixotropic to some degree, the standard oilfield “gels” at 60°C as measured at the drilling location were only 6/15/19-21 for 10 s/10 min/30 min during this period. (Dial readings are usually measured in units of lb/100 ft^2 and have to be converted to Pa by multiplying by 1.0678*0.4788).

Fitting the modified API Power Law flow model to a postulated data set yields pressures close to those observed at the two different flow rates (956 and 1228 psi respectively). Model selection is limited to those coded in software - so while not perhaps ideal, simulation helps confirm the suspicion that significant thickening occurred when shear rates were below 64 s^{-1}. Some idea of these flow properties is shown in Fig. 1. The cause of the increase in structure is thought to be due to high temperature effects on the mud composition.

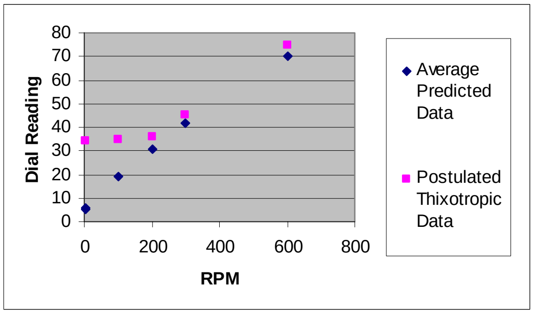

Figure 1. Predicted average dial values during stable and unstable periods

Best modelling results for the start of the unstable period were obtained when a temperature of 70°C was used in the SWP for the average well values with no allowance for any gelled mud or filter cake and open hole dimension of 8.75".

A best fit Herschel Bulkley model then gave 548 psi for the initial pressure and 463 psi with Robertson Stiff before the mud began structuring.

A distinct gel breaking peak can be seen in Fig. 2 which occurred after only 6 minutes rest. The pressure increased from 933 psi up to the maximum of 1350 psi as the mud pumps were restarted then declined to background in ~27.5 mins.

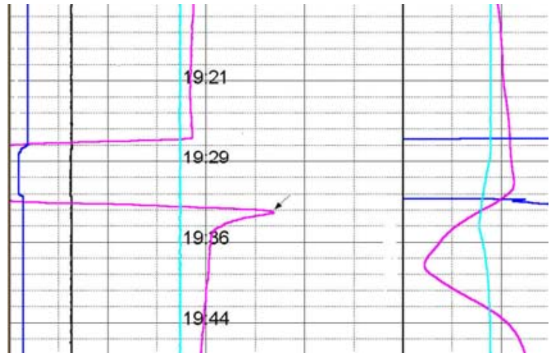

Figure 2. Gel peak after only 6 minutes rest- an increase of 417 psi

CONCLUSIONS

It is possible to generate a suitable matrix for HP/HT hydraulics analysis of any water based mud provided a 6 speed viscometer data set is available at mud check temperature and atmospheric pressure. Also required is knowledge of mud salinity, geothermal gradient, flowline temperature and standpipe pressure.

It remains to be seen whether significant variances could exist for data within any matrix.

Use of expensive high temperature low pressure viscometers at well location would be able to validate predictions. They would also allow monitoring of structure building at lower shear rates, and provide better information for mud treatment.

Current viscometers that simply measure flow properties at surface conditions cannot provide this important information.

ACKNOWLEDGMENTS

The author would like to thank Baker Hughes Drilling Fluids management for their support in preparing this paper and field engineering staff who demonstrated the capability to drill to above 250°C with high density, solids laden water based mud.

REFERENCES

1. Jachnik, R.P. (2003), "Low Shear Rate Rheology of Drilling Fluids", Annual Transactions of the Nordic Rheology Society, Vol 11, 21-27.

2. Maldonada, B., Arrazola, A., and Morton, B., (2006), “Ultradeep HP/HT Completions: Classification, Design Methodologies and Technical Challenges” Offshore Technology Conference paper OTC 17927.

3. Gusler, W., Pless, M., Maxey, J., Grover, P., Perez., J., Moon, J., and Boaz, T. (2006) “A New Extreme HP/HT Viscometer for New Drilling Fluid Challenges”, IADC/SPE 99009

4. Maglione, R., Robotti, G., and Romagnoli, R, (2000), “In-Situ Rheological Characterization of Drilling Mud”, SPE Journal Vol 5, #4, 377-385

5. Kutasov, I. M. (1995), “Empirical Equation Estimates Geothermal Gradients”, Vol 93, Jan 2.

6. Kestin J., Khalifa, H.E., Yoshiyuki, A., Grimes, C.E., Sookiazian, H., and Wakeham, W. (1978), “Effect of Pressure on the Viscosity of Aqueous NaCl Solutions in the Temperature Range 20-150°C, Journal of Chemical and Engineering Data Vol 23, #4, p328-336

7. Rowe, A. M. Jr., and Chou, J. C. S. (1970), “Pressure-Volume-Temperature-Concentration Relation of Aqueous NaCl Solutions”, Journal of Chemical and Engineering Data, Vol 15, No.1, p61-66.

8. Phillips, S. L., Igbene, A., Fair, J, A., Ozbek, A., and Tavana, M. “A Technical Databook for Geothermal Energy Utilization”, Lawrence Berkeley Laboratory, UCA, 1981

9. Herzaft B., Ragouillaux A., and Coussot, P., (2006) “How to Unify Low-Shear-Rate Rheology and Gel Properties of Drilling Muds: A Transient Rheological and Structural Model for Complex Well Applications”, IADC/SPE 99080