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A REVIEW OF WELLBORE INSTABILITY DURING WELL CONSTRUCTION: TYPES, CAUSES, PREVENTION AND CONTROL

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Abstract

Since early 1980s, the oil and gas industry has committed a huge amount of resources towards solving the problem of wellbore instability. Investments in wellbore stability studies are justified by the reduction in drilling and field development costs associated with a stable wellbore. A lot of progress has been made so far. However, wellbore instability continues to present a considerable challenge during well construction operations. The causes of instability and the mechanism of instability especially in shale formations have been studied over the years by several researchers. The results of their experimental and field experiences lead to varying conclusions and differing opinions. This work reviews existing technologies and practices within the industry directed towards understanding the causes of, predicting, preventing, and controlling wellbore instability; highlighting in the process, their limitations and making relevant suggestions. Field examples also provided to buttress some points.

Keywords: wellbore instability; principle stresses; shale; shear failure; tensile failure.

1. Introduction

Ensuring the stability of boreholes became an important aspect of drilling in the early 1980s when long, highly inclined wells began evolving for effective offshore and onshore development of large reservoirs. In addition to this, the re-entry of producing and abandoned wells, by side tracking, in mature oil fields, where earlier hydrocarbon production and earlier rock-drilling fluid interaction have resulted in changes to rock mechanics in the field, increases the necessity of wellbore stability studies.

Today, geomechanics has become a discipline in petroleum engineering and geomechanical analysis a standard practice for the construction of most oil and gas wells, in order to reduce drilling risk and cost. Minimizing rig time is a great contribution towards cost reduction goal.

One of the approaches towards reducing rig time is to take measures that avoid wellbore instability during drilling and well completion operations. Wellbore instability consists about 10-15% of extra drilling costs [1-2]. Wellbore instability is the main concern of drilling operations, resulting in higher than necessary drilling costs, extra rig time and sometimes in a loss of parts of or even the whole well. Wellbore instabilities make the data acquisition very difficult as well as the interpretation [3].

A well is considered stable if the diameter of the well matches the diameter of the bit and this is maintained over the entire length of drilling and completion time. In contrast, geomechanical instability refers to the mechanical conditions such as wellbore collapse or failure. In general, wellbore instability is related to drill pipe sticking, tight spots, cavings production, wellbore collapse and unscheduled sidetracks. These conditions are mostly caused by unknown rock mechanics and lead to increased cost during drilling and completion operations [4]. Wellbore instability is characterized by a wellbore diameter that varies from bit diameter.

The problem in many cases builds up over a period of time starting sometimes from wellbore wall fragmentation. Fragments transfer to the annulus culminating in tight holes, pack offs and stuck pipes under poor hole cleaning condition. Instability can occur not only during drilling but also during completion operations. Wellbore instability is a natural function of the unequal mechanical stress and physicochemical interactions and pressures created when support in the material and surfaces are exposed in the drilling process of the well [5].

Although a lot of work has been done and progress recorded in the field of wellbore instability and a lot of models developed for instability analysis, borehole instability related problems continue to pose a threat to successful drilling and completion operations and continues to contribute a substantial amount to annual industry expenditure on drilling. It is a continuing problem which results in substantial yearly expenditures by the petroleum industry, costing the oil industry over US$500–1000 million each year [6-7]

While wellbore instability is also encountered in vertical wells, it is a challenge more commonly encountered in highly deviated and horizontal wells. This in part is due to the difficulties that accompany hole cleaning in such wells. If the buildup region is at the shale cap rock as is often the case, chances of wellbore instability become exacerbated. More recent drilling innovations such as underbalanced drilling technique, high pressure jet drilling, re-entry horizontal wells and multiple laterals from a single vertical or horizontal well often give rise to challenging wellbore instability question [8].

A proper design of any well should include a study of mechanics of the rocks that will likely be encountered in the process of drilling; including the integrity, strength and the stress regime of such rocks. A poor understanding and or inadequate consideration of these can lead to severe instability issues during drilling and or completion. Drilling equipment must be designed to drill through different rock materials, but the design should also be such that when drilling through the rock, the rock formation integrity is not changed thereby not affecting the stability of the drilled well [9].

Rock mechanics postulates that drilling through any rock formation changes the stress pattern of the formation due to a loss of particles which hitherto had served as supporting materials to the formation and helped maintain balance within it. The process of drilling induces both radial and tangential stresses that lead to increased shear stresses. In situations where a combination of drilling practices and drilling fluid properties fail to compensate adequately and effectively balance out the new stress regime, wellbore collapse or stuck pipe may arise. On the other hand, if these factors produce an overbalance beyond formation strength, the formation gets fractured; another form of wellbore instability situation.

While wellbore collapse has received a relatively larger coverage in wellbore instability studies, formation fracturing can be very devastating as well. In accessing wellbore stability, any variations of well diameter from the diameter of the bit in use, in form of hole enlargement or reduction in wellbore diameter is an indication of instability in the section under examination.

When drilling a new well in an old field, offset data from previous wells drilled in the field can give an idea of formation situation in the field and serve as a guide on what drilling fluid type and parameters might be used to escape instability and its related problems. However, this should be done with caution especially when the inclination of the new well and or its azimuth varies significantly from that of the earlier well. For instance, offset wellbore stability data from a vertical well applied to a horizontal well will be misleading even when the two wells are drilled in the same field and in close proximity.

Ensuring a stable wellbore is a sure way of reducing drilling cost and its neglect can be catastrophic both in cash, time and resources. This work reviews the earlier works that have been done in the area of wellbore instability; highlighting the causes of instability, types of instability, instability analysis models and methods of preventing and controlling wellbore instability during drilling and completion operation; pointing out the shortcomings of earlier wellbore stability models, the improvements in later models and suggesting parmameters that when studied and properly integrated into wellbore stability analysis and models, will improve the performance of such models in stabilzing both shale, poorly cemented, soluble and hard brittle formations.

2. Types of wellbore instability

Wellbore instability occurs in different forms. These forms vary from their causes, the degree of damage inflicted on the wellbore and drilling or completion operation to the methods of controlling them. In most available literature, wellbore instability situations are classified either as a shear failure or a tensile failure. However, Fjær and Holt [10] identify three main types of failure that apply to rocks in the Earth: Shear failure, tensile failure, and compactive failure [10]. The various types of wellbore instability include:

1. Wellbore collapse
2. Tight spots/tight holes
3. Wellbore fracture
4. Hole enlargement
5. Shale failure

Tensile failures occur when the strain created by borehole pressure exceeds the internal stress of the rock formation. This sometimes, is also referred to as stress failure. An example of tensile failure is wellbore fracturing. On the other hand, shear failures occur when the strain created by the borehole pressure is less than the rock formation's internal stress. Examples include: wellbore collapse and tight holes.

2.1. Wellbore collapse

Wellbore collapse occurs when the hydrostatic pressure of the bore hole is too low to keep the wellbore in shape. That is, at borehole pressure values less than the principle horizontal stress of the formation. Wellbore collapse can lead in severe cases to a total loss of the well-bore and in milder cases to a stuck pipe situation. Al-Buraik and Pasnak [11] analyzed drilling problems that were encountered in more than 12 horizontal wells. These wells were drilled both in sandstone and carbonate reservoirs in Saudi Arabia. In sandstone reservoirs, the well-bore passed through shale and shale–sand stringers before reaching target depth. Three of these wells suffered from borehole collapse leading to stuck pipe. An extended exposure time worsened wellbore collapse due to the mechanical instability of shale [11]

2.2. Tight holes

During drilling, tight holes, a sever decrease in wellbore diameter in a section or sections of the wellbore, occurs as a result of any of or a combination of the following reasons: dog leg severity, inward creep of the wellbore, shale swelling and low borehole pressure. This condition can lead to stuck pipe, difficulty in casing landing, difficulties in hole cleaning and difficulties in cementing process.

In 1991 lost time due to stuck pipe related drilling problems accounted for approximately 18% of total drilling time in Mobil Producing Nigeria (MPN) Ultd's offshore operations [12].

2.3. Hole enlargements

Hole enlargement, also referred to as washouts in some literatures, is a wellbore instability situation in which the wellbore diameter becomes undesirably larger that the of the bit that has drilled the section. This can be caused by hydraulic erosion, mechanical abrasion caused by drill string vibration and inherently sloughing shale among others.

The negative consequences can be observed in hole cleaning, poor logging results and difficulty in cement placement behind casing.

2.4. Wellbore fracture

Fracturing occurs when borehole pressure exceeds the values of the horizontal stresses of a formation along the wellbore. When this happens, a lost circulation usually follows, which depending on its degree, can lead to a large decrease in the level of drilling fluid in the wellbore and consequently its hydrostatic pressure with a risk of possible blow out.

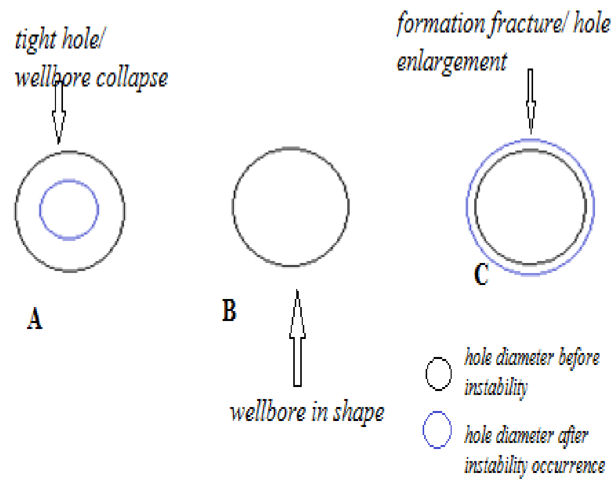

Fig.1. Effect of borehole pressure and horizontal stress ratio on wellbore stability.
A. Mud weight lower than the horizontal stress; B. Mud weight equal to the horizontal stress;
C. Mud weight higher than the horizontal stress.

Figure 1 above presents a simplified version of wellbore instability issues where the minimum and maximum horizontal stresses around the wellbore are equal. In field situations where these values vary, wellbore instability can lead to an uniform decrease or increase in hole diameter different from the patterns represented above.

2.5. Shale instability

While each of the above type of wellbore instability can be classified as either shear or tensile failure, shale instability can occur in some cases as a shear failure, when caused by insufficient borehole pressure, and in other instances involves a complicated mechanism that involves shale interaction with drilling fluid. In shale formations, wellbore instability can occur as a physical process and in other cases as a physico-chemical process that involves shale interaction with drilling fluid components. A detailed discussion of this process is presented in section 3, ‵′Shale chemistry and instability ″. While analyzing stuck pipe problems in her offshore operation in Nigeria, MPN in 1991 concluded that the borehole enlargement from sloughing of mechanically weak shale intervals in close proximity to in-guage mechanically stronger sandstone stringers was the fundamental cause of high frequency of stuck pipe. The ellipticity of the wellbores and hole enlargements of up to 22 in. through the intra Biafra and Qua Ibo shales strongly indicated that the wells were drilled with insufficient mud weights and therefor suffered from mechanical wellbore instability [12].

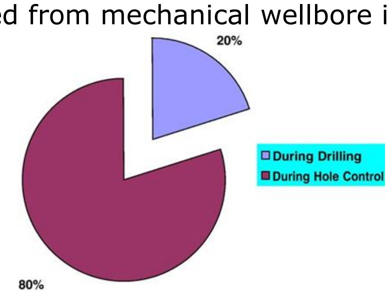

Fig.2. Problems during drilling and hole control phases [13]

The analysis of drilling data of sixty wells from an oil field by Mohiuddin *et al.* [14], found that the compiled data of instability instances from the daily drilling reports (DDR's) showed that 80% of these problems occurred during hole control and only 20 percent of the problems occurred during drilling. Typically, hole control problems occur before or during the placement of casing, therefore they are time delayed [13].

3. Causes of wellbore instability

In general, wellbore instability is caused by the presence of one or more mechanisms of instability. Wells drilled in complex geological areas encounter many layers of rock having different properties. Some layers could be weak, while others brittle, fractured, chemically reactive or rubble. There is no simple solution for wellbore instability in such cases. A collapsing weak layer needs high mud weight for stability, but increasing the mud weight could excite instability in fractured layers by mud invasion. Therefore, such cases require careful rock characterization and mud weight optimization [14] in proper selection of additives that will improve drilling fluid performace. These causes of wellbore instability are grouped under three interrelated headings: Mechanical, Rock-chemical interactions and manmade causes [15].

1. Mechanical causes. Key parameters are: rock stresses/Rock Types and rock strength/weakness.
2. Rock chemical interactions(Shale)
3. Manmade (Drilling practices). This includes: Lack of adequate well planning (example: Selection of wrong inclination & azimuth, selection of wrong drilling fluid system) and Improper (poor) drilling practices (examples: excessive wellbore pressures, poor hole cleaning, excessive drill string vibrations).

These causes are either controllable or uncontrollable/natural. Through proper adjustments to the controllable causes such as drilling fluid density, the negative effects of the uncontrollable causes can be minimized and in some cases eliminated.

Table 1. Causes of wellbore instability

Mechanical causes	Manmade factors/drilling practices	Rock-fluid interaction
Tectonically Stressed Formations Naturally	Bottom Hole Pressure (Mud Density)	Physico-chemical Rock-Fluid Interaction
Anomalously high In-situ Stresses	Well Inclination and Azimuth	
Naturally Over-Pressured Shale Collapse	Transient Pore Pressures	
Unconsolidated Formations	Induced Over-Pressured Shale	
Mobile Formations	Drill String Vibrations	
Fractured or Faulted Formations Collapse	Erosion	
Soluble formations	Temperature	
	Hole cleaning practices	
	Poor hole cleaning	

3.1. Mechanical causes of wellbore instability

A. Tectonically Stressed Formations: These formations usually occur in areas close to mountains and are the result of tectonic plate movements that either lead to formation compression or stretching. Wellbore instability in these formations arises when the hole pressure created by the drilling fluid is significantly lower than the near wellbore stress within the formation.

The presence of splintery carving in the returning drilling fluid is a pointer to tectonically stressed formation. Increasing mud weight will usually help avoid or overcome instability in these formations. However, the mud weight required may be greater than the fracture gradient of other exposed formations along the wellbore.

B. Anomalously high in-situ stresses*:* such as may be found in the vicinity of salt domes, near faults, or in the inner limbs of folds may give rise to wellbore instability. Stress concentrations may also occur in particularly stiff rocks such as quartzose sandstones or conglomerates [16].

C. Naturally Over-Pressured Shale Collapse: In these shale formations, the natural pore pressure of the formation is higher than the normal hydrostatic pressure of a column of pure water. The use of insufficient mud weight in these sections of the wellbore can lead to wellbore collapse.

D. Naturally fractured or faulted formations: Naturally fractured or faulted formations along the wellbore are usually zones of weakness. If these fractures occur in shale formations, they can become a conduit for drilling fluid invasion which, depending on fluid chemistry, may lead to formation strength degradation over time, shale swelling and an ultimate collapse of the section. A natural fracture system in the rock can often be found near faults. Rock near faults can be broken into large or small pieces. If they are loose, they can fall into the wellbore and jam the string in the hole to help stabilize such formations, Bowes and Procter suggest minimizing drill string vibrations [17-18].

E. Unconsolidated formations: The effect can be a gradual increase in drag over a number of meters, or can be sudden [18]. These formations usually occur at shallow depths as a result of small overburden pressure value consequent to which the formation are loosely packed with little to no bonding between neighboring particles. Borehole pressure alone is insufficient to hold them back as the fluid rather flows into the formation under high hydrostatic pressure. The falling of rock particles from this zone into the wellbore distorts wellbore diameter and in the presence of insufficient hole cleaning, these particles can lead to a pack off of the drill string*.* To drill through these formations successfully, an adequate filter cake is required to help stabilize and keep the unconsolidated rock in shape.

F. Mobile formations: These are formations which have a tendency to flow or squeeze into the wellbore under insufficient hydrostatic pressure. This happens as a result of the force of compression exerted on them by the overlaying rock mass. Their deformation leads to a decrease in hole diameter, difficulty with landing casing and logging tools and hole cleaning problems. Maintaining sufficient drilling fluid weight while drilling through such intervals is required to help stabilize them.

G. Soluble formations: These are rocks, mostly salt formations, which when in contact with certain forms of drilling fluid dissolve in them to form solutions. For instance, drilling through a NaCl formation using water based drilling fluid leads to formation dissolution in the fluid. Such dissolution results in loss of control over wellbore diameter and shape, leading usually to hole enlargements.

3.2. Man-made factors/drilling practices

A. Bottom hole pressure (drilling fluid density): The density of the drilling fluid which has a direct influence on the bottom hole pressure is often time the most important property of the drilling fluid affecting wellbore stability in most formation intervals. Depending upon the application, either the bottom hole pressure, the mud density or the equivalent circulating density (ECD), is usually the most important determinant of whether an open wellbore is stable [17,19]. During drilling, the support provided by this pressure determines the stress concentration in the near wellbore zone. During cementing, the density of the cement solution has a similar effect on wellbore stability. However, drilling fluid density, equivalent circulating density of bottom hole pressure is not the only parameter that determines stability. Optimizing them without appropriate filter cake formation will not control instability in unconsolidated formations.

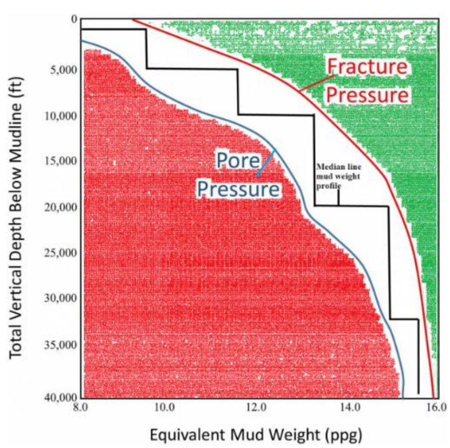

Fig.3. Alternative mud-weight schedules [20] with modifications

Figure 3 shows three lines of pressure and three regions represented by different colours. Drilling activities at equivalent mud densities in the red zone, below the blue line (pore pressure), will lead to a kick and a possible blow out situation. In mobile formation, over pressured shale formations and tectonically stressed formations, this will lead to wellbore collapse. On the other hand, drilling at equivalent mud weight values to the right of the red (fracture pressure) line will lead to formation fracture. The resulting loss circulation can lead to a number of other complications during drilling.

In the drilling industry recent experience favours drilling using mud equivalent mud weights in the white coloured zone along the median line mud weight profile. This principle determines the optimum mud weight for drilling while taking the risks of wellbore collapse and formation fracture into account. Aadnoy reports a reduction in wellbore instability issues evidenced by decrease in tight holes and back reaming after invoking this principle [21].

B. Well Inclination and Azimuth: wellbore inclination and azimuthal orientation with respect to the principal in-situ stresses are important factors affecting wellbore stability. Using a linear elastic constitutive model along with Mohr-Coulomb failure criterion to perform stability calculation for different inclinations and azimuths, Abouzar *et al.* showed that drilling wells parallel to minimum in-situ horizontal stress causes less stability problems when the difference between in-situ horizontal stresses is high, low inclination wells are more stable than highly inclined boreholes. In the case of high difference between the in-situ stresses, the optimum path for a well is a low inclination and an intermediate azimuth. Theoretically, it is possible to design the well trajectory in a way to face least stability problems [22].

C. Transient wellbore pressures: Swab and surge effects create transient pressures during drilling. While swabbing leads to a decreased hole pressure, surging leads to an increased hole pressure. The effect of hole pressure on wellbore stability is discussed above. The rapid reduction of wellbore pressure caused by swabbing can lead to tensile spalling, carvings production in fractured formations, tight holes or eventual wellbore collapse. Surge pressures on the other hand can cause rapid wellbore pressure increase to levels above formation strength leading to formation fracture. A similar situation can arise during casing landing in the wellbore. Controlling the speed of tripping and casing landing operations can help moderate the values of these pressures and hence control instability.

Earlier calculations of swab and surge pressures were performed using approximate methods which assumed that the drilling fluid's properties were constant through the entire depth of the wellbore. The method developed by Burkhardt [23] was based on the Bingham fluid model while Schuh's [24] method was based on the power law model. The assumption of a constant drilling fluid property leads to shortcomings that make these methods ineffective for field applications. Based on the works of Burkhardt and Dodge and Metzner; and the works of Schuh and Dodge and Metzner, Fontenot [23- 26] developed equations for calculating swab and surge pressures for the Bingham and power law models respectively. The developed equations were programmed for computer solution which enables the investigation of complex well geometries. The program, with little modification can handle above 10 sections of different geometry, where each section has a uniform description.

Wilson Chin and Xiaoying Zhuang [27] details the development of a fluid-dynamical model with new capabilities in modelling steady and transient non-Newtonian flow in highly enccentric annuli, with or without plug zones associated with yield stress fluids, haiving realistic geometric anomalies, in addition to effects like borehole axis curvature and drillpipe translation and rotation. Its exact mathematical solution is augmented by rapidly converging algorithms that enables convinient estimation of swab and surge pressures in horizontal wells. More recently in 2012, Crespo *et al.* [28] developed a new steady-state model that can account for fluid and formation compressibility and pipe elasticity for accurate surge and swab pressure estimation. For the closed-ended pipe, the model is cast into a simplified model to predict pressure surge in a more convenient way. The success of this model in field applications is due to the application of a more realistic rheology model. The model is useful for slimhole, deepwater, and extended-reach drilling applications. Another model for predicting surge pressures in different intervals of horizontal wells using the program called mathematica was developed by Yuxue Sun *et al.* [29]. This model on simplification can also be used effectively in vertical and inclined wells. The model's developers argues that it can direct the secure production on location through predicting surge pressures under different working conditions of drill string.

The ability of these models to predict trasient surge and swab pressures is of great benefit in the industry in the fight against wellbore instability. They creat room for preventive rather than corrective actions to be taken at intervals prone to fracture or collapse to ensure a stable welbore and safe drilling; helping dictate pipe tripping and casing landing speeds in vertical, inclined and horizontal wells.

D. Drillstring vibrations (during drilling*):* Drillstring vibrations can be divided into three types, or modes: axial, torsional, and lateral (Fig. 4).

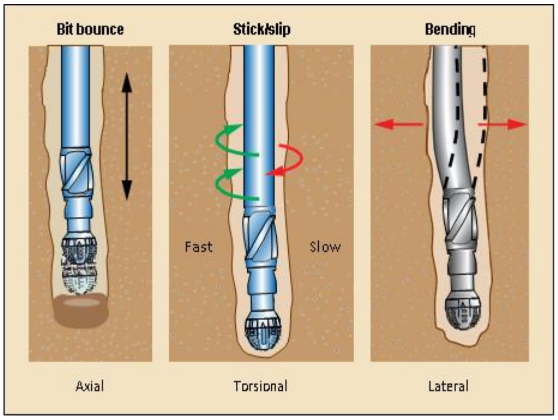

Fig.4. Types of drill string vibrations [30]

The destructive nature of each type of vibration is different. Lateral vibrations are the most destructive type of vibration and can create large shocks as the BHA impacts the wellbore wall [30]. This impact can create cracks in the formation and in some cases, lead to significant hole enlargements. Optimizing bottom hole assembly (BHA) design with respect to the hole geometry, inclination, and formations to be drilled is an important step in controlling drill string vibrations.

E. Drilling fluid temperature: Drilling fluid temperature can be affected by geothermal static temperature, circulating parameters, and the mud-circulating system. As the fluid passes through a particular formation during drilling, it either gains or loses heat depending on the temperature difference between it and the formation.

This either increases or reduces the fracture gradient of the formation. Wellbore temperatures that are cooler than those of the formation reduce breakdown (fracturing) pressure. Changes in wellbore temperature have a greater effect on the formation breakdown pressure than on the formation collapse pressure [31-32]. However, thermal effects have also been blamed for some wellbore collapses in which formations were heated by mud from deeper formations that ascended the annulus of the wellbore [3]. To determine whether the temperature of the drilling fluid directly affects the fracture gradient of the formation, technicians conducted a field test onshore in South Texas. The result was a 0.9 kbm/gal equivalent mud-weight increase in the effective fracture gradient for a temperature increase of 61°F [33].

F. Induced Over- pressured Shale Collapse: Shale intervals exposed to drilling fluid over a period of time assumes the hydrostatic pressure created by the fluid in the wellbore. If this period is followed by a reduction or a zero increase in mud weight, the shale which now has a higher internal pressure in the near wellbore zone than the wellbore pressure collapses in similar pattern to naturally over-pressured shale described above. This mechanism occurs more while using water based drilling fluids, after a reduction in drilling fluid density or after a long exposure time with no changes to the fluid density. Reducing exposure time and modifying drilling fluid density after an exposure period helps prevent instability.

G. Poor hole cleaning: Fred and Tim in Chapter 2 of Drilling Fluid Processing Handbook [34] noted that the advent of PWD (pressure while drilling) tools and accurate flow modeling, the following indicators have come to light that foreshadow poor hole cleaning and its attendant consequences. Among these are:

- ✓ Fluctuating torque
- ✓ Tight hole
- ✓ Increasing drag on connections
- ✓ Increased ECD when initiating drill string rotation.

While increased ECD (equivalent circulating density) can cause wellbore formation fracture, tight hole is a known type of wellbore instability.

3.3. Rock –fluid interaction

A. Physico-chemical fluid-rock interaction*:* The physical and chemical interaction between drilling fluid and formations in the open section of the wellbore can lead to phenomena that are potential initiators of wellbore instability situations. These include hydration, osmotic pressures, swelling, rock softening and strength changes and dispersion. The significance of these effects depend on a complex interaction of many factors including the nature of the formation (mineralogy, stiffness, strength, pore water composition, stress history, temperature), the presence of a filter cake or permeability barrier is present, the properties and chemical composition of the wellbore fluid, and the extent of any damage near the wellbore [35].

4. Shale chemistry and instability

The term shale is normally used for the entire class of fine grained sedimentary rocks that contain substantial amount of clay [36]. The clay content maybe smectite, illite or kaonite. Of these three the most water sensitive and hence, most unstable with water based drilling fluid is smectite clay. Smectite clays are of the type 2:1 and frequently occur in drilling situations [37]. They are rich in sodium ions and swell macroscopically giving rise to instability during drilling. These clays usually contain either of or a combination of the following forms: inter-crystalline water, osmotic water and bound water; which exists as hydrogen and hydroxyl groups that only separate from the clay to form water under extreme temperature conditions in the order of 600 degrees Celsius and above. Properties of shale and fluid/shale interaction are strongly influenced by bound water and to a lesser degree by free water.

Compaction, which occurs in three stages as the clay is buried by overlying rock mass and temperature rises, is accompanied by a loss of water from the clay. The first stage of clay compaction is controlled by the increasing pressure exerted by the overlaying rocks while the last two stages are controlled by temperature increases; the second starting at about 100^{o}C. The end result is a rock mass of very low permeability with reduced but active water content. clay/drilling fluid interaction introduces changes to clay water content. According to Manohar [36], prior to drilling, the amount of water present in clay depends on compaction history. However, from the time of drilling, the properties of drilled shale formation which are important for shale/fluid interaction and shale stability are dictated by the past compaction history and the current in stu stresses and temperature [36]. Detailed studies on of clay mineralogy can be found in the works of Grim and Murray [38-39].

It is reported that shales account for more than 70% of all formations drilled by the oil and gas industry with about 90% of wellbore instability occurring in shale formations [40]. O'Brien & Chenevert [41] in studying the relationship between shale instability and their clay mineralogy, classified problematic shales into five categories. This classification relates clay mineral composition to their tendency to hydrate and their relative hardness. The study identified smectite, illite and mixed-layer clays as the most active in causing shale instability, chloritic clay minerals are less active and kaolinite is not mentioned in the classification implying that it is relatively inactive. Atoms of different valences are usually positioned within clay mineral crystals structure to create a negative potential at surface of the crystal creating an adsorbtion surface for cations. On exposure to water and water containing fluids, these cations can chemically exchange places with other cations. Furthermore, ions may also be adsorbed on the clay crystal edges and exchange with other ions in the water [42]. This exchange of ions on the surface of and within clay crystals, in fractured shales, affect clay swelling greatly leading to increased volumes and a weakened shale that may result in instability.

Shale instability occurs in three forms: Mechanical instability, chemical instability and thermal instability.

4.1. Mechanical shale instability

Mechanical shale stability interplay of stress redistribution and shale rock strength as drilling fluid replaces rock mass during drilling. When the drilling fluid's density fails to create a pressure high enough to bring the altered stresses to the original state, mechanical shale instability is usually the consequence. Chen *et al.* [43] report that shale failure is primarily caused by the redistribution of in situ stress which subsequently exceeds the shear or tensile strength of the rock. This stress redistribution can also arise from:

A. Capillary pressure: Through the pore-throat interface drilling fluid can come in contact with the native pore fluid in shale leading to the development of capillary pressure with a possibility of shale instability.

B. Shale hydration: the clay component of shales possesses the ability to absorb water. This absorption of water otherwise called hydration leads to enlargement of the shale formation and consequent wellbore instability as a result of the swelling of some mineral present in the formation or due to an induced stress that leads to modification of the pore pressure to values that that surpass the supporting pressure created by the driling fluid.

4.2. Chemical shale instability

Chemical effects are caused by the imbalance between drilling fluid's water activity and shale water activity. The magnitude of this contribution depends on the effectiveness of the mud/shale system to perform as a semipermeable membrane.

Experimental results show that osmotic pressures develop inside shales when they are exposed to different drilling fluids. This osmotic pressure is treated as an equivalent hydraulic potential, and is then added to the hydraulic wellbore and pore pressure as time progresses. The osmotic pressure in a mud/shale system can be determined by the following expression,

$$p = -I_m \frac{RT}{V} \mathrm{Ln}[\frac{aw_m}{aw_{sh}}] \quad (1)$$

where, the gas constant R = 8.314 kg m2 s-2 g mol-1K-1; T = temperature, K; V = $1.8*10^{-5}$ m3/g mol, partial molar volume of the water; aw_m = mud water activity; aw_{sh} = shale water activity; and Im = membrane efficiency [44].

By modifying the chemical content of the drilling fluid, its water activity can be altered with a resulting change in the value of the osmotic pressure. The high water activity of water based drilling fluids is the reason for their poor performance in ensuring wellbore stability in shale formations.

In addition to osmotic pressure, chemical instability of shales occurs as a result of the following processes:

- ✓ Pressure diffusion in the near wellbore zone
- ✓ Drilling fluid invasion into the shale formation

Overbalanced drilling results in fluid invasion of rock formations. This process has a significant effect in shale formations because of the saturation and very low permeability of shale. The penetration of a small volume of drilling fluid filtrate leads to a considerable increase in pore pressure in the near wellbore vicinity. The increased pore pressure reduces the effective mud support, which can cause instability.

4.3. Thermal instability

Cooler muds can reduce pore pressure and increase collapse stress. Hotter muds can result in unstable shales and are not desirable in drilling operations. Thermal diffusion inside the drilled formation induces additional pore pressure and rock stress changes and consequently affects shale stability. Thermal effects are important because thermal diffusion into shale formations occurs more quickly than hydraulic diffusion and thereby dominates pore pressure changes during early time [7].

4.4. Mechanism of shale swelling and instability

Clay minerals in shale generally undergo two forms swelling [42]: a surface hydration; observable in all types of clays and osmotic swelling which results in larger overall volume increases than surface hydration, but only a few clays, like sodium montmorillonite, swell in this manner.

Gazaniol *et al.* [45-46] showed that several mechanisms can be involved in the process of shale instability during drilling: pore pressure diffusion, plasticity, anisotropy, capillary effects, osmosis, and physicochemical alterations. The following three processes contribute most significantly to instability of shales and therefore demands adequate consideration in shale instability analysis:

1. Movement of fluid between the wellbore and shale (limited to flow from the wellbore into the shale),
2. Changes in stress (and strain) that occur during shale-filtrate interaction, and
3. Softening and erosion caused by invasion of mud filtrate and consequent chemical changes in the shale [47].

Conventional notions of the mechanism of shale instability places emphasis almost always on the expandability of smectite, particularly when saturated with Na^+ in attempting to elucidate the role of clay mineralogy in relation to the instability of shales [48]. That is, on the osmotic exchange of ions between the clay minerals of the shale formation and the drilling fluid. This understanding is presented with varying modifications in such published literatures as: Norrish [49], Bol *et al.* [50], Van Oort [51]. Applying the results of these studies fails in many field circumstances; an indication of their imperfection. Such field observations led to the arguments presented by Mering & Oberlin [52], Ballard *et al.* [53], Santarelli & Carminati [54], Bostrøm *et al.* [55], and Carpacho *et al.*, [56] against the conventional mechanism of shale instability. While Santarelli & Carminati, based on evidence from their simulation tests and field experience, , expressed doubts concerning the reality of osmotic flow in shales, and concluded that shales do not swell downhole in situ, Carpacho *et al.*, presented evidence indicating that kaolinite-dominant shales can be highly unstable when drilled, and can give rise to bit-balling problems, which implies that a mechanism other than that of osmotic smectite interlayer expansion must be responsible given the relative inactivity of kaolinite clays.

It is suggested for many shales that invasion of fluids through heterogeneous features such as micro-fractures and sedimentary laminations leads to increased pore/hydration pressure in micro- and meso-pores where the charged external faces of the clay minerals are exposed. In this scenario the principal reason forshale instability would be the forced overlap of the diffuse double layer DDLs associated with the clay minerals [57]. Baohua Yu *et al*. [58] while studying the cause of instability in the Nahur Umr fractured shale formation; a brittle hard shale, where drilling fluid inhibition was not an issue, identified filtrate invasion into the fractures of the shale formation as the primary cause of instability. The instability of this formation led to wellbore collapse with consequent sidetracking in two of the three horizontal wells drilled through it in order to reach total depth. The situation was improved by use of a drilling fluid of higher viscosity and a better sealing capacity which controlled filtration into shale fractures.

In addition to the osmotic ion exchange and its consequent effect on stability that arises on filtrate invasion of shale, Wen *et al.* [59] proved that wettability is another factor which not only controls reservoir fluid distribution, but also greatly affects physical and chemical properties of rock, including capillary force, relative permeability, electrical properties and even strength. Especially before and after drilling formation, wettability exerts a more significant influence on wellbore stability. In most previous literatures, unchanged wettability was considered as a default premise, impact of wettability and its changes on the rock, thereby on wellbore stability was ignored.

Analysing the outcomes of the works cited above in combination with field experience, it is evident that the mechanism of shale instability involves not only the general osmotic swelling of smectite clays due to their hydrophilic nature but the overall texture of the clay present in drilled shale in addition to the structure and fabric of shales, play significant roles in determining the severity of instability of shale formations when exposed to aqueous fluids during well construction operation.

Another approach towards understanding crystalline swelling of smectite clay minerals in shale considers the process as a series of layer spacing transitions which are thermodynamically analogous to phase transitions. This approach is detailed in the works of Shroll *et.al.* and Whitley *et al.* [60-61]. While experimental study of the swelling process is possible, computer simulation of the process can provide information on crystalline swelling of clay minerals that is difficult or impossible to obtain experimentally [62]. Simulations can reveal the entire swelling potential along with its entropic and energetic components and makes structural information directly accessible for a clear correlation between structure and swelling thermodynamics [63]. The descriptions and results of such computer simulations are reported in the works of Hensel [62], Smith *et al.* [63], Frenkel and Smit [64] and Allen and Tildesley [65] among others.

Results of these simulations indicate that shale swelling is in large parts controlled by an energetic driving force with entropy playing a smaller compensating role and increasing clay layer role has a similar effect to increasing shale interlayer hydration energy by altering its size or charge.

Mechanical stability problem can be prevented by restoring the stress-strength balance through adjustment of mud weight and effective circulation density (ECD) through drilling/ tripping practices, and trajectory control. The chemical stability problem, on the other hand, is time dependent unlike mechanical instability, which occurs as soon as we drill new formations.

Chemical instability can be prevented through selection of proper drilling fluid, suitable mud additives to minimize/delay the fluid/shale interaction, and by reducing shale exposure time. Selection of proper mud with suitable additives can even generate fluid flow from shale into the wellbore, reducing near wellbore pore pressure and preventing shale strength reduction [36].

Chemical instability of shale is a major reason for the preference given to oil based and synthetic drilling fluid over water based fluid in drilling shale formations. Water-based drilling fluids are generally considered to be more environmentally acceptable than oil-based or synthetic-based fluids. However, the former type of drilling fluid facilitates clay hydration and swelling, which can lead to significantly increased oil well construction costs Anderson *et al.* [48]. The conventional process in the industry is to control swelling by use of inhibitors as drilling fluid additive. However, field results prove that inhition alone is usually insufficient for ensuring a stable shale. In addition to addition of inhibitors, viscosifiers and filtration control agents such as polymers play significant roles in controlling instability in shales. Expermental and field results in support of this are well documented in literature. The addition of increasing salt concentrations to a combination of anionic polymers (polyanionic cellulose PAC and xanthan) increases the viscosity of the solutions and the ionic effect of silicate, PAC, xanthan and the steric effect of partially hydrolysed polyacrylamide PHPA confer favourable rheological, filtration, and inhibitory properties to drilling fluids [66]. The use of inhibitors failled to control instability in Nahur Umr formation. To overcome this situation and successfully reach total depth, the vicosity and filtration properties of the drilling fluid were improved to reduce filtrate invasion of the bedding planes of the fractured shale.

Recent research in the preservation of monuments built with clay containing sandstone materials such as performed by Rodriguez-Navarro et al. [67], Schmittner and Giresse [68] and Sebastian *et al.* [69] reveal that all clay minerals, including chlorite and illite, may be subjected to osmotic-type swelling processes, if the pores in the rock contain an electrolyte in solution with NaCl considered as one of the most effective electrolytes in osmotic swelling of clay. These studies are of significant importance to the drilling industry as they shed light on the reasons for certain instability situations in shale formations. If salts are used as inhibitors in water based muds, shale instability could arise when mud filterates find their way into the pore spaces of the shale formation especially in fractured shales. Preventing filtrate invasion involves the use of fluid loss materials, improving mud rheology and proper hole pressure management during well construction operation.

The above understandings nothwithstanding, the uncertainty in accurately predicting exact shale water activity through the entire height of the formation makes the use of non- water based drilling fluids a preferred choice where cost and environmental restrictions permit.

5. Symptoms of wellbore instability

Wellbore instability occurring in a well manifests itself in different ways. These manifestations or symptoms of wellbore instability are classified into two categories as shown in the table 2 below: direct and indirect symptoms [10]. The presence of rock carvings in the drilling fluid arriving the surface from the wellbore, and hole fill after tripping out signify that spalling processes are taking place in the wellbore. Symptoms of hole enlargement include: Large volumes of carvings; in excess of the expected rock volume from a stable well of same diameter, a requirement for an extra volume of cement than the calculated drilled hole volume in wells where neither fracture gradient was exceeded nor was vuggy or naturally fractured formations encountered. When any or a combination of these symptoms are observe on the rig, necessary measures should be taken to establish the exact condition of the wellbore and restore its stability.

Table 2. Symptoms of wellbore instability during drilling and well completion operations [10]

Direct symptoms	Indirect symptoms
Oversize hole	High torque and drag (friction)
Undergauge hole	Hanging up of drillstring, casing, or coiled tubing
Excessive volume of cuttings	Increased circulating pressures
Excessive volume of cavings	Stuck pipe
Cavings at surface	Excessive drillstring vibrations
Hole fill after tripping	Drillstring failure
Excess cement volume required	Deviation control problems
	Inability to run logs
	Poor logging response
	Annular gas leakage due to poor cement job
	Keyhole seating
	Excessive doglegs

6. Borehole instability prevention and control

To prevent wellbore instability, the drilling fluid design and drilling practices should combine to create a pressure situation along the open wellbore that restores the natural stress regime of the formation before drilling and where instability is observed these parameters should be adjusted as quickly as possible with the aim of achieving this equilibrium. In addition to the pressure condition along the wellbore, the drilling fluid should be designed such that it doesn't weaken formations by either chemical or physical interaction. However, total prevention of borehole instability is unrealistic, mainly because the rock can never be restored to its initial conditions [44]. Adhering to the following practices during project design and development and actual well construction processes helps ensure stability of the wellbore:

- ✓ Proper mud-weight selection and maintenance
- ✓ Use of proper hydraulics to control the equivalent circulating density (ECD)
- ✓ Proper hole-trajectory selection
- ✓ Use of borehole fluid compatible with the formation being drilled
- ✓ Minimizing time spent in open hole
- ✓ Using offset-well data (use of the learning curve)
- ✓ Monitoring trend changes (torque, circulating pressure, drag, fill-in during tripping)
- ✓ Collaborating and sharing information [16].

Additional practices that enhance wellbore stability include:

- ✓ Proper wellbore cleaning and an adequate cuttings removal
- ✓ Proper selection of bottom hole assembly equipment to minimize drill string vibration
- ✓ Regulating the speed of tripping in and out of the well to minimize surge and swab pressures respectively
- ✓ Controlling the speed of casing landing to control surge pressure.

Another dimension to ensuring wellbore stability is ensuring that drilled cuttings do not disintegrate on their way to the surface. With other rock types controlling mechanical aspects of drilling such as circulation velocity and drilling string vibration can help prevent disintergration but with shale a chemical aspect is of enormous importance. The use of consolidation and hydrophobic additives in the drilling fluid which covers the surface of shale cuttings preventing hydration and osmotic pressure build up as cuttings move to the surface is necessary in this case. This effect is more easily and effectively achieved in non-water based drilling fluids especially synthetic and oil based drilling fluids.

In an attempt to ensure wellbore stability, researchers have conducted experiments aimed at strenghtening the wellbore during well construction and examining the efficiency of such wellbore strengthening materials. Wellbore strenghtning is a term used Wellbore strengthening is a term in drilling engineering that describes the artificial increase of the maximum pressure a wellbore can withstand without significant drilling fluid losses.

This process by increasing fracture gradient expands the mud weight window. Wellbore strengthening is commonly believed to work by bridging, plugging, or sealing the fractures from which mud losses occur [70]. Wellbore strengthening treatments can be either preventive or remedial. Simply put, preventive treatments attempt to "strengthen" the wellbore using lost circulation material (LCM) to prevent the creation of new fractures and extension of small pre-existing fractures on the wellbore wall before the lost circulation event. Remedial wellbore strengthening treatments attempt to "strengthen" the wellbore by bridging, plugging, or sealing the lost circulation fractures using LCM after a substantial loss has already occurred. In other words, while preventive strengthening intends to protect formations along the wellbore from induced fracture and etension of natural fractures, remedial treatments are basically a loss circulation control mechanism. The ultimate goal of wellbore stability studies is to as much as possible prevent instability. That is to develop a drilling practice and a drilling fluid system that ensure a stable wellbore throughout the well construction process. For this reason, this work gives priority to preventive wellbore strengthening over its remedial counterpart.

In preventive wellbore strengthening the drilling fluid is treated with certain additives called lost circulation materials. These materials in addition to aiding a speedy formation of a filter cake of high ductility and low permeability, quickly seals off any naturally occurring or drilling induced micro fractures in the formation [71-74]. This way, fracture initiation pressure of the formation is increase and filtrate invasion of the formation is prevented or drastically reduced.

The effect of filtrate invasion of shale rocks has been discussed above. It is important to note that the negative effect of fluid invasion is not limited to shale rocks; while studying core samples from an oilfield in Western China, Wen *et al.* [59] established that wettability of the rock surfaces plays an important role in the wellbore instability arising while using oil based mud. As a result of rock surface wetting by drilling fluid invading the micro and nano fracture of the formation, stress builds up over time that can lead to micro and nano fracture enlargement to macro fracture and consequent wellbore instability. This points to the fact that fluid filtrate invasion of micro fractures can be disastrous in other rocks other than shale. Field practices and recent experimental results prove that wellbore strengthening additives when added to drilling fluids facilitate the development of filter cake that improves the effective strength of the wellbore [75-77]. The success of wellbore strengthening additives is believed to be as a result of their ability to bridge fractures at the wellbore to increase wellbore hoop stress, and as a result of their ability to build a low-permeability mud cake on the wellbore wall to alter the effective stresses around the wellbore [71,78].

Laboratory experiments by Chuan *et al.* [79] show that Nano sealing can effectively strengthen wellbores in shale formations, whereas traditional highly macro sealing and inhibitive drilling fluid system cannot.

It is important however, to note that the formation of filter cakes and their physical properties are time dependent. A comprehensive understanding of the process of filter cake formation and variation of their physical properties with time are still subjects of further research.

7. Wellbore instability criterion and method of instability analysis

7.1. Wellbore instability criterion and stability model

A wellbore instability criterion defines the boundary conditions for maintaining a stable wellbore. The selection of an appropriate failure criterion, which represents the true in-stu failure conditions, plays a key role in any proper wellbore stability analysis. Wellbore failure or instability can be shear, tensile or compactive failure. Consequently, there are shear failure and tensile failure criteria. These criteria range from simple forms, which consider only the principle stresses to more complex forms, which take into account the effect of intermediate stresses on rock stability.

The Mohr-Coulomb rock failure criterion is the most commonly used shear failure criterion employed during wellbore stability analysis. Under this, failure occurs when the value of the maximum shear stress developed on a specific plane, is enough to overcome the formation cohesion (S_0) and frictional force. This failure depends only on the maximum (σ_1) and minimum (σ_3) principal stresses. The Mohr-Coulomb criterion can be described by the following equation:

$$\tau = S_0 + \sigma_n \tan\varphi \quad (2)$$

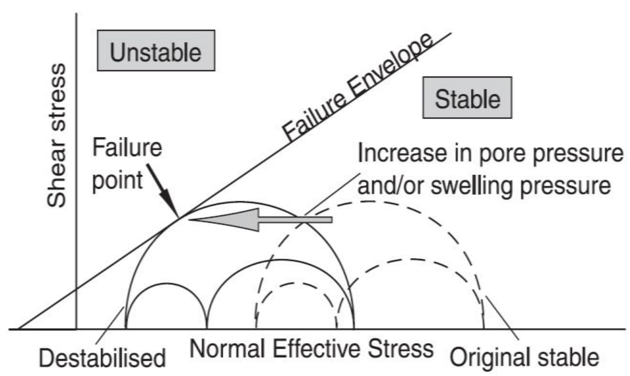

Fig.5. Mohr– Coulomb representation of shale failure: the increase in pore pressure and/or swelling pressure will reduce all effective normal stresses (note that shear stresses remain unaltered) until the stress state touches the failure envelope and the shale fails for a given orientation around the wellbore. *Reproduced after* [51]

By excluding intermediate stress, this criterion underestimates rock strength. Theoretically, there are six possibilities for shear failure, based on the magnitudes of the principal stress components at the borehole wall [10].

Other wellbore failure criteria include the Drucker-Prager criterion which unlike the Mohr-Coulomb criterion accounts for intermediate principal stress ($\sigma 2$), Modified Lade criterion, the Hoek and Brown criterion and the Tresca criterion amongst others. The Tresca criterion is a special case of the Mohr-Coulomb criterion where, $\varphi = 0$ in equation 2.

The Drucker–Prager failure criterion, as used in many literatures, is alleged to generate an unconservative critical mud weight window by overestimating rock strength [80]. By taking into account the intermediate stress with appropriate manipulations the modified Lade failure criterion can predict the rock strength closest to test results, compared to other failure criteria such as Drucker–Prager criteria and Mohr–Coulomb criteria [81]. A wellbore stability model was developed that takes into account both the mechanical and chemical aspects of the interactions between drilling fluid and shale formation [82]. This model accounts for the chemically induced stress alteration arising from the thermodynamics of the difference between free energy of drilling fluid and shale water in combination with the mechanically induced stress. This makes the model useful in estimating optimal drilling fluid density and salt concentration for shale inhibition. Another model for wellbore stability developed by Wilcox [84] takes account of the surface area, electric double layer effects and the equilibrium water content pressure relationships in characterizing wellbore stability. A new probabilistic wellbore stability that model runs Monte Carlo simulation to capture the effects of uncertainty in in situ stresses, drilling trajectories, and rock properties that predict the critical drilling fluid pressure before the onset of a wellbore collapse was developed and applied to different in situ stress regimes: normal faulting, strike slip, and reverse faulting. Sensitivity analysis was applied to all carried out simulations and found that well trajectories have the biggest impact factor in wellbore instability followed by rock properties [84].

Based on hypothesis of static load, traditional wellbore stability analysis models cannot reveal the real mechanism of irregular large-scale collapse phenomena experinced during horizontal drilling in brittle shale formations. In this process, borehole rock suffers dynamic load originating from impact of bit, hit of drilling tool and chemical action of drilling fluid. The micrometer or even nanometer cracks, triggered by dynamic load, will not destroy the rock immediately, but accumulate and then aggravate the development of macroscopic fracture until rock failure after a period of time [79]. Elsewhere, Yin *et al.* [85] present a fully coupled approach to wellbore stability modeling with thermal and solute convection considered. Its applicability is however, limited to problems such as naturally fractured shales where the scale of the fracture spacing allows a homogenization approach so the medium can be treated as a continuum.

The input parameters needed for any well stability analysis can be grouped into three. They are:

- ✓ Formation conditions,
- ✓ Wellbore and drilling fluid data and
- ✓ Formations properties.

While in situ stress, pore pressure and temperature are formation condition parameters, rock mineralogy, porosity, permeability, diffusion constant, strength parameters, elastic parameters, thermos-elastic parameters, poro-elastic parameters, chemo-elastic parameters, plastic parameters are formation property parameters and such parameters as Inclination and azimuth, well diameter, physical and chemical properties of the drilling fluid are wellbore and drilling fluid parameters. The stability will depend on the degree of uncertainty of all above parameters, but some input is more important than others [86]. Guizhong *et al.* [7] present a clearer list of factors that are important for a successful modelling of wellbore stability. They include: unequal horizontal in situ stresses, membrane efficiency, water activity ratio (between the drilling fluid and shale formation), pore pressure, rock strength, the ratio of shale hydraulic diffusivity to thermal diffusivity, the thermal coupling coefficient cV, thermal expansion coefficients of shale and pore fluid, and the temperature difference between the drilling fluid and the formation.

A successful welbore stability criterion would be one which is based not only the understanding that the wellbore is subject to a dynamic load mechanism especially in high inclination wells but also on a good underatnding of the strength and rate of formation of a filter cake by the drilling fluid intended for use under the prevailing reservoir condition.

7.2. Method of wellbore instability analysis

In analysing wellbore instability, both the wellbore wall and the entire near wellbore area need to be inspected for failure because the location of shear failure can be displaced inside the formation. Two effects can cause the displacement of the initial collapse failure location: (1) the poroelastic effect of equalized pore pressure at the wellbore wall, and (2) the thermal diffusion between the wellbore and the formation [7].

Aadnoy [87], presents a general methodology of analyzing the stability of a wellbore for both fracturing and collapse. This is valid for all stress states (normal, strike-slip, and reverse) and for all borehole orientations. The method involves the following calculation procedures:

- Calculate the stresses in the direction of the borehole.
- Insert these data into the borehole stress equations.
- Determine the point on the borehole wall where failure will occur.
- Implement a failure model.
- Compute borehole pressure at failure [87].

The value of the determined borehole pressure at failure dictates the mud window chosen for the interval analyzed. However, as already proven above, mud weight is not the only factor that determines the success of a wellbore stability model. Considering the other factors that affect instability at the stage of analysis will greatly improve accurracy and field applicability. In essnece, to properly model wellbore stability in poorly cemented formations, the consolidating property of the drilling fluid should be considered in addition to other drilling fluid properties listed above. In addition to this, the friction reduction property of the drilling fluid and the impact of drill string contact with the walls of the wellbore should also be given adequate attention especially in highly inclined and horizontal wells. In sidetracks in wells of mature fields, an effective wellbore stability model will be one which considers the effect of earlier drilling and production activities on the rock strength and pore pressure. Wellbore stability models used for earlier drilling in such fields often fail to replicate their successs during side-tracking operations.

8. Recommendations

Based on this review, its obvious that the drilling industry understand the enormity of the challenge presented by wellbore instability to the cost and success of well construction and has dedicated great amount of resources and time to combating instability. However, the challenge of wellbore instability remains real even today. Based on this, the following recommendations can be made:

1. More work should be directed towrads improving the capcity and efficiency of measurement while drilling equipment to give the driller an up to date information of the nature of the formation being drilled at every given time. Such equipment should be designed to detect and report the smallest fractures existing in the formation and the minutest of induced fractures arising from dynamic loading. This will help shift the industry's response to instability from a remiadial to a more preventive approach.
2. Commonly used wellbore stability models should be improved upon to capture the effect of all factors that influence wellbore stability.
3. Future studies should investigate the effect of lubrication additives on wellbore stability; to quantify their effect on the impact between drilling equipment and the wellbore wall, collision between drilled among drilled cuttings and that between cuttings and the wellbore. This is of great importance to horizontal wells especially those of small diameters.
4. More research should directed towards the development of sealing agents and consolidation additives that function effectively over varying temperatures and pressures. In addition to this, efforts towards understand the mechanism of mud cake formation and their physical properties' variations over time should be intensified.
5. With little research published so far on wellbore stability during sidetracking in mature fields and the increasing re-entry and sidetracking of wells in such fields for enhanced production, the industry should direct more resources towards developing wellbore stability models, with factors the compensate for the changes in formation stress patterns and rock strength arising from previous drilling and hydrocarbon production, for mature fields.

9. Conclusions

Wellbore instability is a rig time consuming incidence that increases the cost of drilling and field development; leading to a total loss of the well in severe cases.

Wellbore instability can occur during drilling and well completion activities. The causes of instability are: mechanical failure of the rock formation, interaction of drilling fluid with drilled formations, thermal interaction between wellbore fluid and formation and inappropriate drilling practices.

Mechanical earth models can be used to predict the possibility of instability problems in sections of the wellbore and to define the boundary conditions for maintaining stability.

The consequences of wellbore instability during drilling can spread to well completion; affecting the quality of cementing and consequently, well integrity.

Sealing agents and consolidation additives in drilling fluids have positive effects on wellbore stability.

In all drilling operations, the crew should make efforts to regulate formation exposure time to drilling fluid given that instabilty is a time dependent process. In addition to this, the drilling parameters should be regulated to optimize not just the rate of penetration but to ensure a stable wellbore.

All drilling projects should include characterization of the dominant shale in the field given that about 75% of drilled formation is shale and about 90% of instability problems occur in shale. Choosing drilling fluid components and parameters, wellbore parameters and drilling practices based on knowledge from geomechanical studies of the field in combination with equipment that provide real time information of the nature of the formation being drilled can help achieve stability in a proposed well.

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