Drilling Geomechanics – Pre-Drill Fracture Centroid Perspective Is Key To Spot Casing Setting Depths and Trajectories At High Risk For Ballooning.

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Abstract
Drilling geomechanics offers perspectives on issues we face in drilling and constructing wellbores that are helpful in preparing plans that successfully model actual downhole conditions prior to drilling in. Several particular issues have been inadequately addressed and commonly deemed to be unpredictable by industry experts. These particular events, specifically loss/gain phenomena, and the ability to predict and explain various nuances have not been adequately explained in the world of geomechanics. Since the statistics kept by well control companies show that wrong assumptions on loss/gain events and otherwise misinterpreting or miscommunicating well control events account for a great percentage of resulting blowouts, the importance of this topic is clear. The procedures for dealing with these issues are better discussed in full prior to spudding the well, yet up until now there were no methods for predicting ballooning in advance. Drilling margins in wells being very small, misdiagnosis can lead to unnecessary well control procedures that can be very costly and lead to many hours of non-productive time (NPT). Even worse are instances in which a real kick is misdiagnosed as ballooning and the well is allowed to flowback leading to an increase in kick volume and shut-in pressures.

For years it has been observed that drilling in and around certain conditions one can expect ballooning. In hindsight the particular situations can be seen and a paradigm created. Within this paradigm it can be seen that, for particular in-situ stresses, magnitudes, structures, and localized peculiarities, patterns emerge that might suggest a predictable set of circumstances that lead to ballooning. The most vital element of predicting ballooning issues in the pre-drill planning phase is to utilize seismically identifiable stress features such as faults, folds and bright spots to imply stress magnitudes and directions. This is in essence deriving present stress information from past strain seismically recorded as deformation from reflected seismic interpretation packages. The significance of such structures and stresses that are clearly indicated in seismic records are vital to the methods outlined by this paper.

This paper addresses the issue of ballooning in drilling and gives a geomechanical explanation and means for predicting and mitigating the issues that will be confronted during the drilling phase of well construction wherever possible. It is my belief that in doing so communicating in interdisciplinary teams and conveying issues and instructions between the rig and the office will be greatly enhanced. The result should save time in diagnosing the problems and in implementing the solutions and also result in much safer operations.

In most cases ballooning can be predicted for any trajectory and casing setting depth design using the concept of the “Fracture Centroid” (FC) (Davis 2011c) and an alternative trajectory and/or casing setting depth designed that will avoid the worst conditions or eliminate the ballooning entirely. If this is concept is used and proven to prevent wellbores with extremely high risk of ballooning, these screening and design methods will be responsible for eliminating one of the most, if not the most significant, causes of well control incidents and NPT in the industry.

Introduction

The phenomenon of "ballooning", "breathing", "loss/gain" or "wellbore storage", will heretofore be simply referred to as "ballooning". With acknowledgement to all previous documented arguments to this being a misnomer and also the fact that more often than not, people on the rig and in the office do speak of this phenomena as "ballooning". Complicating factors being observed in the field are: losses with incomplete flowback, complete losses and no flowback, losses and flowback during trips and not during connections, losses and flowbacks exceeding losses, losses of mud and flowbacks of gas, etc. The list is seemingly endless yet I will construct a matrix and list explanations and layman's terms of many of the most commonly experienced phenomenon below.

First, let's examine a scenario common to many of the most common petroleum traps drilled today that can and will balloon if penetrated. Most instances can be predicted and avoided by diligent scrutiny as to the structure, the pressure compartments and imbalances that can be quickly and easily deduced. Both pressures and stresses in the sands and shales that are involved in a ballooning wellbore can be surmised with the clever use of seismically obtainable information. As stated earlier it is possible to detect wellbores that will balloon before drilling by using seismically attainable data and therefore it is possible to avoid these scenarios even in wildcat wellbores. The content of the reservoir fluids is vital to the analysis and the prediction of sand contents isn't always guaranteed as we all know. Even if reservoir contents can't be absolutely ascertained a screening for possible ballooning conditions based on a worst and best case can easily be made.

Structural apex penetrations of strata with sand/shale sequences where the sand pore pressures are much higher than the bounding shale pore pressures have a high potential to balloon. This same environment tends to have sand fracture strengths exceeding the shale fracture strength by an appreciable amount. The drilling fluid equivalent static density (ESD) will necessarily be higher than the highest exposed sand reservoir pressure or else the well will kick during connections. The only remaining factor needed for ballooning is a sealing boundary that prevents fractures that form in the shales from extending indefinitely allowing the fracturing fluid to leak off. The amount of pressure by which the shale fracture pressure exceeds the highest exposed sand pore pressure is the margin that a drilling operation must work between. Let's call this the ballooning threshold (BT):

$$\text{BT} = P_{f_{min_{shale}}} - P_{p_{max_{sand}}} \text{……………………..(1)}$$

The overbalance margin of the drilling mud over the highest sand pore pressure, the equivalent circulating density (ECD) with the rig pumping at full rate and equivalent annular density once drilling at full rate of penetration (ROP) begins will determine if the wellbore balloons.

Complications of Ballooning Phenomena

A quick matrix of the most commonly experienced ballooning phenomena and the relations that determine these follows. For all of the following relations it is assumed that the wellbore penetrates the strata in an above FC position so:

$$P_{f_{min_{shale}}} \leq P_{f_{min_{sand}}}$$
$$P_{f_{min_{shale}}} \geq \text{ESD} \geq P_{p_{max_{sand}}}$$

and therefore the well will not kick as long as there is no swab pressure applied and the well will not lose mud unless there is a surge pressure applied. This is by definition the conditions as they exist in a ballooning wellbore environment. The matrix is:

No losses with pumps off:

$$\text{ESD} - P_{p_{max_{sand}}} \leq BT \leq P_{f_{min_{sand}}} - P_{p_{max_{sand}}}$$
$$\text{ESD} \leq P_{f_{min_{shale}}} \leq P_{f_{min_{sand}}}$$

Losses as pumprate is increased before full circulation rate reached with incomplete flowback (partial ballooning):

$$P_{f_{min_{sand}}} - P_{p_{max_{sand}}} \leq \text{BT} \leq \text{ECD} - P_{p_{max_{sand}}}$$
$$\text{ECD} \geq P_{f_{min_{sand}}} \geq P_{f_{min_{shale}}}$$

Losses as pumprate is increased before full circulation rate reached. Full volume lost is returned during connections or when pumps stopped (ballooning):

$$P_{f_{min_{sand}}} - P_{p_{max_{sand}}} \geq \text{ECD} - P_{p_{max_{sand}}} \geq \text{BT}$$
$$P_{f_{min_{sand}}} \geq \text{ECD} \geq P_{f_{min_{shale}}}$$

Losses only after full circulation rate and drilling begins with incomplete flowback (drilling with partial ballooning):

$$\text{BT} \leq P_{f_{min_{sand}}} - P_{p_{max_{sand}}} \leq \text{EAD} - P_{p_{max_{sand}}}$$
$$\text{EAD} \geq P_{f_{min_{sand}}} \geq P_{f_{min_{shale}}} \geq \text{ECD}$$

Losses only after full circulation rate and drilling begins with complete flowback (drilling with ballooning):

$$P_{f_{min_{sand}}} - P_{p_{max_{sand}}} \geq \text{EAD} - P_{p_{max_{sand}}} \geq \text{BT}$$
$$P_{f_{min_{sand}}} \geq \text{EAD} \geq P_{f_{min_{shale}}} \geq \text{ECD}$$

Losses only after full circulation rate and drilling begins with total losses at full ROP and incomplete flowback (control drilling with ballooning):

$$\text{EAD} - P_{p_{max_{sand}}} \geq \text{BT} \geq P_{f_{min_{sand}}} - P_{p_{max_{sand}}}$$
$$\text{EAD} \geq P_{f_{min_{sand}}} \geq EAD_{reduced\ ROP} \geq P_{f_{min_{shale}}} \geq \text{ECD}$$

There are other fine nuances of scenarios not described in this matrix and yet this probably covers the most commonly found. Another common scenario that happens is that the ESD is increased due to increasing signs of a decreased margin until, during circulating around the increase, partial returns are lost. The circulation rate is reduced and yet once the higher density mud is completely circulated around the wellbore is losing mud slowly. Upon tripping out of the hole and reducing the ESD by the swab pressure of pulling the drillstring from bottom, the well is ballooning back mud. This is very dangerous and needs to be understood. The matrix relations follow:

$$P_{f_{min_{sand}}} \leq \text{EAD} \leq \text{ECD} \leq P_{f_{min_{shale}}} \leq ESD$$
$$P_{f_{min_{shale}}} \geq ESD - \Delta P_{swab} \geq P_{p_{max_{sand}}}$$

This scenario is not dangerous unless:

$$ESD - \Delta P_{swab} \leq P_{p_{max_{sand}}}$$

The problem is if there is mud ballooning back during a trip out of the hole it is necessary and yet obvious to determine which of the following is true:

A kick is being swabbed into the wellbore:

$$ESD - \Delta P_{swab} \leq P_{p_{max_{sand}}}$$

The wellbore is ballooning:

$$P_{f_{min_{shale}}} \geq ESD - \Delta P_{swab} \geq P_{p_{max_{sand}}}$$

Another quick note is to warn that sometimes a shale will balloon immediately below a sand. Once wellbore pressures are brought back below the shale fracture pressure the shale fracture closes and yet pushes the fluid at the boundary of the sand above it with enough pressure to cause the gas in the sand to be forced into the wellbore. Of course then the gas expands upon nearing the surface and it seems to be a real kick and yet once the balloon relieves its pressure and the gas clears the floor the well is dead. This is difficult to understand as it is happening and yet if you have the kind of understanding and knowledge that we are discussing in this paper you will be better equipped to notice such nuances and distinguish between ballooning and actual well control events better.

The anatomy of a ballooning wellbore

How much volume will be stored in fractures, how much, if any will be lost? How much will be returned to the wellbore and what the shut in casing pressure will be if the rig crew shuts the well in? This all can easily be determined pre-drill using the details of the information discussed in the previous section. Many times crews shut-in the ballooning wellbore confusing it with a possible kick. Pressure While Drilling (PWD) tools can be analyzed and a ballooning wellbore (Zoback 2007) diagnosed quickly by noting a gradual decrease in pressure when pumping is stopped and a corresponding gradual increase in pressure when pumping resumes. Of course without a PWD an experienced rig crew might, know or be instructed to, let a wellbore suspected of ballooning flow back into a 5 gallon bucket and note the time it takes to fill and then determine it is a balloon if the time gradually increases. All of the details of how to handle and analyze surface indications of ballooning will not be discussed further here although it is a worthy subject for discussion. The discussion below will focus on the geomechanical explanations and pre-drill methods to spot and avoid the worst subsurface positions for encountering these dangerous phenomena.

All of these details can be predicted with the knowledge and understanding of geological structures and resultant stresses, seismically attained material properties, formation water and petroleum fluid hydraulics, and the ESD, ECD, EAD, and swab/surges of the fluid circulation systems on the drilling rig. Geomechanical principles along with the concept of FC explain the phenomena of a ballooning wellbore.

Through experience drilling in areas that balloon I have come to understand that ballooning is symptomatic of shales that fracture and yet can't "absorb" the drilling fluids because the shales are porous yet not so permeable below a certain depth. Normal losses where the sands and shales or only the sands fracture, are different because the fluid entering the sands becomes trapped in the high porosity and permeability and the fluids are "absorbed" into the sand porosity once the fracture closes as wellbore pressure is reduced.

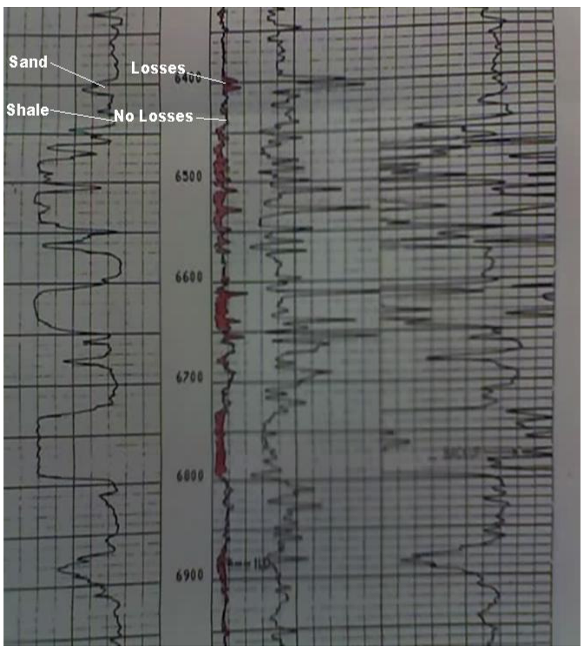

Figure 1—Log section showing indications of "normal" losses of drilling mud in sands.

This is distinct from the ballooning scenario where the fluid is not "absorbed" and is forced back into the wellbore as the fracture wedge closes and the fluid has no place to go except to return to the wellbore from where it came. The relation for this non-ballooning section is:

$$P_{f_{min_{shale}}} \geq P_{f_{min_{sand}}}$$

This wellbore section is by definition below the FC.

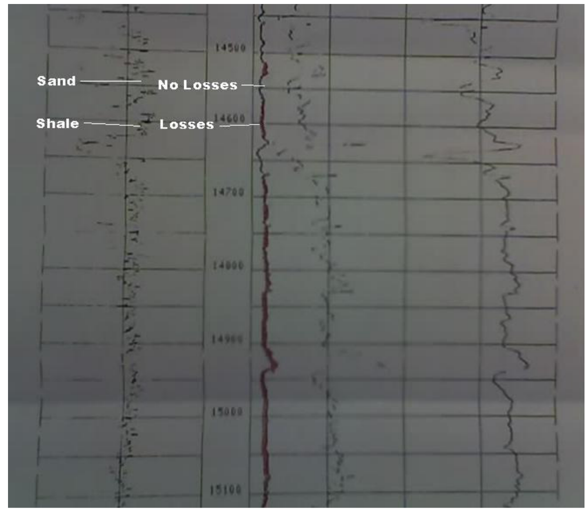

Figure 2—Log section showing indications of "ballooning" of drilling mud in shales

The task of this paper is to predict where these conditions exist in the earliest stages of a project so that wellbore trajectories that will drill in ballooning conditions can be avoided or in cases where they can't, be drilled with tactics, strategies and plans that will not result in substantial lost time nor unacceptable risks.

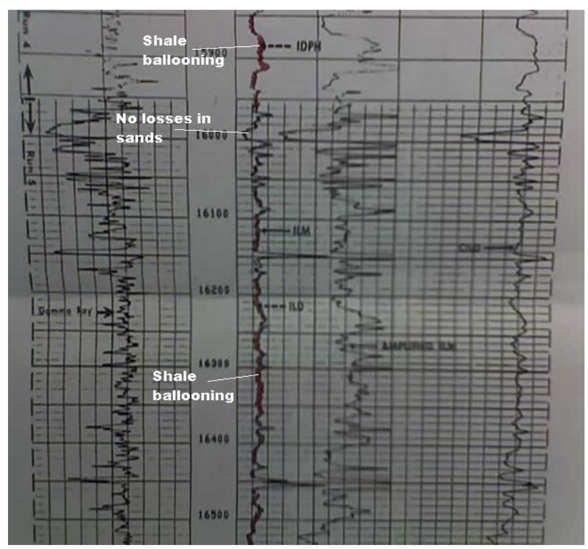

Figure 3—Another example of ballooning shales

The relation for these ballooning sections is:

$$P_{f_{min_{shale}}} \leq P_{f_{min_{sand}}}$$

This wellbore section is by definition above the FC.

Where do ballooning formations exist and why?

As introduced before wellbores drilled through highly dipping formations encounter high pressure sands bounded by shales of lower pore pressure at the above centroid apex of the structure because of sand pressure buoyancy effects.

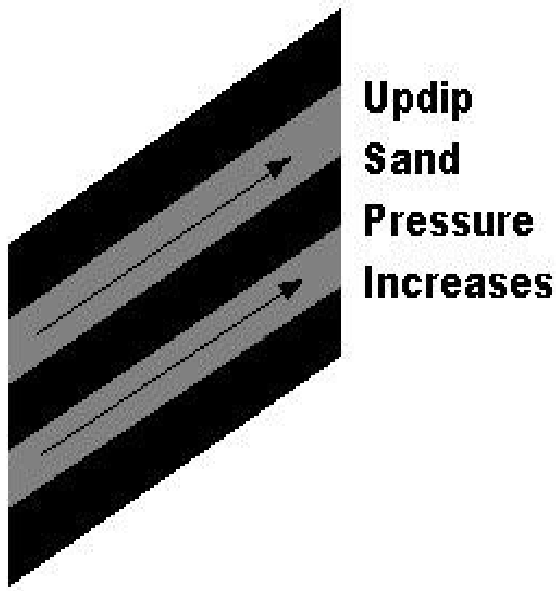

Figure 4—Bouyancy effect resulting in high updip sand pressures.

The pressure imbalances can be explained by the centroid effect that has been well documented in the literature and most recently by Heppard and Traugott (Heppard 1998). Sand pressure, in the above pressure centroid (PC) sections of a contiguous sand, is of higher pressure than the bounding shales. The above PC sands are of higher pressure than the bounding shales and increasingly so as the height above the PC increases. The increased fracture gradient in these sands is the result of increased pressure due to the structure of the sand/shale sequence, its resultant structural and poroelastic stress disequilibrium, and its elastic properties. The FC was discussed in depth in a previous paper (Davis 2011c). It was discussed that above the FC the sand fracture strength is higher than the bounding shales. In certain situations the sand fracture pressure will be so high as to completely deny a shale fracturing drilling fluid any exit from the fractured shale other than to return mostly back into the wellbore and thus balloon. There is another factor that further increases sand fracture pressures relative to the fracture pressures of the bounding shales. This is the reinforcing and increasing of the minimum principal stress in the sand relative to that of the shale in these above centroid geologic structure positions. The cause can be simply illustrated by analogy. Consider the sands as being stiff like steel plates and the shales "rubbery" as rubber plates. If the plates are horizontal:

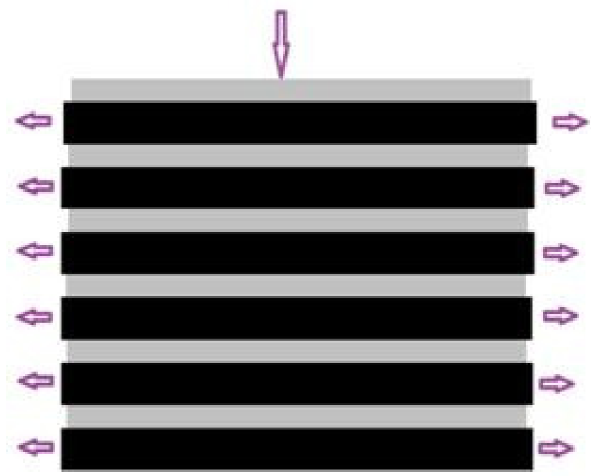

Figure 5—Sands and shales have different elastic properties and thus different effective stress.

Because of overburden and the Poisson's Ratio (ν) of formations, a vertical load is translated into horizontal stresses. Because the ν of zones is a function of composition and sands typically have lower values than shales the shales typically have higher fracture strengths than sands as a function of depth according to "bi-lateral constraint" theories used in the past. The Tri-Lateral Compaction (TLC) theory explained in an earlier paper (Davis 2011a) rejects the "bi-lateral constraint" methods of fracture gradient prediction because of its failure to correctly model increasing fractures strengths seen in deeper wells. The TLC theory corrects for this by acknowledging that there is a general strain as a function of depth model and this strain has a more severe effect on zones with highest Young's Modulus (E). This is seen by inspection of the basic TLC equation in a relaxed basin:

$$S_h = \frac{\nu}{1-\nu}\left(S_v - \propto P_p\right) + \propto P_p + \frac{E\nu}{1-\nu^2}\frac{(D_i - D_{\sigma_{v max}})}{(R_{\oplus} - D_{\sigma_{v max}})} + \frac{E}{1-\nu^2}\frac{(D_i - D_{\sigma_{v \max}})}{(R_{\oplus} - D_{\sigma_{v max}})} \ldots.(2)$$

An increased effective stress in the sands of a highly dipping reservoir scenario is due to the load of overburden being increasingly supported by the more rigid sands (higher E). The sands act like columns supporting the overburden load from acting on the shales. This scenario though extreme is often seen in modern petroleum traps, especially those of salt trapped flank sands of deepwater, extensional basins around the world. Because of the load being increasingly supported by the sands, the effective stress in the shales is further diminished causing the fracture gradients in the shales to decrease relative to the sands. This is a simplistic argument and yet it holds up under a more rigorous and detailed inspection. Of course the reality is that the sands and shales are rarely vertical yet explained by the principles of statics, the stresses and fracture pressures of the sands go up to a maximum at vertical and the stresses and fracture pressures, in the shales go down to a minimum. Of course this is in addition to the increase in sand/shale fracture ratio seen due to TLC strain of **equation 2**.

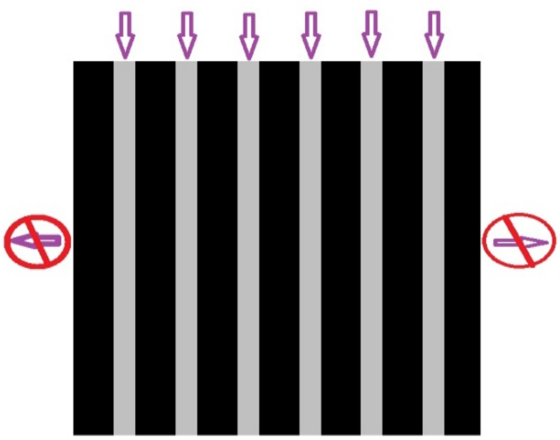

Figure 6—Tilted sands act as support columns effectively changing in-situ stress states.

Stress is increased in the sands relative to the shales, as they tilt toward 90°, because the sands being more rigid they take more of the load away from the shales. The stress states of the sands and shales as a function of the structural geometries are complex and it is not the task of this paper to go into the depths of these complexities. The point of this illustration and this paper is to know that in the case of tilted reservoirs, the conditions for ballooning exist from a pressure and stress condition found in the above centroid wellbore positions. From the example it is clear that highly dipping beds tend to increase sand fracture strengths relative to the bounding shales. The following discussion will demonstrate how to accurately model the stresses in these scenarios.

The use of dip angles to compensate for these effects is possible due to a general knowledge of strain in the horizontal plane and was introduced in the TLC equation (Davis 2011a):

$$\mathrm{S}_h = \frac{\nu}{1-\nu}\left(\mathrm{S}_v - \propto P_p\right) + \propto P_p + \frac{E\nu}{1-\nu^2}\,\frac{\left(D_i - D_{\sigma_{v_{max}}}\right)}{\left(R_{\oplus} - D_{\sigma_{v_{max}}}\right)} \cdot \cos(\mathrm{dip}°) \cdot \cos(\mathrm{strike}°) + \frac{E}{1-\nu^2}\,\frac{\left(D_i - D_{\sigma_{v_{max}}}\right)}{\left(R_{\oplus} - D_{\sigma_{v_{max}}}\right)} \cdot \cos(\mathrm{dip}°) \cdot \cos(\mathrm{strike}°) + \left(\frac{E\nu}{1-\nu^2}\,\varepsilon_H + \frac{E}{1-\nu^2}\,\varepsilon_h\right)_{tectonic} \quad (3)$$

Most wellbores target sands in above centroid structural positions. In these structural positions the sand reservoir pressure is above the bounding shale pore pressure by definition. The sands require raising the drilling fluids density to a hydraulic pressure above the sand pore pressure to keep the reservoir fluid from entering the wellbore according to well control principles. The higher up on the structure the sand is drilled the higher the reservoir pressure will be relative to the shale pore pressures. Extreme apex wellbores exceed the shale pore pressures and if above the FC they very easily exceed the shale fracture pressure. In this scenario the shale fractures and the sand won't.

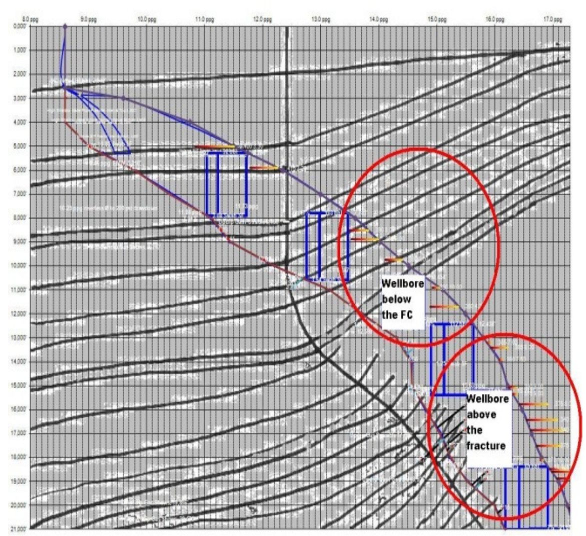

Figure 7—example of above and below FC conditions. Red→yellow horizontal gradient bars are $P_{f_{sand}}$ from FC to min or max.

The drilling fluid propagates shale fractures that are constrained in height and length by the bounding high pressure and high fracture pressure sands as seen in the following figure.

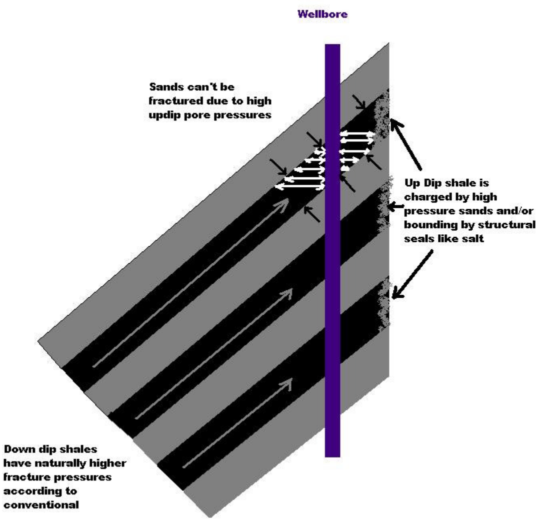

Figure 8—Illustration of above FC condition capable of trapping wellbore pressure resulting in a "ballooning" wellbore.

The drilling fluid can propagate no further than those boundaries and cannot be "absorbed" into high porosity and permeable sands, Thus the fluid lost during pumping at higher ECD's is relegated to return to the wellbore in the form of ballooning, with all of its often confusing surface indications. The rig personnel and engineering teams are left to deal with, after the pumps are turned off for connections for example, these confusing surface indications. That ballooning fluid often returns with shale gas as well as the drilling fluid further confuses the indications at the rig floor to an unwarned and prepared rig crew and engineering personnel.

Because these types of highly dipping formations are very common in the salt plays common to deepwater drilling and the well control equipment is mostly subsea and harder and slower to activate than on other type drilling rigs, avoiding the worst ballooning is even more important. Also, because of the well control issues involved and the need for safer conditions as the water depths continue to increase in deepwater drilling, being able to predict conditions where ballooning is likely is needed in designing wellbore trajectories. Because wildcat wells usually test updip traps, many exploration wells need to penetrate highly dipping reservoirs above the FC. If the actual conditions are accounted for in detail in advance of drilling operations ballooning may be avoided. By modeling conditions in advance, mud weights, hydraulics, kick tolerances and margins may be incorporated into casing setting depth designs that stay below the FC pressure at the shoes (Davis 2011b). If the fracture gradient of the shales are not exceeded the wellbore will not balloon. The connection of ballooning conditions with highly dipping formations at above FC penetrations is critical to safely drill increasingly difficult to access targets.

Of course above centroid penetrations of highly dipping sand/shale sequences are not the only places that ballooning can exist. Isolated sands with trapped pressure relative to the bounding shale also may exist with much higher pore pressures and fracture gradients than the shales above and below. In this case too ballooning will exist if the precise pressure and stress states exist. They may exist despite not having the structural addition to the minimum principal stress of sands and the diminished minimum principal stress of the shales that exist in highly dipping rigid sand column structures.

The elastic chamber required for ballooning

The precise hydraulic and pore pressure (P_p) and fracture pressure (P_f) condition that must exist for ballooning in all of these situations remains relatively similar. First of all the sand P_p must be very close to equal to the P_f of the shale bounding it. Of course the sand P_p must not exceed the shale P_f or the trap will leak. Many pinnacle locations of highly dipping bounded sands do leak off, though only slowly, over geologic time. These leaky seals serve as valves of maximum pressure from the apex of the sand downward and also serve to increase the net effective P_p of the bounding shales at the apex of these high pressured sands due to charging via high pressure fluid plumes.

Although once P_f of the shale is exceeded some additional pressure is required to propagate the fracture within the bounds of the surrounding high fracture pressure sands. These minute details have not been discussed in this paper in deference to the bigger picture this paper endeavors to focus on. The elastic chambers of ballooning shales may be made up of several, of many different, barriers to fracture propagation.

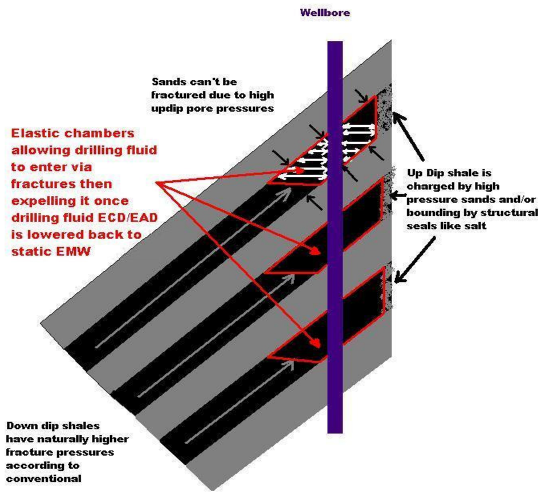

Figure 9---Elastic Chamber

These bounds form essentially elastic chambers where fluid can be elastically stored and yet not released to be absorbed and lost completely. As we can see these conditions are required for ballooning to happen. Note that in these highly dipping reservoirs the sand P_p upper limit can reach the shale P_f and exceed it to the fracture propagation pressure of the shale. Also note that as the fracture fills with more drilling fluid the fracture width increases. The pressure to propagate the fracture in the shale will increase as the fracture width increases because the height and length of the fracture is limited by the high P_p and P_f of bounding sands. Many of these shales are "charged" up dip and up structure and are bounded by above FC sand down dip and increasing P_f shale down structure. In this example an elastic chamber thusly exists and the size of this chamber determines the volume and characteristics of the ballooning. As the fracture builds the volume of losses diminishes because the pressure to propagate the fracture increases. Once the fracture tip reaches an unfracturable boundary at a high P_p and P_f bounding sand and updip charged shale zone and an increasing shale P_f down structure, the fracture length and height can no longer grow and only the fracture width may increase. The increasing fracture width requires increasing pressure to open further. As the balloon is allowed to flow back into the wellbore the opposite is seen. Initially the pressure and flowrate into the wellbore is high and it gradually diminishes as the fracture length and width closes in. If a wellbore penetrates an elastic chamber thus described the shale may immediately fracture and the wellbore fluid will fill these fractures until the shale P_f + fracture propagation pressure equals the pressure exerted by the drilling fluid in the wellbore at the time. The volume of ballooning fluid may then be estimated by the following relation:

$$V_f = h_f \cdot l_f \cdot w_f \text{......................................} (4)$$

Where: $h_f = fracture\ height$
$l_f = fracture\ length$
$w_f = fracture\ width$

Another fracture barrier comprising the elastic chamber of the example that hasn't been discussed yet is the stress that keeps the fractures from growing in the lateral direction along the bedding planes. This can be explained by keeping in mind that fractures will form in the direction of the maximum principal stress. In the case of highly dipping sands against a salt trap it is well known and mostly understood that the maximum horizontal stress radiates outward compressive stresses from the face of the salt. This will cause the fractures to orient and grow directly toward and away from the salt and so makes our two dimensional diagram accurate in portraying that there is no fracturing in the direction of the third dimension. Similarly, most highly dipping sands, whether they terminate into a salt face or up against a fault trap have an increased horizontal stress component normal to the strike of the fault at the proximal apex sections of the shale, and in the direction of the apex. This is due to the horizontal stress added by the deflection of overburden stress normal to the fault plane. This radiates outward of the fault trap similar to the outward compressive stress adjacent to salt faces. The description of these stresses and the mechanics of the fractures opening and closing are generic. There are variations on this general scenario, yet the basis of all of these variations must meet the specific criteria discussed above. There can be much detailed work done to determine fracture propagation pressures, fracture width, and anticipated fracture height that can model with precision the exact pressures to expect and volumes to be involved if a ballooning environment must be drilled through or is unexpectedly encountered. These determinations vary little from the analysis that goes into the pre-planning of a shale fracture stimulation job.

Summary
This paper addressed the issue of ballooning in drilling and gave a geomechanical explanation and means for understanding, predicting and mitigating the issues. It is my belief that in better understanding the phenomena of ballooning communicating in interdisciplinary teams and conveying issues and instructions between the rig and the office will be greatly enhanced. The result should save time in diagnosing the problems and in implementing the solutions and also result in much safer operations and better plans. In most cases ballooning can be predicted for any trajectory and casing setting depth design using the concept of the FC and an alternative trajectory and/or casing setting depth designed that will avoid the worst conditions or eliminate the ballooning entirely. By changing the trajectory and/or casing setting depths the well designer may place wellbore locations in advantageous positions relative to the PC and FC. If this concept is used to prevent wellbores with extremely high risk of ballooning, these screening and design methods will be responsible for eliminating one of the most, if not the most significant, causes of well control incidents and NPT in the industry.

Nomenclature

$\propto$ = poroelastic coefficient

BT = Ballooning Threshold = $P_{f_{min_{shale}}} - P_{p_{max_{sand}}}$

$D_{\sigma_{v_{max}}}$ = depth at which the vertical stress is maximum for the total interval planned to be drilled.

D_i = depth of interest

ΔP_{swab}= reduction of bottom hole pressure in a wellbore due to swabbing effect of pulling pipe.

E = Young's Modulus aka Elastic Modulus

ε_H = strain in the direction of maximum horizontal stress tectonic & tri-lateral compaction (TLC)

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EAD = equivalent annular density includes the added weight of circulating mud and cuttings load.

$\mathrm{EAD}_{\text{reduce ROP}}$ = equivalent annular density while control drilling at reduced ROP to minimize losses.

ECD = equivalent circulating density includes the friction pressure of the circulating mud system.

ESD = equivalent static density of the pressure a drilling fluid column exerts at the hole bottom.

FC = fracture centroid depth

$\mathrm{h_f}$ = fracture height

$\mathrm{l_f}$ = fracture length

PC = pressure centroid depth

P_f = fracture pressure

$P_{\boldsymbol{f_{sand}}}$ = fracture pressure of a sand

P_p = pore pressure

$P_{f_{min_{sand}}}$ = Minimum fracture pressure of all sands in any open hole interval

$P_{f_{min_{shale}}}$ = Minimum fracture pressure of all shale in any open hole interval

$P_{p_{max_{sand}}}$ = Maximum of all sand pore pressures in any open hole interval

$R_{\oplus}$ = radius of the earth ~ 20,903,520 ft

S_h = minimum horizontal stress in a normal faulting regime

S_v = overburden stress

TLC = Tri-Lateral Compaction equation

$$\mathrm{S}_h = \frac{\nu}{1-\nu}\left(\mathrm{S}_v - \propto P_p\right) + \propto P_p + \frac{E\nu}{1-\nu^2}\cdot\frac{(D_i - D_{\sigma_{v_{max}}})}{(R_{\oplus} - D_{\sigma_{v_{max}}})}\cdot\cos(\mathrm{dip}^\circ)\cdot\cos(\mathrm{strike}^\circ) + \frac{E}{1-\nu^2}\cdot\frac{(D_i - D_{\sigma_{v_{max}}})}{(R_{\oplus} - D_{\sigma_{v_{max}}})}\cdot\cos(\mathrm{dip}^\circ)\cdot\cos(\mathrm{strike}^\circ) + \left(\frac{E\nu}{1-\nu^2}\,\varepsilon_H + \frac{E}{1-\nu^2}\,\varepsilon_h\right)_{tectonic}$$

ν = Poisson's Ratio

$\mathrm{V_f}$ = fracture volume

$\mathrm{w_f}$ = fracture width

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