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The Top 10 Myths, Misconceptions and Mysteries in Rheology and Hydraulics

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Abstract

This paper explores misunderstandings and confusion that drilling personnel have about rheology, hydraulics, and their effects on field operations. The top 10 myths, misconceptions, and mysteries are identified and discussed to find common ground to bridge existing technical and philosophical gaps.

Drilling fluid rheology and hydraulics are complex but important topics to rheologists, chemists, modelers, software developers, engineers, and wellsite personnel. While some deal with ideal flow behavior in controlled settings, mud engineers and drillers focus on practical consequences of rheology and hydraulics in operations fraught with uncertainty. Drilling fluid developers must address the full range of issues, usually based on tests run under artificial conditions that may not duplicate the actual drilling environment. Thus, it is no surprise that perceptions of rheology and hydraulics differ widely and agreements suffer.

Introduction

It was a challenge to select the top 10 myths, misconceptions, and mysteries in drilling fluid rheology and hydraulics because of the countless candidates from which to choose – a broad spectrum from the very basic to the highly theoretical – and the varied perspectives of those concerned with these complex topics. The final list, organized for best continuity in this paper, includes six titles on rheology followed by four on hydraulics – each with multiple items and all targeting engineers charged with applying these technologies in the field.

Issues develop when disconnects in a "rheochain" interfere with monitoring and adjusting fluid behavior in response to well conditions. This chain involves rheologists that study and explain; chemists that formulate and commercialize; modelers that measure and relate; software developers that compile and disseminate; engineers that plan and optimize; and wellsite personnel that apply and adapt. The rheochain seems also to thread its way from the nano to the mega-bbl scale.

Issues can morph into myths, misconceptions, and mysteries when the science is misunderstood, over-simplified, obscured by uncertainties, or complicated by downhole conditions that markedly change the fluid. Sometimes, math by those detached from the field is at odds with the physics. Other times, researchers using polymers to "viscosify" fluids are unaware of "rheological" consequences.

Selections for the list were based on the following distinct but closely related fit-for-purpose definitions:

- *Myth*: a belief or result of questionable validity, often lacking scientific support and known authorship.
- *Misconception*: a mistaken or misunderstood view that could lead to misapplication of technology.
- *Mystery*: an unexplained behavior or a problem that continues to elude practical solution.

Terminology and oilfield jargon often have been a source of confusion, especially among those along the rheochain. However, standardization and general acceptance of terminology within the industry have helped considerably. The value of standardization, particularly by the American Petroleum Institute (API) Subcommittee 13 on rheology and hydraulics of drilling fluids, cannot be overstated.

Rheology is classically defined as the study of the deformation and flow of matter. However, Morrison (2004) added that "Rheology is the study of the flow of materials that behave in an interesting or unusual manner. Oil and water flow in familiar, normal ways, whereas mayonnaise, peanut butter, chocolate, bread dough and Silly Putty flow in complex and unusual ways." To some degree, all drilling fluids behave in unusual ways *by design*, and many can easily fit into Morrison's list.

Hydraulics deals with fluids in motion and at rest, as well as the motion of particles through them. Unfortunately, flow properties ideal for the performance of one fluid function in the drilling process frequently are detrimental to another. Thus, the drilling fluid properties selected in the field and measured under less-than-ideal conditions often represent an engineering compromise.

Some elements of drilling fluid rheology and hydraulics truly are complex in their own right and difficult or even impossible to manage under downhole conditions. For good reason, complete resolution to the top 10 myths, misconceptions, and mysteries is not a goal of this paper. Instead, the intent is to provide a few useful nuggets for readers from different perspectives. To some, certain parts might seem too simplistic, too complex, too obvious, or too obscure. Even the mysteries perhaps are explainable by someone under the right conditions. Ample references are provided. After all, "art" usually comes into play when the science, physics, and engineering are just out of reach of the person charged with applying the technology.

1. Funnel Viscosity – technology past its prime?

The Marsh funnel, the oldest and most used equipment for measuring drilling fluid viscosity, is also the most maligned. Those that argue for its demise because the single-point measurement can be misleading, misinterpreted, and misapplied should appreciate the funnel's value for statistical process control. Those that embrace its simplicity, low cost, and ability to detect changes in circulating fluid properties might consider whether it alone can properly validate mud consistency in a 250-bbl mixing tank. And finally, those that find it mysterious that weighting up certain muds can lower funnel viscosity should consider the increased hydrostatic head acting on the fluid.

Surprising to some, the Marsh funnel is an ASTM standard (ASTM 2009), as well as an API standard (API 2005, 2009). Rather than providing a conventional viscosity, it is the time in seconds for a quart or liter of fluid to flow through a small tube under a gravity head. Nevertheless, Pitt (2000) used numerical simulations and several sophisticated test devices to estimate an effective viscosity μ_e (cP) based on mud weight ρ (s.g.) and funnel time t (s/qt):

$$\mu_e = \rho(t - 25) \qquad \text{(Eq. 1)}$$

The value of this calculation notwithstanding, imagine the confusion created by reporting funnel "viscosity" in units different than those which have been used, accepted, and mostly understood for over 80 years.

Unfortunately, few drilling fluids can be characterized by this single-viscosity measurement. This means that the data cannot be used to calculate pressure loss and treat muds. Marsh (1931) recognized both the value and limitations of his creation from the onset, admitting that readings are only "comparative" and are "really a combination measure of yield value and plasticity that gives only a practical indication of fluidity." More recently, Pitt (2000) expressed the feelings of many by stating that "generations of mud engineers have adjusted and controlled drilling muds with this device, and [his] own experience of using the funnel led him to feel that there was a genuine pattern, probably those recognized intuitively by experts in the field."

The Marsh funnel is used with all types of drilling fluids, but this does not mean that a reasonable comparison can be made among them. Polymer fluids can respond differently to the convergent shape of the funnel due to their *extensional viscosity*, as compared to the familiar *shear viscosity*. Results may be mysterious since the effects are difficult to quantify.

The funnel is so entrenched in the oilfield that it likely will remain a mainstay indefinitely. Indeed, its process-control feature is being advanced by vibrating-rod and simple inline viscometers used for automated mud measurements. These modern viscometers are accurate and robust, but like the funnel cannot measure true viscosity of a fluid whose flow behavior is not previously known.

Bottom line: Marsh funnel viscosity is a good indicator of overall fluid consistency and it use should be continued; but it does not characterize flow behavior of complex fluids.

2. Rheological Measurements – is that all there is?

The venerable rotary viscometer has been the industry workhorse for measuring drilling fluid rheology for over 60 years. Its success and longevity are attributable to the ingenious design by Savins and Roper (1954) based on simplicity, reliability, compactness, and robustness. Geometry and test protocols have been adopted by today's sophisticated HTHP and electronic viscometers. But like the funnel, the concentric-cylinder rotary viscometer has some limitations.

Known as "V-G" meters, they are quite suitable for measuring shear viscosity ("V") and gel-strengths ("G"). Along with a few derived parameters, these are known collectively as the "drilling fluid rheological properties," or more simply, the "mud rheology." Either reference is a misnomer, since information from the viscometer are but a subset of the true rheological properties and is insufficient to characterize rheologically complex fluids.

Rheologically, drilling fluids are *thixotropic* (time-dependent) by design, and temperature and pressure-dependent by nature. They also are *viscoelastic*, meaning that they exhibit both viscous and elastic properties. Unfortunately, suitable rheometers that measure more than just the viscous properties, such as those described by Maxey (2006), are not very rig or mud friendly, and currently are confined to the laboratory for research and development purposes.

For illustration, rheologists like to compare a partly used jar of mayonnaise (top surface retains the shape created by the last person to make a sandwich) and a jar of honey (top surface is always smooth). Honey is more viscous, but the viscoelastic and thixotropic properties of mayonnaise cause it to maintain the surface shape (Morrison 2004).

Fluids that behave like mayonnaise or honey are unsuitable for drilling. However, two example water-based drilling fluids are among those recognized for their unique rheological behavior and proven field performance. One is formulated with a mixed-metal oxide (MMO) bentonite extender (Fraser *et al.* 2003), while the other relies on a biopolymer and avoids bentonite (Beck *et al.* 1993). Both fluids can have a semi-solid appearance when at rest, but they fluidize easily and are easy to pump. They provide remarkable suspension and very quickly develop a non-progressive gel structure after coming to rest. Both also rely on field experience guided by traditional flow indicators for proper engineering. In the case of the biopolymer fluid, empirical correlations based on measurements taken with non-standard viscometers at the wellsite have proven successful and continue as standard operating procedures in the field (Beck *et al.* 1993). This suggests that special test devices may be useful to augment data measured on current viscometers.

The 600 and 300-rpm sleeve speeds of the original V-G meter are included on the popular 6-speed version, as well as the 8, 12, and variable-speed viscometers (including HTHP units) now offered. In all cases, the sleeve rotates around a stationary bob to minimize instabilities (Taylor vortices), and readings are always taken from high-to-low speeds to minimize structure-building effects. **Fig. 1** illustrates a test using a digital viscometer with data export capabilities.

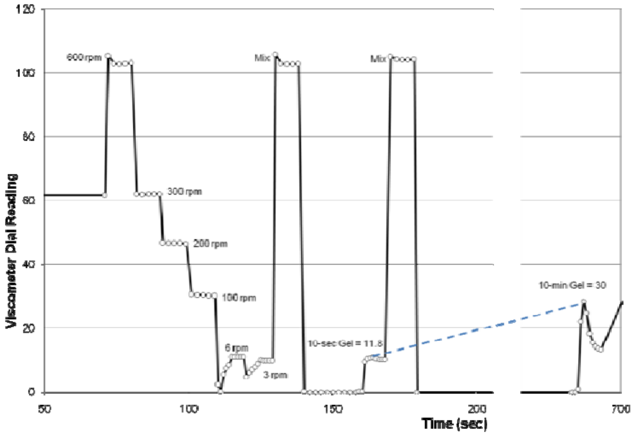

Fig. 1: Typical viscometer run. Dashed line shows gel-strength trend.

The 600 and 300-rpm speeds are still in use to calculate plastic flow parameters that are fundamental to drilling fluid engineering. Although considered high shear rates, the speeds were selected because they exceed the theoretical critical speed that avoids plug flow in the gap between the sleeve and the bob (Savins and Roper 1954). Moreover, the 300-rpm dial reading (R_{300}) at 511 s^{-1} is the same as the fluid viscosity (cP) at that shear rate. Other "equivalent" viscosities are easily calculated by multiplying the dial reading by the ratio of 300 over the selected viscometer speed. Purpose of the API "apparent" viscosity (one-half of R_{600}) was to provide a quick check on whether the fluid was Newtonian. Unfortunately, this "apparent" viscosity term is often confused with "effective," "equivalent," and "Newtonian equivalent" viscosities that have different meanings to those in the rheochain.

Newtonian fluids are well known for their constant viscosity; however, this is a misconception because fluid viscosity is never constant. Viscosity, even if independent of flow rate or viscometer rotary speed, changes with other parameters such as temperature. This alone is enough to question if steady-state conditions are ever achieved downhole.

Field viscometer test temperature brings its own set of myths, misconceptions and mysteries. For example, water-based muds usually are tested at 120°F and oil-based muds at 150°F, the latter perhaps a carryover from a myth that this would make early, viscous asphaltic oil muds more acceptable. API (2005) specifies that either temperature can be used for oil muds. For water-based muds, the current API (2009) bulletin specifies testing within 10°F of the drilling fluid temperature at the place of sampling. And finally, barite is known to settle out while heating and stirring a weighted mud sample in the viscometer cup, but the impact on rheology measurements has not been quantified.

Consistent test conditions assist with evaluating fluid behavior; however, downhole temperatures and pressures follow complex and transient profiles, especially in deepwater and HTHP environments. Field viscometer readings, even if run at multiple temperatures, must be synchronized with laboratory HTHP testing and downhole conditions.

Furthermore, extreme conditions can markedly change the drilling fluid physically and chemically, and create new levels of complexity in rheological measurements. For deepwater drilling, innovative "flat-rheology" fluids have been developed to reduce temperature effects on rheology (Lee *et al.* 2004). These fluids are characterized by low-end rheology, yield points, and gel strengths that are relatively temperature independent. A key practical consequence is that a balanced rheology maintained throughout the mud column can provide optimum hole cleaning, fast drilling, and negligible barite sag, with minimal effects on equivalent circulating density (ECD) even when the fluid in the riser is exposed to very cold water temperatures for extended periods.

Bottom Line: The API-standard viscometer is an excellent device for measuring rheological properties of drilling fluids. However, it does not measure some rheological properties that are important to certain fluids. Consequently, use of a non-standard rheometer may be in order. Rheological properties should be adjusted to reflect downhole conditions, regardless of whether or not the drilling fluid automatically adjusts its rheology to help counter ill effects of the downhole environment.

3. Rheological Parameters – the right stuff?

Rheological mud parameters are used to study, formulate, mix, treat, monitor, model, and simulate drilling fluids. They also help evaluate consequences of fluid flow behavior. Critical decisions made continually based on these parameters are sometimes compromised by myths, misconceptions and mysteries.

Oilfield parameters are derived from viscometer testing and different time-independent rheological models. Plastic viscosity (PV) and yield point (YP) are based on the Bingham-plastic model. Flow-behavior index (n) and consistency-factor (k) are parameters from the pseudoplastic (power-law) model and from the yield-pseudoplastic (modified power-law) model when yield stress (YS or τ_y) is included. Yield stress can be measured or derived mathematically from the modified power law. Logically, all of these parameters, like the fluids themselves, are temperature and pressure dependent.

PV, YP, and YS as defined by API standards are arguably the best parameters to use for mud engineering. The n value also is useful for solids-free, polymer muds with no yield stress, but the k value suffers from lack of unit-set consistency and practical mud engineering guidelines. Furthermore, n, k, and τ_y values are not independent of each other. Even the n value can be misinterpreted if the model source (power law or modified power law) is not specified. Based on field experience, for example, hole cleaning can be improved by lowering the n value of a power-law fluid and by increasing the τ_y value of a modified power-law fluid. The latter unfortunately increases the n value. Kenny *et al.* (1996) provide a good summary of how different n values affect drilling fluid performance.

Mud School 101 teaches how PV and YP have physical and chemical significance, and unlike other parameters, can be adjusted independently, for the most part. Failure to recognize interrelationships among parameters has led some researchers to apply mathematics that is at odds with the physics. For example, Maglione *et al.* (1999) illustrated how optimized changes in n, k, and τ_y could significantly improve drilling hydraulics. **Table 1** shows their initial and optimized values in rows 2-4; calculated values based on these parameters are listed in the bottom five rows. Aside from unusual initial properties, optimized rheology would require a PV of 0.8 cP, unobtainable for a 16-lb/gal drilling fluid.

Table 1 also demonstrates that mathematical relationships exist among the listed rheological parameters. For example, n and k values easily can be calculated from PV and YP for modeling purposes. This dispels the misconception that PV and YP cannot be associated with fluids that follow non-plastic flow behavior.

Table 1 - Initial and Optimized Properties (Maglione et al. 1999) with Calculated Parameters in Bottom 5 Rows

Parameter	Initial Values	Optimized Values
ρ (lb/gal)	16.0	16.0
n	0.66	0.4
k (Pa•s^n)	0.65	0.1
τ_y (Pa)	2.30	7.2
R_{600}	136.3	18.4
R_{300}	88.0	17.6
PV (cP)	48.3	0.8
YP (lb/100ft^2)	39.7	16.8
τ_y (lb/100ft^2)	4.8	15.0

Several other issues are related to the YP. For one, YP is an extrapolated value considered to be a flow property and should not be confused with the gel strength obtained after a period of no shear, which is a rest property. Negative YP values, such as those determined for some weighted lime muds, are mysteries. It has been suggested that the high solids loading could cause the mud to behave as a *dilatant* fluid (one whose viscosity increases with shear rate). Finally, YP also is different from the yield stress, a parameter associated with considerably more myths, misconceptions and mysteries.

Bottom Line: PV, YP, YS (or τ_y), and gel strengths are the best parameters for engineering drilling fluids. These data can be used to calculate other parameters, like n and k, for modeling purposes. The power-law n value also is a good indicator for polymer muds that behave pseudoplastically.

4. Gel Strengths – a rose by any other name?

Gel strengths measured on rotary viscometers are the only time-dependent properties routinely tested. They are used to characterize the reversible internal structure that develops while the fluid is at rest and subsequently breaks when the fluid is sheared. Gel structures have long been overlooked regarding their effects on drilling fluid rheology and hydraulics. Issues arise concerning the measurements themselves, their interpretation, and their impact on drilling operations. Labeling and typecasting also are a persistent source of confusion.

Gel strengths are indicators of overall fluid quality and suggest a fluid's ability to suspend cuttings, cavings, and weight material when drilling fluids are at rest. However, elevated values can cause wide pressure differences when fluid flow is initiated by pumping or tripping pipe. Excessive gelation can also impede efficient separation of undesirable solids at the surface.

Time-dependent materials whose viscosity decreases with time at a constant shear rate are known as *thixotropic*. Thixotropy arises from structure deformation caused by disruption of weak, intermolecular forces. *Thixotropy* should not be confused with *shear thinning*, which is a viscosity reduction with increasing shear rate. However, the rate of change in viscosity in both cases helps to describe the flow behavior of the fluid.

The industry-standard procedure (API 2005, 2009) is not a preferred method of measuring time dependency, but it is well-established, consistent, and generally useful. Gel strengths are peak V-G meter dial readings at 3 rpm after shearing the fluid at high speed and allowing it to rest for 10-sec and 10-min intervals. If the difference is high, measurement after 30 min may be in order, although this extra reading may be suspect if excessive gelation causes viscometer slip. Jacknik (2005) points out that the peak 3-rpm values represent the structural growth plus the shear stress at that shear rate, and uncoupling the two could improve understanding of the behavior. This is illustrated schematically in **Fig. 2**. The graph in **Fig. 3** shows thixotropic effects for a test contrasting gel-strength measurements at 3 and 6 rpm, but there was little difference in the two values in this example.

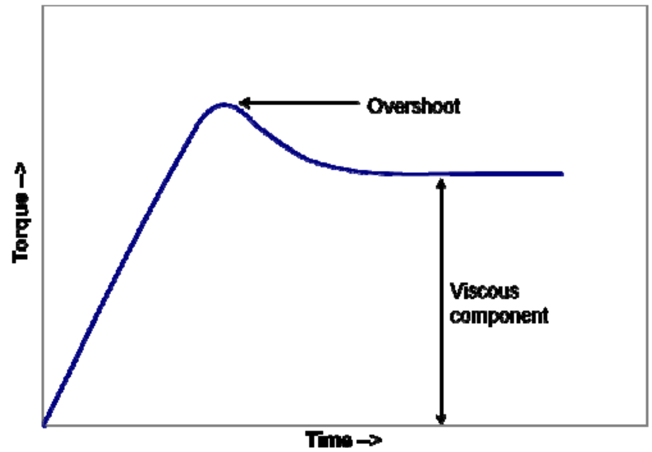

Fig. 2: Drawing showing peak and viscous components of a typical gel-strength test.

Temperature and pressure play significant roles, but gel strengths normally are measured in conjunction with and under the same conditions as the viscous properties. Unfortunately, they are mostly ignored during HTHP-viscometer testing because of time limitations. This makes it very challenging to model downhole values, especially if the drilling fluid is static in the wellbore for extended periods.

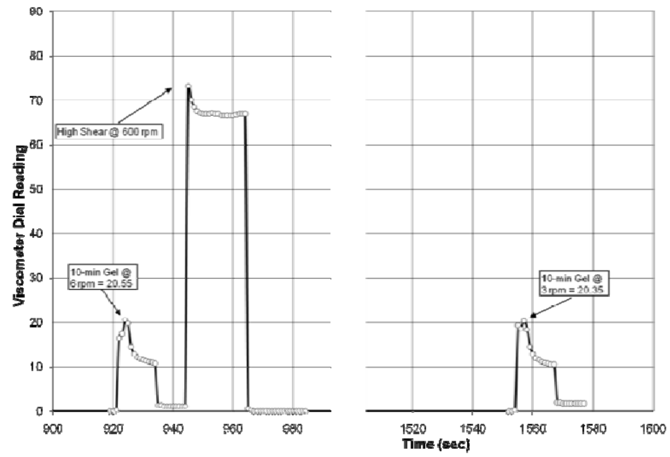

Fig. 3: Test comparing gel-strength measurements at 6 and 3 rpm showing thixotropic effects.

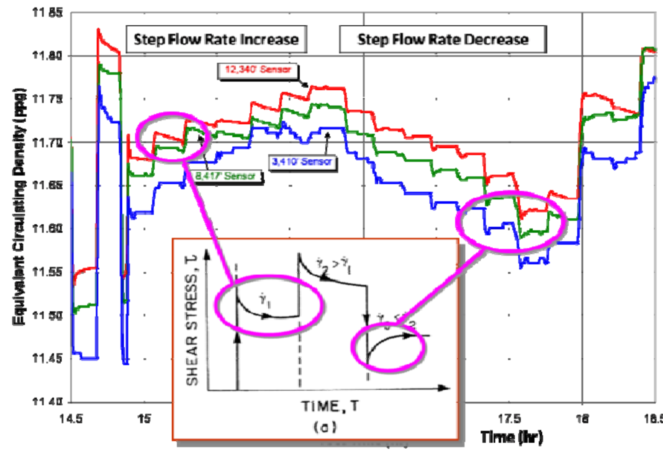

Fig. 4: Impact of flow rate step change on ECD from White et al. (1996) with superimposed Fig. 4.22a from Bourgoyne et al. (1986).

Gel strengths are qualified and labeled according to their magnitude and difference. The widely used term "progressive gels" denotes the undesirable case of a high 10-min gel compared to the 10-sec gel, usually associated with clay-based viscosifiers. However, other terms including "flash", "flat", and "fragile," are used interchangeably and have created considerable discussion and controversy. "Flash gels" best describe elevated-but-equal gel strengths usually associated with internal networks such as those rapidly formed by MMO fluids discussed earlier. Indeed, a myth that emanated from MMO-predecessor fluids is that the term "fragile gels" comes from elevated flash gels that break quickly and easily. However, "fragile gels" has been applied to multiple behaviors, such as what some would call "flat gels." As such, the true definition of "fragile gels" remains a mystery.

Overshoot in shear stress during gel-strength measurements is highly dependent on the time to reach 3 rpm viscometer speed, but fortunately the variance for oilfield viscometers is probably negligible. In drilling operations, however, consistency is lost, and both flow and pipe acceleration are especially critical. On most wells, for example, the highest and lowest pressures imposed on the formation are caused by pipe acceleration and deceleration.

However, overshoot can occur even if the fluid has not been at rest. **Fig. 4** includes data from White *et al.* (1996), where synthetic-based mud flow rate in an offshore well was step-wise increased and decreased. Note the comparison with the superimposed graph from Bourgoyne *et al.* (1986), who credit the response to thixotropy. Instead, Jacknick (2005) attributes this to significant increases in the Deborah number, which considers the fluid relaxation time and the time over which the stress is applied.

Bottom Line: API protocol for measuring gel strengths is not ideal, but data are still useful for monitoring development of a gel structure. Labeling and typecasting of gel-strength trends and magnitude have contributed to confusion with data interpretation. Standardization would be welcomed.

5. Yield Stress – myth or engineering reality?

Yield stress is perhaps the most controversial property in drilling fluid rheology for all those in the rheochain. Rheologists continue to debate its existence, all struggle with its measurement (Power and Zamora 2003, Maxey *et al.* 2008), chemists look for better ways to obtain it, and engineers sometimes embrace it as the key rheological parameter for hole cleaning, barite sag, and wellbore pressures.

Barnes and Walters (1985) wrote that yield stress is an ideal concept, one that does not exist in reality. Hartnett and Hu (1989) made the case for the yield stress as an engineering reality. Nguyen and Boger (1992) followed with "Despite the controversial concept of the yield stress as a true material property…there is generally acceptance of its practical usefulness in engineering design and operation of processes where handling and transport of industrial suspensions are involved".

In the drilling industry, yield stress is considered both an engineering reality and a material property. It sometimes is called the "true" yield stress, but only to distinguish it from the extrapolated yield point. Other times it is confusingly called the yield point. It remains, however, that it can be the static stress above which the fluid turns from a semi-solid state into a liquid one, or the dynamic stress where the fluid turns from a liquid state to a semi-solid one.

Yield-stress existence depends on the nature of the experiment being conducted to measure it. Zamora and Lord (1974) addressed yield-stress measurement with standard oilfield equipment. Because of the prevalence of 2-speed viscometers at that time, they chose the static-based "zero gel," a gel-strength measurement taken immediately after shearing the fluid. Power and Zamora (2003) later investigated six options. After encountering experimental difficulties similar to those recognized by others, they concluded that the most practical and consistent industry choice was the dynamic-based LSYP (low-shear yield point) based on R_6 and R_3, now in an API recommended practice (API 2006):

$$LSYP = 2R_3 - R_6 \qquad \text{(Eq. 2)}$$

Moeller *et al.* (2009) suggested that measurement problems are associated with failure to differentiate between thixotropic and simple, time-independent yield-stress fluids. In principle, the distinction is simple to make using common methodologies for measuring thixotropy. The problem is that, despite the microstructure that gives rise to both yield stress and thixotropy, the two phenomena are hardly ever considered together or reconciled. However, unification of low-shear-rate rheology and gel properties of drilling fluids has been successfully addressed by Herzhaft *et al.* (2006). They developed a relatively simple model to predict "unusual behavior for the drilling mud at very low shear rate like shear localization that could explain the difficulties associated with such measurements…and predict transient phenomena like pressure peak after restart."

Assuming that yield stress can be consistently measured, there are questions on the recommended value for optimum fluid performance. The magnitude is often linked to requirements for hole cleaning and barite sag discussed later. By definition using conventional models, however, yield stress is bounded by zero and the Bingham yield point. Based on a large number of API mud reports, Power and Zamora (2003) statistically determined that the ratio τ_y/YP for fluids as run in the field averaged 0.57, 0.5 and 0.3 for synthetic, oil, and water-based drilling fluids, respectively.

Bottom Line: Yield stress has attracted much attention for managing hydraulics issues, despite questions on its existence and controversies with its measurement. LSYP is a good choice for determining its value, but other techniques including curve fitting are equally acceptable.

6. Rheological Models – the right one to use?

Rheological models are constitutive equations that relate shear stress and shear rate. Drilling fluid models and their derived parameters are used for fluid development, treatment, and hydraulics calculations. However, there are issues related to selection of appropriate models, how they are matched to measured data, and how they are used for pressure-loss calculations.

Despite the rheological complexity of drilling fluids, models traditionally are based solely on viscous properties measured by industry-standard viscometers. Only three have achieved notable traction with drilling fluids. The Herschel-Bulkley (modified power law), which is the current API recommendation, includes the power law and Bingham-plastic model as special cases. Required parameters are calculated from τ_y and R_{600} and R_{300} (or PV and YP) values as specified by API (2006).

Measured data determine the model to use (not the reverse), so it is inappropriate to select the model to simply match real or expected field results. For shear-stress/shear-rate or dial-reading/sleeve-speed viscometer data, each model is linear on a given coordinate system: Bingham-plastic model on rectangular coordinates; power law on logarithmic coordinates; and modified power law (with τ_y subtracted from dial readings) on logarithmic coordinates. For consistency, each curve fit should preserve R_{600} and R_{300} values.

Familiar constitutive models cannot be used directly for pressure-loss calculations. They must be converted to flow equations based on the shear stress (τ_w) at the wall where friction is greatest. This involves complex mathematical manipulations. Unfortunately, closed-form solutions are available only for the power law, although special mathematical techniques have been developed to solve flow equations for the other two models.

Zamora and Power (2002) presented an empirically derived flow equation expressed in a form easily recognized by field engineers and sufficiently accurate for most high-end software applications. The intent was to unify the wide range of industry personnel concerned with rheology and hydraulics. The flow equation subsequently was adopted in an API recommended practice (API 2006). It replaced a dual-segment power law that was mathematically sound and accurate for hydraulics calculations. It did not include a yield stress that has gained importance, however, and the two sets of n and k parameters were confusing to field personnel.

Fig. 5 illustrates annular flow curves for the three rheological models defined by τ_y/YP = 0 for the power law and τ_y/YP = 1 for the Bingham-plastic model. The top line represents the simplified Bingham-plastic model, on which most pressure-loss calculations for that model are based. It is higher than the exact solution at the lower shear rates and its intercept of 15 is 3/2 times the yield point of 10. For pipe flow, it would be 4/3 times the yield point.

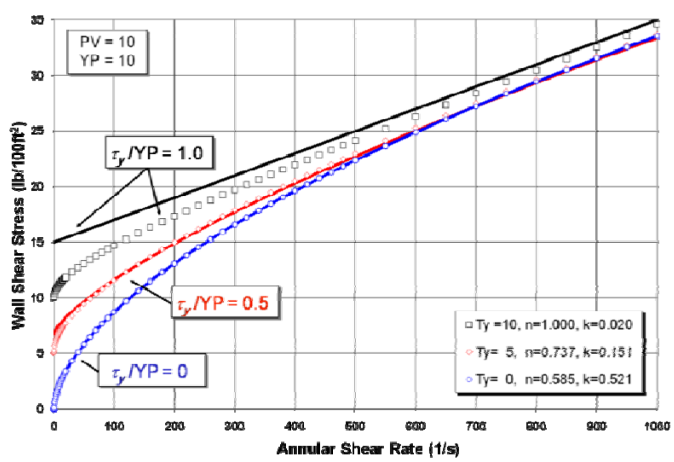

Fig. 5: Annular flow curves comparing exact (markers) and approximate (solid lines) solutions for different R ratios (Zamora and Power 2002).

Bottom Line: The Herschel-Bulkley (modified power law) is currently the recommended rheological model of choice for drilling fluids. It includes other traditional models as special cases. Three parameters are required, all of which are useful independently for drilling fluids engineering. The flow equation is still needed for pressure-loss calculations, but an empirically derived expression simplifies its use by engineers and software developers.

7. Flow Rate and Flow Regimes – all in the details?

Flow rate is always a conundrum in drilling. In one sense, it can be challenging to find the optimum flow rate that cleans the hole, mitigates barite sag, delivers maximum hydraulic energy to the bit, and avoids excessive annular pressures that could cause lost circulation. In another sense, it causes fluids to move among different flow regimes that are deceptively complicated and impact pressure losses in unusual ways.

Pressure relationships in different segments of the circulating system are exponentially proportional to flow rate (Q). These are Q^n in the annulus (laminar flow), Q^2 through bit nozzles, and Q^s inside the drill string (turbulence), where the exponent s is the turbulent flow behavior index.

Some question if streamline laminar flow can ever obtained in the downhole annulus. It certainly is difficult in laboratory flow loops, where a sufficient length-to-diameter ratio must be available to ensure streamline flow. Considering geometrical interruptions in the annulus even in vertical wells, it is easy to imagine how eddy currents can occur throughout.

Eccentric annular flow complicates matters. Concerning just flow regimes at increasing flow rates, turbulence will be achieved in the wide section of the annulus long before the narrow section. Famed rheologist Arthur Metzner once suggested in a private discussion that flow in the wide side of an eccentric annulus could depart from laminar flow at generalized Reynolds numbers as low as 1,600, while turbulence all around might require Reynolds numbers above 10,000. He also said that generalized Reynolds numbers for annuli should always be calculated based on concentric geometry.

Assuming incompressible flow, pressure losses through jet nozzles (a) depend on change in kinetic energy caused by fluid acceleration, (b) are proportional to density, and (c) are independent of fluid viscosity. However, industry laboratory and field studies (Beck *et al.* 1995) have shown relationships between penetration rate and kinematic viscosity at bit conditions. This suggests that both pressure loss and rheology must be considered for true optimum bit hydraulics. [On a side note, API (2006) found sufficient evidence to increase the discharge coefficient from the traditional value of 0.95 to 0.98, although some suggest it should even be as high as 1.03.]

Flow inside the drill string is nearly always turbulent. However, there are many unknowns that complicate simulations. Because of the absence of turbulent friction-factor data on Herschel-Bulkley fluids, industry has defaulted to those developed for power-law fluids (API 2006). To further complicate matters, White *et al.* (1996) measured a 1.98 turbulent flow index in the drill string, significant because it exceeded the expected 1.7 to 1.8 range. Investigation of the effects of restricted-ID tool joints by Denison (1978) points to the impact of entry and exit losses. While corrections for these effects increase pressure losses, they do not alter the turbulent flow s exponent. Perhaps extensional viscosity plays a role here; but for now, turbulent flow inside drill string, for the most part, remains a bit of a mystery.

Another turbulent-flow effect is manifested when newly-mixed polymer drilling fluids are circulated into a well. Unusually low pump pressures, which suggest a drill-string washout, are attributable to polymer *drag reduction* that can reduce frictional pressure loss in turbulent flow by as much as 80%. Unfortunately, this benefit systematically disappears as drill solids are incorporated and polymers shear degrade.

Bottom Line: The relationship between frictional pressure and flow rate depends highly on the flow regime, which can be difficult to determine. Turbulent flow, in general, is mysterious and further investigation is in order.

8. Hole Cleaning – a matter of direction?

Hole cleaning has always been an important drilling issue, but directional and horizontal drilling have elevated problems and concerns to levels not experienced previously. In times past, hole-cleaning guidelines in vertical wells consisted of maintaining yield points numerically above the density (in lb/gal) and annular velocities greater than 100 ft/min. For directional wells, best practices involving fluid rheology, drilling operations, and remedial procedures evolved based on different areas and well types. Unfortunately, these practices may not be interchangeable, giving rise to rheology-related, continually-asked questions - “thick or thin?”, “turbulent or laminar?”, “viscous or weighted sweeps?”, “how fast to rotate the drill string,” and even “what does ‘good’ hole cleaning mean, anyway?”

At one time there were myths that rheology and pipe rotation did not play roles in horizontal wells and that turbulent flow was required for proper hole cleaning. This was understandable, since these myths were based on drilling with brine in the Austin chalk formation, a very high percentage of the horizontal wells drilled at that time. These practices did not transfer well to large-diameter, directional wellbores in less-forgiving formations.

Drilling horizontal wells in Alaska took a different approach (Beck *et al.* 1993). Viscoelastic, biopolymer reservoir drilling fluids still in use provide excellent carrying capacity and suspension in laminar flow. These fluids provide high viscosity at low shear rates. In support of these wells, videos taken in laboratory flow loops (Zamora and Jefferson 1993) visually showed the impact and interrelationships among relevant drilling parameters, differences between rheology and viscosity, and the elastic rebound of biopolymer fluids. Without assurance that lab tests truly reflected downhole behavior, at least the testing validated the field practice of maintaining a specific viscosity as measured with a non-standard viscometer at very low shear rates.

Yield stress has become a key parameter for hole cleaning and barite sag, discussed in the next section. Some choose to run τ_y at a magnitude equal to or just larger than the hole size in inches, a myth that probably originated with the flow-loop tests just described. Unfortunately, there is a misconception that hole-cleaning and sag problems can be solved by simply obtaining the right yield-stress values, with less emphasis on drilling practices. Regardless, there is ample evidence of an upper limit (around 16-17 lb/100ft^2) above which higher values can be counterproductive.

Saasen and Loklingholm (2002) subsequently challenged industry thinking by focusing on cuttings-bed characteristics, concluding that the drilling-fluid gel formed in the bed was the primary cause of hole-cleaning problems. Instead of using rheological properties to prevent bed formation, they pointed to the benefits of using low-viscosity, low-gel-strength fluids that could more easily remove beds that surely would form anyway. High-molecular-weight polymers would only be used to prevent barite sag, of course, intimating that these polymers would, in fact, help the sag issue.

Pipe rotation can provide dual benefits of minimizing bed formation and mechanically assisting with bed removal. Best efficiency is obtained when the pipe is eccentric on the low side, the drilling fluid is sufficient to carry cuttings into the main flow stream, and rotary speed is above around 100 rpm.

Sweeps are used remedially for removing cuttings beds. Viscous sweeps seem to work well in vertical wells, but less so in directional wells because they tend to flow along the wide, upper side of the hole rather than where they might do the most good. More success has been achieved with weighted sweeps in directional and horizontal wells. The idea of using a combination of a "thin" pill to stir the cuttings followed a "thick" pill for transport has been used for years, but its validity is still a mystery. In all cases, pipe rotation is a great help.

Sometimes, wellbore instabilities manifest themselves as hole-cleaning problems. While poor hole cleaning may be the symptom, increasing mud weight to stabilize the wellbore instead of altering drilling fluid rheology can be the cure.

Finally, there is no consensus on the definition of "good" hole cleaning. Hole-cleaning efficiency is difficult to measure and most numerical models are often idealistic. For example, most hydraulics programs use an input cuttings size for every single cutting generated by the bit, and assume that their size does not change on the tortuous trip to the surface. Some use cuttings slip velocity and cuttings concentration in vertical wells and cuttings bed thickness in directional wells as indicators. Others use fuzzy logic descriptors ("excellent", "good", "poor", etc.) that make sense to field personnel but do not transfer well into spreadsheets that require a number. API (2006) includes useful hole-cleaning charts, but without the models that could help software developers. Cuttings flow (or flux) meters are now available to help quantify the volume of cuttings reaching the surface, but results are mostly relative and mass-balance modeling can be a real benefit.

Perhaps the definition of "good" hole cleaning should be based on the extent of well problems attributable to hole cleaning. Cuttings beds form in most directional wells. Extraordinary efforts to totally remove them may not be necessary. It may be sufficient to clean just enough to prevent hole cleaning problems.

Bottom Line: Rheology plays a major role in hole-cleaning efficiency, but it must be augmented by proper drilling practices. Best strategies are based on specific well requirements. Lacking a good measurement, hole cleaning efficiency can be based on the severity of well problems associated with hole cleaning.

9. Barite Sag – is there a "magic bullet"?

Barite sag is perhaps the most "mysterious" of the hole problems related to rheology and hydraulics. It is the excessive deposition of moveable weight-material beds in a directional well. It is recognized by a density variation greater than 0.5 lb/gal between the <u>maximum</u> and <u>nominal</u> mud densities while circulating fluid out of the well. While there is now a consensus on causes and best practices of barite sag, researchers continue to look at mud types, formulations, special additives, and rheology for answers. Moreover, industry seemingly continues to seek a rheological "magic bullet" that, on its own, can mitigate and even prevent barite sag. This perhaps could be counterproductive, since barite sag is not just a mud rheology problem.

Originally thought to be a static settling problem, barite sag is now accepted to be primarily a dynamic settling problem aggravated by static settling, bed slumping towards the bottom of the well, and extraordinarily complex flow patterns downhole. Gel strengths, R_6 and R_3 values, yield stress, PV/YP ratios, viscosity windows, and viscoelasticity are among those parameters that have been investigated over the years to address this complex physical behavior. Among these, the yield stress, using guidelines similar to those for hole cleaning, seems to be the most widely used. To complicate this further, there currently are no sound, scientific methods or protocols with long-established precedent for measuring sag potential.

Saasen *et al.* (1995) and Tehrani *et al.* (2004) are among those believing that viscoelasticity may be a key element, especially since virtually every other avenue has been investigated. Indeed, Saasen *et al.* (1995) succinctly summarize, in the abstract of their paper, the potential for viscoelasticity to assist with barite sag as well as the key issues that could hinder its application.

Bottom Line: Barite sag is a complex issue. Despite the importance of rheology, questions persist on which rheological properties are best suited to mitigate the problem. Perhaps the most serious misconception is that the "magic bullet" already exists in one of the parameters routinely measured, and that drilling practices are of lesser consequence.

10. ECD – easing through narrow windows?

Equivalent circulating density, the density equivalent of the hydrostatic plus pressures resulting from fluid flow, plays a significant role in drilling operations. ECDs are particularly critical when drilling wells with narrow operating windows. Annular fluid flow is created by pumping, pipe movement, and drillstring rotation, each of which adds frictional pressures. However, results can be counterintuitive. For example, pumping provides the highest flow rates but may not impose the highest pressures on the wellbore. Swab pressures can result while tripping <u>in the hole</u>, and surge pressures are possible while tripping <u>out of the hole</u>. Pipe rotation nearly always increases annular pressures in the field, but there are conditions where laboratory tests show the opposite. Accurate modeling is essential; but networking all the right elements is daunting, especially in the presence of uncertainties.

The challenge is to minimize ECDs by achieving balance among the drilling fluid rheology, flow rates, and the other interrelated factors required for successful drilling operations. Generally speaking, however, changes in these individual factors that could improve hole conditions and drilling efficiency usually result in higher ECDs.

Highest wellbore pressures appear as pressure spikes from breaking circulation and pipe movement during connections, tripping, and running casing. Gel structure is important when breaking circulation, but the rate at which stress is applied (acceleration and deceleration) is particularly critical. It is for this reason that pressure surges while tripping pipe or running casing in the hole generally provide the largest pressure spikes. These usually occur during acceleration periods, so limiting average velocity to a certain speed may be inadequate for minimizing problems. Deceleration also is important, since stopping too quickly can result in swab pressures while tripping in the hole, and surge pressures while tripping out of the hole.

The myth that pipe rotation always increases annular pressures was verified by Hemphill *et al.* (2007) using annular-pressure-while-drilling measurements. Laboratory studies generally show that with increasing rotation, annular pressures first decrease and then increase at higher speeds (McCann *et al.* 1995). This has been more evident in highly shear-thinning fluids. The reasons that field observations and measurements always show pressure increases with rotation are not well known, so this remains a mystery for the time being.

ECDs are probably of most concern in deepwater drilling, where exposure to cold seawater temperatures can significantly increase rheology. Drilling in ultra-deepwater is more problematic, because of the extended time that the drilling fluid is exposed to low temperatures and the comparatively lower fracture gradients.

Modelers and software developers charged with simulating downhole behavior in the annulus as well as the entire circulating system, especially in real-time environments (Zamora *et al.* 2000), must contend with a wide range of issues. Their products are essential for planning, problem solving, design, and optimization. Overall, the industry has done very well, despite the uncertainties, complex flow behaviors, various transients, inadequate measurements, poor data quality, and incomplete information.

Bottom Line: ECD management is critical for all wells, especially those drilled through narrow operating windows. Extreme downhole pressures and high/low temperatures can be especially problematic. Unfortunately, proper management is not a trivial exercise and truly involves coordination among all those in the rheochain.

Summary

Many of the myths, misconceptions and mysteries in rheology and hydraulics originate from the inhospitable drilling environments downhole and on the rig. Darley and Gray (1988) summarized it well: "[mud] tests at the wellsite must be performed quickly and with simple apparatus…but only approximately reflect downhole behavior. Nevertheless, these tests serve their purpose very well if their limitations are understood and if the data obtained from them are correlated with experience."

The extreme downhole environment can be of greater concern. Fluid chemistry can change irreversibly. Extreme HTHP viscometers are now testing to 600°F and >30,000 psi. Moreover, nothing is steady state, nothing is known for sure, and much is unexpected.

Finally, the information that comes down the rheochain eventually must be reviewed and applied by some who will compare the results against expectations based on their own myths, misconceptions, and mysteries of rheology and hydraulics.

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Nomenclature

HTHP	= high temperature/high pressure
k	= laminar flow consistency factor, lb·s^n/100 ft^2
LSYP	= low-shear yield point, lb/100 ft^2
MMO	= mixed-metal oxide bentonite extender
n	= laminar flow behavior index
PV	= plastic viscosity, cP
R	= parameter ratio τ_y/YP
R_3	= viscometer reading at 3 rpm, ~lb/100 ft^2
R_6	= viscometer reading at 6 rpm, ~lb/100 ft^2
R_{300}	= viscometer reading at 300 rpm, ~lb/100 ft^2
R_{600}	= viscometer reading at 600 rpm, ~lb/100 ft^2
s	= turbulent flow behavior index
t	= funnel time, s/qt
V-G	= viscosity-gel as in V-G meter
YP	= yield point, lb/100 ft^2
YS and τ_y	= yield stress, lb/100 ft^2
μ_e	= funnel equivalent viscosity, cP
ρ	= fluid density, s.g.
τ	= shear stress, lb/100 ft^2
τ_w	= wall yield stress, lb/100 ft^2

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