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A Comprehensive Review of Wellbore Breathing

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A Comprehensive Review of Wellbore Breathing

by

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Dedication

This thesis is dedicated to my wife, Rebecca, as well as to my parents, Kevin and Gayle. I would also like to dedicate this work to the rest of my family, my friends, and the colleagues who encouraged me to pursue graduate school, both in industry and academia.

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I would like to first express my upmost appreciation to the petroleum engineering department at the University of Texas at Austin for the opportunity to pursue graduate studies here. My experiences here have been enlightening and rewarding, both in terms of course work and research, and these experiences will extremely useful going forward in my career.

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Abstract

A Comprehensive Review of Wellbore Breathing

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The University of Texas at Austin, 2015

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Wellbore breathing is a common occurrence during drilling operations, but the downhole mechanism and how it manifests itself in surface and subsurface processes, is not well understood. Wellbore breathing events often result in a drilling fluid gain at surface and are misidentified as a kick, resulting in unneeded shut in periods and associated non-productive time (NPT). Further, misidentification of wellbore breathing as underbalance often results in increases in mud weight, which only exacerbates the problem and may cause lost circulation.

This work focuses on characterization of the wellbore breathing phenomenon in practical contexts of the pressure, volume, temperature, and time behavior of the components involved in the surface and subsurface system. This was accomplished through the examination of case studies published in literature to develop a comprehensive review of common experiences and incidents, as well as the operational responses to these. Methods for identification, differentiation from kicks and underbalance, mitigation and prevention of wellbore breathing are proposed, in addition to operational procedures for safe continuance of drilling operations. The coupled nature of pressure, temperate, and

volume, as they pertain to wellbore breathing, are analyzed in detail in order to quantify their effects and how they can inhibit identification of wellbore breathing.

This research also proposes adaptation of the hydraulic fracturing pump-in flowback test interpretation developed by Plahn, Nolte, and Miska (1997) for the interpretation of wellbore breathing events and estimation of the minimum horizontal stress. This work presents estimates of the minimum horizontal stress for fractured zones in five wells using PWD data recorded during wellbore breathing events, which was obtained from literature. These estimates were verified qualitatively, when possible, by comparing across multiple connections and with available LOT data.

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Chapter 1: Introduction

1.1 Motivation

During conventional drilling operations, the density of the drilling fluid must be maintained at a high enough level to provide a greater hydrostatic pressure than both the pore pressure and collapse pressure of the formation being drilled. If the wellbore pressure falls below this threshold, a formation fluid influx, known as a kick, will occur and result in a well control event. Kicks are relatively routine and if recognized quickly, can be safely circulated out of the well in accordance with well control procedures. However, if a kick is not recognized, it can lead to a blowout and endanger the lives of everyone at the well site. Because of this danger, well control is of the upmost importance and takes precedent over all other well site activity.

Conversely, there is also an upper limit to the mud weight that can be employed while drilling, which is known as the fracture pressure. If the downhole pressure exceeds the fracture pressure, fractures will be initiated in the wellbore wall resulting in drilling fluid losses. This process is known as lost circulation. Lost circulation has been a leading cause of non-productive time (NPT) in the deepwater Gulf of Mexico over the last decade (van Oort, 2011). In deepwater settings where the spread rates on rigs often exceed one million dollars per day, NPT due to lost circulation can become extremely costly. Additionally, the drilling fluid systems in use today are highly engineered and losses of large fluid volumes adds incremental costs.

The difference between the formation pore pressure and fracture pressure is known as the mud weight window and a primary goal of the drilling operation is to maintain the mud weight within this range throughout the course of a well. One challenge in maintaining the mud weight within the drilling window, is the difference in the effective mud weight between circulating conditions and static conditions. During circulating conditions, frictional losses in the annulus lead to an increase in the effective mud weight of 0.1 to 0.5 pound per gallon (ppg) compared to the static conditions. During conventional drilling operations, the well is circulated while drilling ahead and the pumps are shut off to make each connection. Therefore, this fluctuation occurs every 90 or 120 feet, depending on the rig design, throughout the course of a well. This has commonly resulted in wellbore pressures that exceed the fracture pressure while drilling and are below the fracture pressure while making connections. The effective result of this, known as wellbore breathing, is fluid losses while drilling as mud flows into the opening fractures and fluid gains during connections as the fractures close and force mud back into the wellbore.

Wellbore breathing presents significant operational problems primarily because of the fluid flow into the wellbore during connections. This will register as a pit gain at surface and is often misidentified as a kick. The typical response to a kick is to raise the mud weight, but in the case of wellbore breathing, an increase in mud weight will only exacerbate the problem. The increased mud weight will cause the fractures to be propagated further, either worsening the breathing affect or breaking down the formation and causing large fluid losses. This scenario has played out numerous times during deepwater drilling operations, resulting in significant non-productive time and even complete loss of the well in extreme cases (Ashley, 2000). While there have been several wellbore breathing case studies published; the complex, highly coupled, and time dependent processes responsible and how these processes manifest themselves both downhole and at the surface, have not been examined together and in detail.

The primary objective of this thesis is to provide a comprehensive review of wellbore breathing, the mechanisms responsible for it, and how it can be identified through both surface and subsurface processes, or “signals”. This work focuses on explaining and detailing commonly encountered wellbore breathing scenarios in contexts of the pressure, volume, temperature, and time behavior of the involved surface and subsurface system. Additionally, there is significant ambiguity surrounding the terms, acronyms, and nomenclature pertaining to drilling operations and wellbore breathing specifically. This thesis work also defines and explains much of this terminology in both a technical and operational sense as it will be beneficial to the industry and academia alike.

1.2 Thesis Organization

This thesis consists of six chapters. Chapter 1 is composed of the introduction. Chapter 2 consists of a literature review of the past and present understandings of wellbore breathing and a review of the nomenclature, terms, and acronyms pertaining to wellbore breathing and drilling operations in general. Chapter 3 focuses on wellbore breathing case studies published in literature. Chapter 4 details methods for identification, mitigation, and prevention of wellbore breathing in addition to in addition to recommendations for safely continuing operations for wells experiencing wellbore breathing. Chapter 5 covers methods for inferring the in-situ minimum horizontal stress during breathing events and the theoretical background these methods are based on. Finally, Chapter 6 states the conclusions and recommendations for this thesis.

Chapter 2: Literature Review

2.1 Wellbore Breathing Past and Present Understandings

Wellbore breathing is a phenomenon that has been experienced from time to time on the drill floor over the decades and has been the subject of much debate as to the actual mechanism occurring downhole. Wellbore breathing was initially explained to be plastic deformation of wet shales or “shale charging” (Gill, 1986), later proposed to be caused by pressure, density, temperature behavior of drilling fluids downhole (Babu, 1993, 1997), and later hypothesized as the opening and closing of induced downhole fractures due to thermal affects (Maury and Idelovici, 1995). The hypothesis that opening and closing of downhole fractures, both induced and natural, due to pressure fluctuations between circulating and static conditions was then proposed (Tare et al., 2001) and has become widely accepted within the industry as the primary mechanism behind wellbore breathing.

2.1.1 Plastic Deformation of Shales

Wellbore breathing was initially termed wellbore ballooning when published and explained as the expansion of the wellbore, like a balloon, caused by long sections of wet plastic shales deforming plastically under the increased annular pressure during circulation (Gill, 1986). The graphic in Figure 2.1 below, is representative of the downhole process described by Gill. On the left side of the figure, the shale formation is plastically deformed due to a wellbore pressure significantly higher than the pore pressure when the well is in static conditions. On the right side of the figure, ECD due to circulation increases the amount of overbalance and deforms the shale hole section further resulting in an apparent fluid loss at surface. When circulation is stopped, the excess overbalance due to ECD is removed and the formation returns to a shape similar to that seen in the left figure, resulting in an apparent fluid gain at surface.

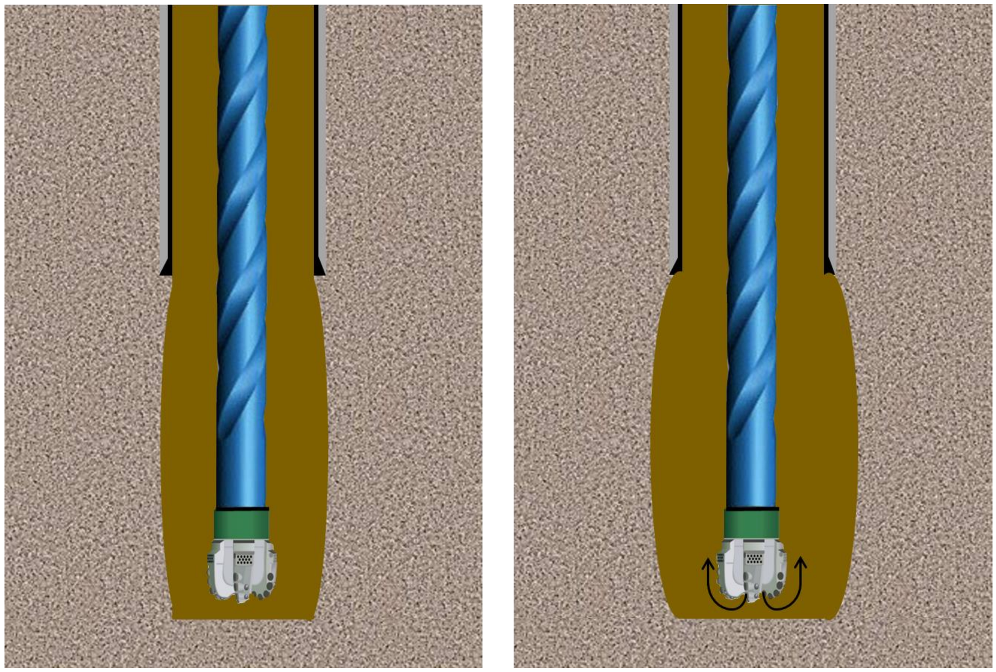

Figure 2.1: Left is shale deformation at static conditions, right is increased shale deformation while circulating (Drill bit and collars graphics from drillingformulas.com)

Supporting the plastic deformation of shales hypothesis, Gill cites wells which were drilled near each other, with significantly different mud weights, and experienced what were perceived to be vastly different pore pressure regimes as evidence that shale sections were being “super charged” to higher pore pressures by the higher mud weight. Additionally, Gill cites gravel size pieces of shale getting blown through a 3/8” choke holding 5,000 psi of back pressure on a well as evidence that shales behave plastically when subjected to high pressures. At the time, this hypothesis sparked significant debate within the industry and resulted in both industry and academic interest towards wellbore breathing and identification of the underlying mechanism causing it. . The hypothesis that shales were behaving plastically downhole has been disproven due to a lack of shale rocks exhibiting this behavior in experiments. Additionally, finite element modeling and analysis has shown that elastic deformation of the borehole, due to the increased pressure caused by the ECD, would contribute a volume change of only 1.5 barrels for extremely soft rocks, with a Young's modulus of 58,000 psi (Helstrup et al., 2001). While elastic deformation of the wellbore may be a contributing factor to wellbore breathing events, these gains and losses are often tens to hundreds of barrels in size, indicating that elastic wellbore deformation is not the primary mechanism.

2.1.2 Pressure-Density-Temperature Behavior of Drilling Fluid

Pressure, density, temperature behavior of muds was also proposed as an explanation for wellbore breathing events. Babu (1997) determined that after circulation is stopped, the drilling fluid in the wellbore will expand, between 11.1 and 35 bbls for a 17,500 ft well, as it warms to the geothermal gradient along its depth. While this expansion is realistic, warming of the mud to cause the expansion is a slow and gradual process that takes between 4 and 9 hours for half the expansion to occur (Babu, 1997). Because breathing events typically occur over the course of minutes rather than hours, the temperature change of a mud column after circulation has stopped can be ruled out as a cause of wellbore breathing.

2.1.3 Opening and Closing of Induced Fractures due to Thermal Effects

Maury and Idelovici (1995) published the first work attributing wellbore breathing to the opening and closing of induced fractures downhole. The work consisted of a relatively unique North Sea case study where a heat exchanger was used at surface to cool the oil based mud (OBM) in order to keep it below the flash point. This case study will be examined in detail later, but throughout the case study, wellbore breathing was experienced and subsequent increases in mud weight resulted in increased flow during flow checks and increased gas cuts at surface. Maury and Idelovici (1995) attributed this to:

- Fracture initiation caused by cooling of the formation during circulation and a subsequent reduction in its strength.
- Further fracture propagation due to continued cooling while circulating coupled with increased mud weights.
- Instantaneous mechanical decompression of the well and fractures partially closing when circulation is stopped due to loss of ECD, but this was thought to occur too quickly to be recorded during flow checks.
- Flow back during flow checks and trips caused by thermally induced fracture closure as the mud system and surrounding formation warmed and the effective fracture gradient increased.

The explanation of wellbore breathing as a thermally driven phenomenon is particular to the unique set of circumstances on this well, but poses important questions about the role of the thermal regimes and induced fractures in wellbore breathing.

2.1.4 Opening and Closing of Fractures, Induced and Natural

Present day understanding of wellbore breathing is that it is caused by fractures opening and closing due to downhole pressure fluctuations between static conditions and circulating conditions. While this had been proposed in response to Gill's hypothesis (Bowman, 1989) and (Holbrook, 1989), implementation of pressure-while-drilling (PWD) tools in the late 1990's provided downhole pressure measurements that supported opening and closing of fractures as the primary mechanism responsible for breathing (Ward and Clark, 1998). Tare, Whitfill, and Mody (2001) explained that wellbore breathing was primarily due to opening and closing of fractures, both induced and natural, and stated that the geologic setting, well trajectory, and operational parameters contributed to the process. Their work cited two Gulf of Mexico wells that experienced wellbore breathing and the borehole analysis results from those wells which indicated that fractures were responsible for the wellbore breathing events. Figure 2.2 below displays a simplified graphic of the idealized fracture opening and closing process during wellbore breathing.

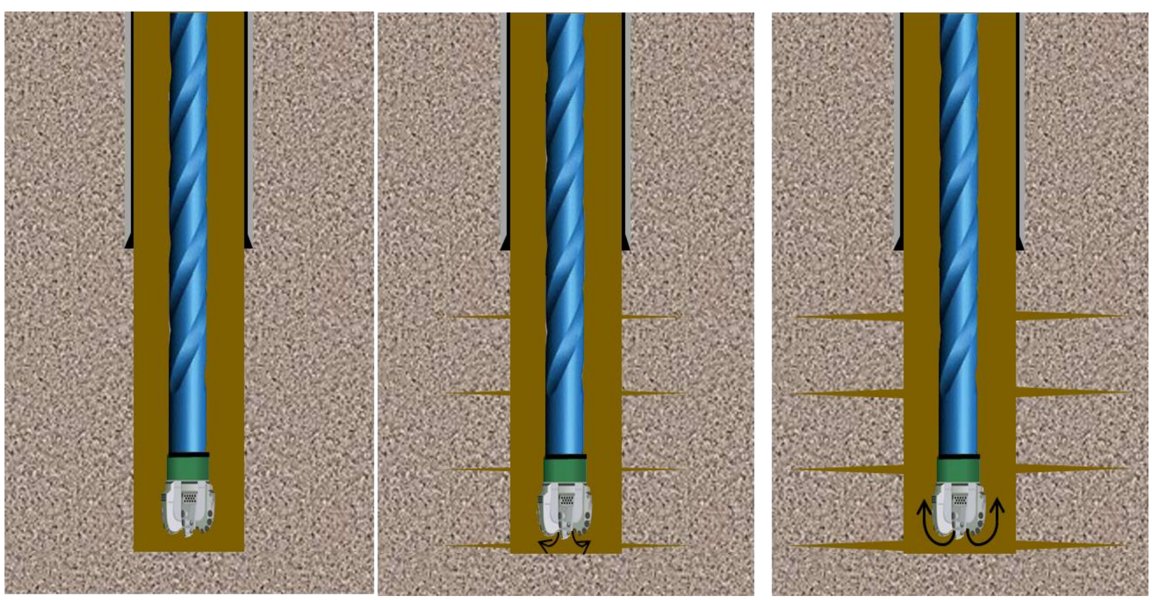

Figure 2.2: Graphic depicting the idealized fracture opening and closing process (Bit and drill collar graphics from drillingformulas.com)

On the left, the well is in static conditions and there are either no fractures in the wellbore walls, or they are all closed. In the center, the pumps are being staged up to the circulating rate, raising the wellbore pressure above the fracture pressure and either initiating fractures, or opening already present fractures. On the right, the pumps are at the full circulating rate and drilling has commenced resulting in a higher wellbore pressure and pushing more fluid into the fractures, possibly propagating them. In the time sequence this occurs in drilling operations, from left to right, the result is a net loss in the pits at surface. Once the stand is drilled down, the order of these events is reversed as drilling stops and the pumps are shut down for a connection. The wellbore pressure is reduced and the fractures close, forcing fluid back into the wellbore and causing an apparent pit gain at surface.

2.2 Definition of Terms and Nomenclature

This section will delve into some of the terms, acronyms, and nomenclature typically used in relation to processes that occur in and around the wellbore during drilling operations. It will focus on both technical and operational definitions of these terms and how these are interrelated.

2.2.1 Wellbore Integrity Tests

Wellbore integrity tests are used during the course of drilling operations to determine the strength of a formation and to verify pressure integrity of the previous casing string and cement job. The typical operational events immediately preceding a formation integrity test are: complete drilling of a hole-section, set and cement casing string, drill out casing shoe and 10-20 feet of new formation (Zoback, 2007), and close the BOP. Wellbore integrity test results are extremely important and will be used to make decisions concerning mud weight, kick tolerance, and well design during the subsequent hole section (van Oort and Vargo, 2007). There are multiple variations of formation integrity tests including LOT, LT, XLOT, and pump-in flowback tests, all of which will be detailed here

2.2.1.1 Leak Off Test

A typical pressure versus time and volume plot during a leak off test (LOT) is shown in Figure 2.3. As drilling fluid is initially pumped into the wellbore, the pressure typically displays a linear relationship with the volume of fluid pumped. At point 2, known as the fracture initiation pressure (FIP), the pressure begins to depart from its linear relationship with the volume pumped. Fluid continues to be pumped into the wellbore and pressure increases until point 3, when the mud pumps are shut down and fluid is no longer being pumped into the wellbore. The Pump-stop Pressure (PSP), point 3 in figure 2.3, is the maximum pressure recorded in a LOT. The pressure immediately drops to point 4, the Instantaneous Shut-in Pressure (ISIP). The pressure then decreases as drilling fluid leaks off into the formation or the pressure is bled off at the BOP. Additionally, a LOT is occasionally stopped prior to reaching the FIP. This is known as a Formation Integrity Test (FIT) and the pumps are stopped at point 1, the limit pressure (LP), while the pressure is still displaying a linear relationship with the volume pumped.

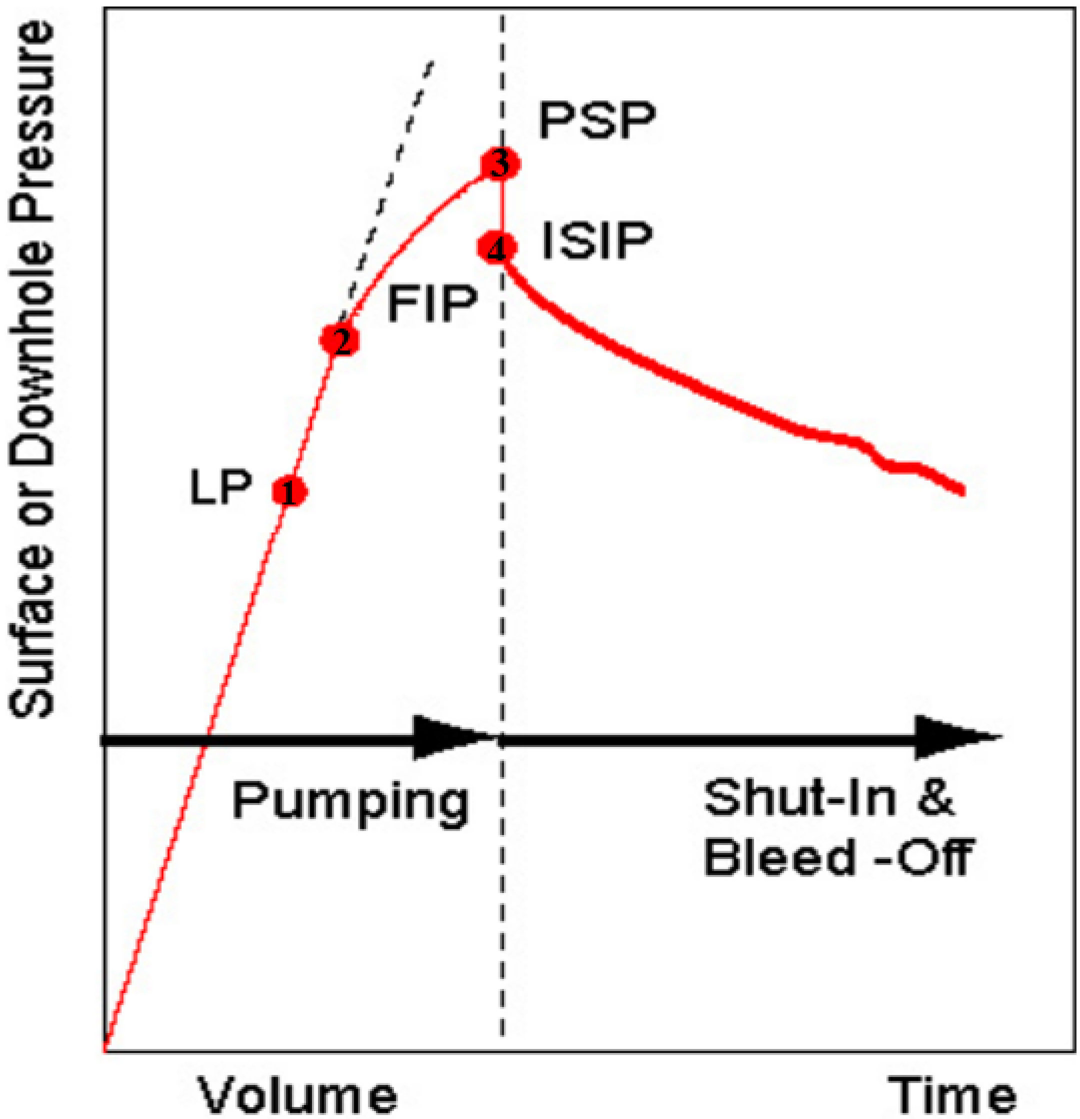

Figure 2.3: LOT plot (Modified after van Oort and Vargo, 2007)

2.2.1.2 Extended Leak Off Test

An example of a pressure versus time plot during an extended leak off test (XLOT) is shown in Figure 2.4. A XLOT is similar to a LOT, but fluid is pumped into the wellbore for an extended period rather than shutting the pumps down directly after the FIP has been reached. As fluid is pumped into the wellbore beyond the FIP, the pressure typically increases until the uncontrolled fracture pressure (UFP), also commonly referred to as the formation breakdown pressure (FBP), has been reached. Beyond the UFP, fluid is pumped into the wellbore at the same constant rate and the pressure typically decreases to a relatively constant value, the fracture propagation pressure (FPP) or point 4 in Figure 2.4. After the FPP has been reached, the mud pumps are shut off and the pressure immediately drops to the ISIP. The pressure then decreases as the fluid leaks off into the formation. A point of inflection in the pressure vs. time curve during the shut-in period indicates the fracture closure pressure (FCP). This is denoted in figure 2.3 with a dashed circle at the intersection of the two dashed lines.

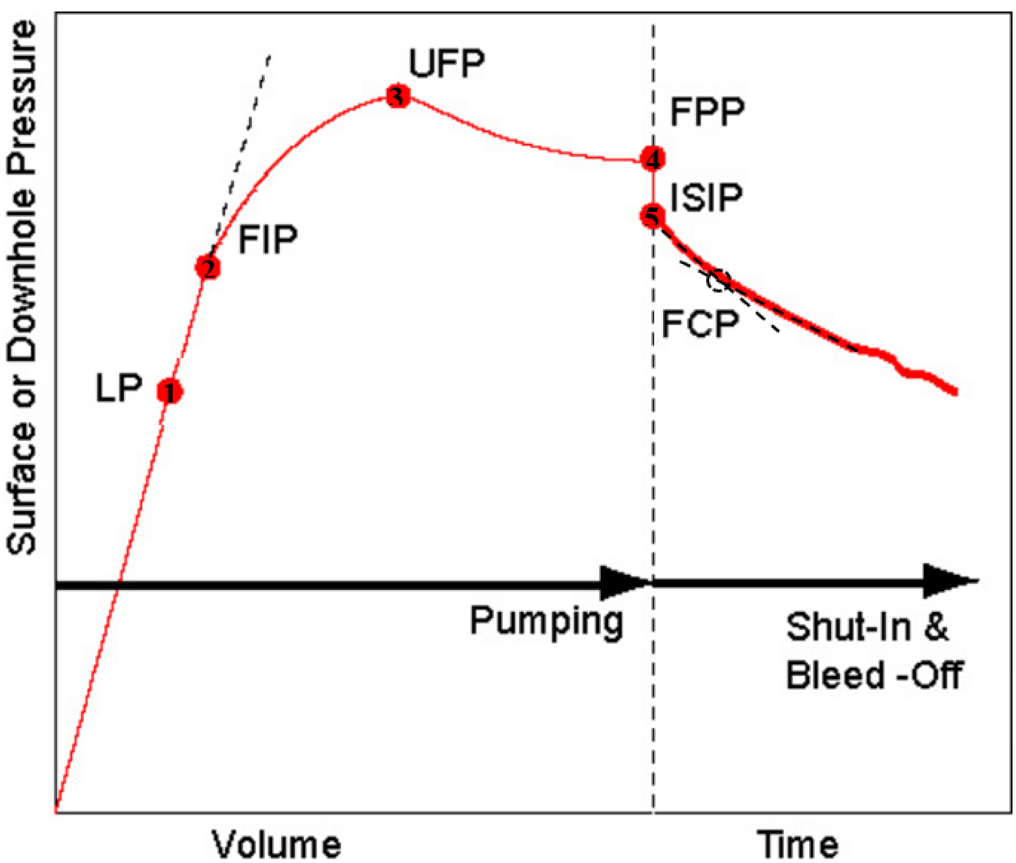

Figure 2.4: XLOT Plot (Modified after van Oort and Vargo, 2007)

2.2.1.3 Pump-in Flow-back Test

A typical plot for a pump-in flow-back test, or XLOT with flow-back, is shown in Figure 2.5. The test is identical to the XLOT described above, but the well is opened up and allowed to flow-back after the pumps have been shut down. The FCP can be identified by identifying the inflection point on the pressure versus time plot, which is marked as point 7 in Figure 2.5. The FCP can also be identified by locating the inflection point on a pressure versus volume plot during the flow-back portion of the test.

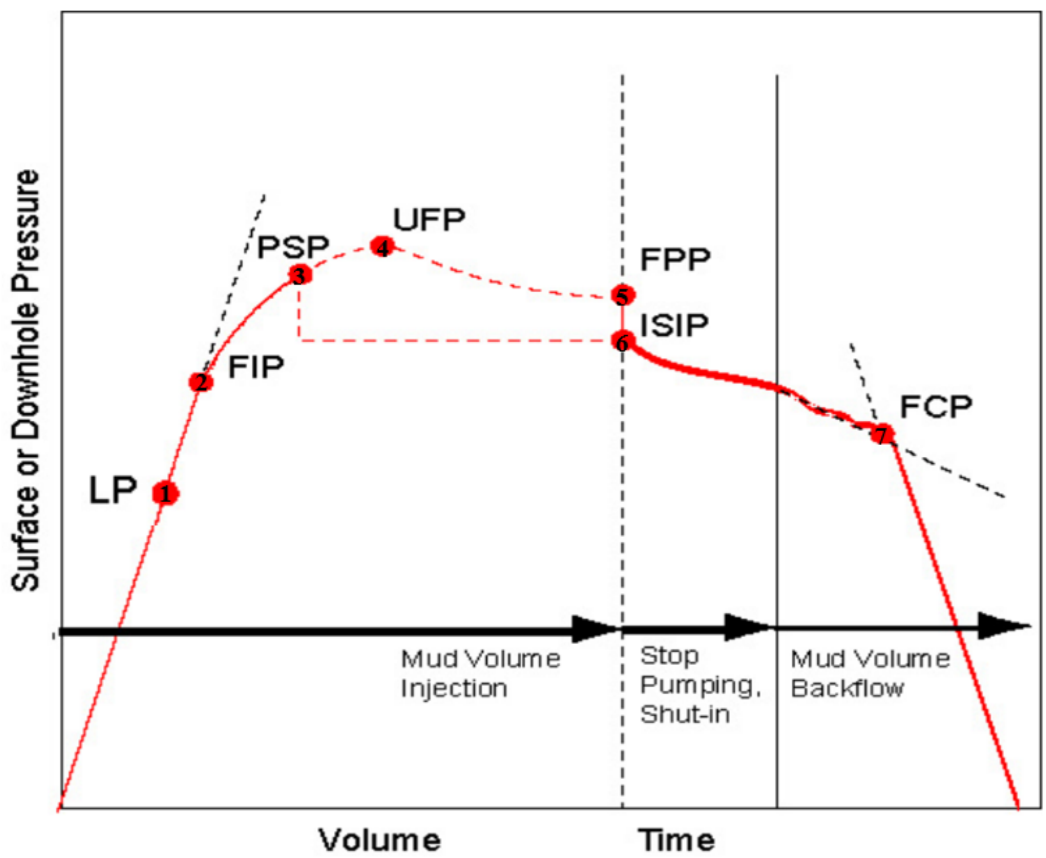

Figure 2.5: Pump-in Flow-back Test Plot (Modified after van Oort and Vargo, 2007)

2.2.1.4 Formation Integrity Test

A formation integrity test (FIT) is similar to a LOT, but the test is stopped prior to the pressure volume relationship departing from linearity. Limit tests are designed to test the cement strength in the shoe and are typically stopped at a pressure believed to provide a large enough drilling window to reach the next casing point. They are typically run in areas where past wells have been drilled and the minimum horizontal stress is relatively well understood. The reasoning for stopping the test early, in comparison with a LOT, is the desire to limit the damage to wellbore integrity that occurs when the pressure exceeds the FIP and the formation is fractured. FIT's are also commonly called Jug Tests.

2.2.2 Wellbore Integrity Test Nomenclature

This section focuses on describing the physical process or processes behind the terms used in describing the pressure versus time and volume behavior during formation integrity tests.

2.2.2.1 Limit Pressure

The limit pressure is the highest pressure achieved during a limit test and occurs on the linear portion of the pressure versus volume LOT plot (van Oort and Vargo, 2007). The limit pressure is a predetermined pressure set by the drilling engineer and is not indicative of the actual fracture gradient other than to provide a minimum value. There are typically two different scenarios where a LOT is stopped at the LP rather than continuing to the FIP. First, if a well is being drilled in a mature field with a well understood fracture gradient; the LP will be set below the expected FIP to avoid fracturing the formation. Second, in a problematic well which has used contingency strings uphole, the LP may be set to a value that is believed to provide enough kick tolerance to reach the next casing point. Similar to the first, the desire is to stop the LOT before the fracture gradient has been reached. Initiating a fracture could narrow the mud weight window enough to require the casing string be set short of its desired depth and potentially inhibit the well from reaching total depth.

2.2.2.2 Fracture Initiation Pressure

The fracture initiation pressure (FIP) is defined as the point where the pressure versus volume plot departs from linearity. The exact physical process causing this departure from linearity has been disputed in literature, but is believed to generally be related to the initiation of fractures in the formation (Edwards et al., 2002). The FIP is also commonly known as the leak off point (LOP).

2.2.2.3 Uncontrolled Fracture Pressure

The uncontrolled fracture pressure (UFP), commonly known as the fracture breakdown pressure (FBP), is the point on a XLOT plot when the pressure begins to decrease. The UFP is understood to be the point at which the energy stored within the fracture becomes large enough to overcome the hoop stress at the wellbore wall and the pressure loss along the length of the fracture and transmit enough pressure to the fracture tip to cause propagation out into the far field (van Oort and Vargo, 2007). The UFP can occur at the same point as the FIP, shown as (a) in Figure 2.6, or at a higher pressure than the FIP, shown as (b) in Figure 2.6.

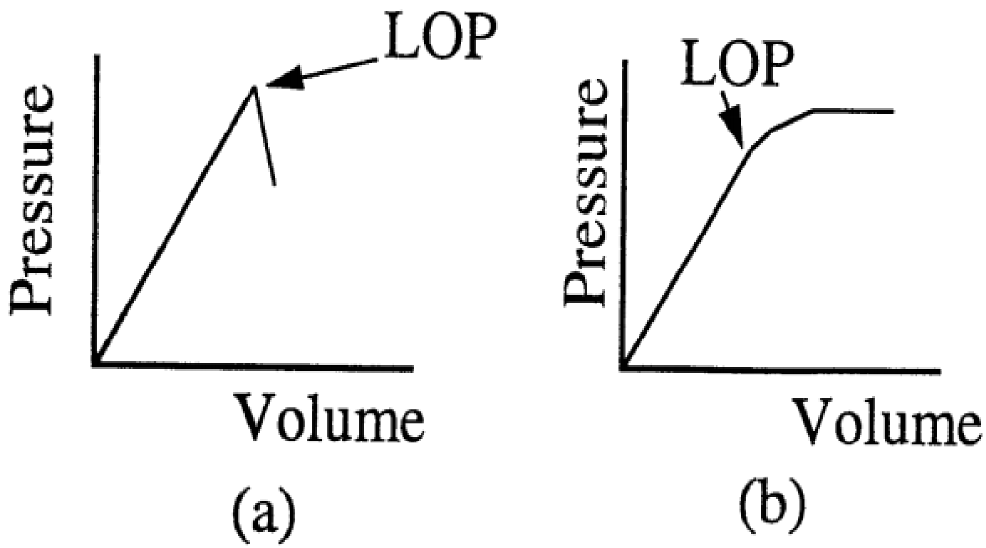

Figure 2.6: Typical LOT profiles (Edwards et al., 1998)

2.2.2.4 Fracture Propagation Pressure

The fracture propagation pressure (FPP) can be seen on a XLOT plot as the relatively stable pressure which is reached sometime after the UFP. An example of a XLOT plot with the FPP identified is shown in Figure 2.7. The FPP is understood to be the pressure required to propagate the fracture out into the far field in addition to any frictional losses caused by fluid flow inside the fracture (Zoback, 2007). Additionally, Edwards (1998) suggests that solids present within the drilling fluid can inhibit fluid flow to the tip of the fracture and subsequently increase the FPP. It is also worth noting that due to the frictional losses within the fracture, the value of the FPP is dependent on the rate at which fluid is being pumped into the well. Higher pump rates will typically result in a higher FPP value as the frictional losses along the fracture are proportionate to the flow rate through the fracture.

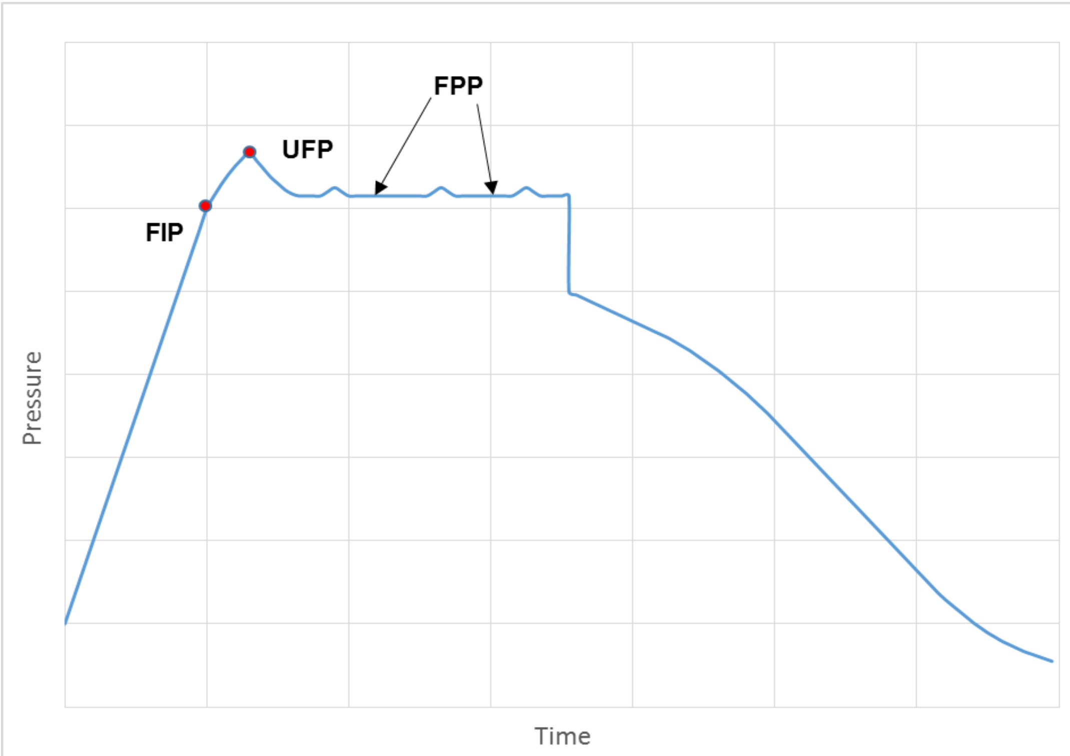

Figure 2.7: XLOT example plot with the FPP identified

2.2.2.5 Instantaneous Shut-in Pressure

The instantaneous shut-in pressure (ISIP) occurs during a wellbore integrity test after the fracture has been propagated and the pumps are shut down prior to the shut-in period. When the pumps are shut down, the pressure immediately drops to a lower value known as the ISIP. The drop in pressure is due to the loss of frictional effects in the fracture, wellbore, and mud pumps when the fluid flow is stopped. Since there is no longer pressure lost to friction along the fracture, there is a gradient within the fracture from a higher pressure near the wellbore to a lower pressure at the fracture tip. As this pressure gradient equalizes, the pressure at the fracture tip will actually rise and could potentially cause further fracture growth even though the pumps have been stopped. Completion engineers typically refer to the ISIP as the fracture pressure because this is the pressure which will reopen this fracture. A typical XLOT plot with the ISIP labeled is shown below in Figure 2.8.

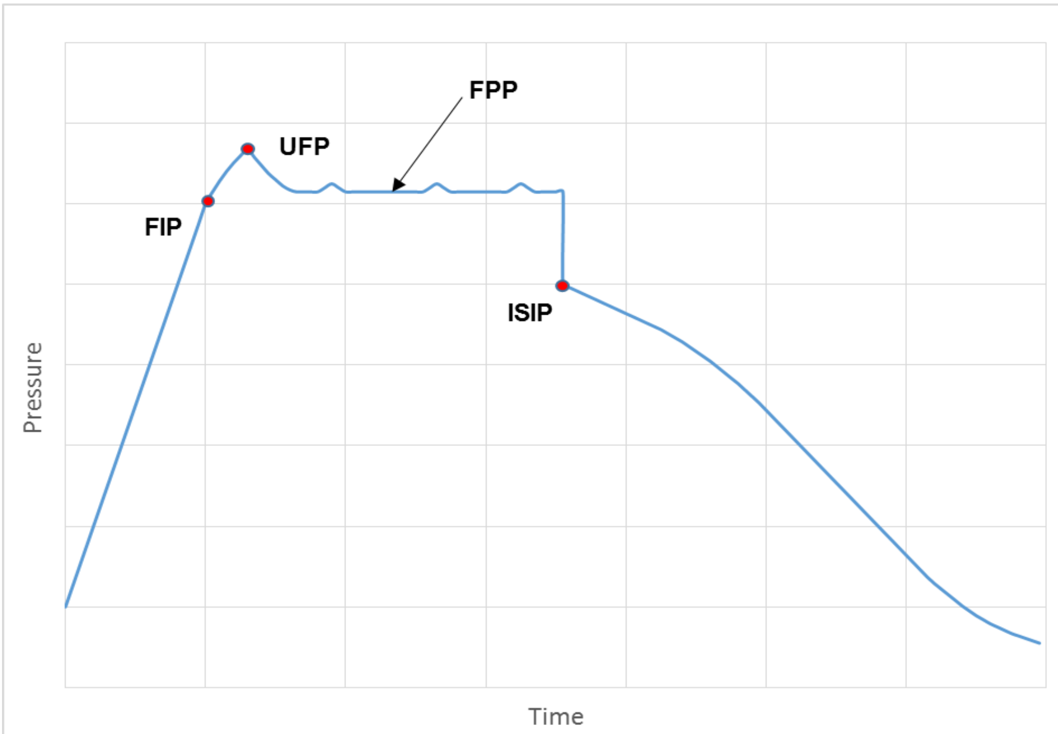

Figure 2.8: XLOT example plot with the ISIP identified

2.2.2.6 Fracture Closure Pressure

Fractures will tend to open in a plane perpendicular to the minimum in-situ earth stress because this is the path of least resistance for the fracture. Therefore, whenever the pressure inside the fracture decreases to a value below the minimum in-situ stress, the fracture will close mechanically; this pressure is the fracture closure pressure. Hydraulic closure typically does not occur until the pressure is reduced further, but mechanical closure is the value of importance to drilling engineers. The fracture closure pressure, if correctly interpreted through a wellbore integrity test, should provide an accurate estimate of the minimum horizontal stress. There are numerous methods for estimating the fracture closure pressure which will be covered in detail in later chapters. From an operational standpoint, the minimum horizontal stress is important because it governs the maximum mud weight that can be used while drilling a section. Because of this, accurate estimations of the fracture closure pressure and subsequently the minimum horizontal stress can be extremely valuable going forward in a drilling program.

2.2.2.7 Fluid Leak Off

Fluid leak off consists of the drilling fluid flowing into the formation and is recognized at the surface as a declining pressure during the shut-in portion of a formation integrity test. The rate of this flow is dependent on many things, but some of the primary drivers are formation permeability, mud cake thickness, mud cake permeability, fracture surface area, rock wettability, and capillary entry pressure. This leakoff process is most commonly described using Carter Leakoff theory (Carter, Howard, and Fast, 1957) which states that the flow rate of fluid leaking off into the formation is given by:

$$q_{leakoff} = \frac{2A_p C_L}{\sqrt{t-\tau_p}} \tag{2.1}$$

Where,

A_p = fracture surface area

τ_p = time when the fracture formed

C_L = leakoff coefficient

During a typical LOT, the pressure decline due to fluid leak off during the shut-in period exhibits a square root of time relationship, as shown in equation 2.1. The pressure can be plotted against the square root of time and the inflection point used to estimate the minimum horizontal stress.

2.2.3 Geologic and Geomechanic Terminology

This section will focus on some of the terms typically used during drilling operations that pertain to geomechanical processes downhole.

2.2.3.1 Principal Stresses

Compressive stresses are present throughout the earth and their magnitudes depend on depth, pore pressure, and any active geological process that acting in the area (Zoback, 2007). Additionally, using tensor transformation, these in situ stresses can be expressed in a principal coordinate system with three principal stresses as shown in Figure 2.9.

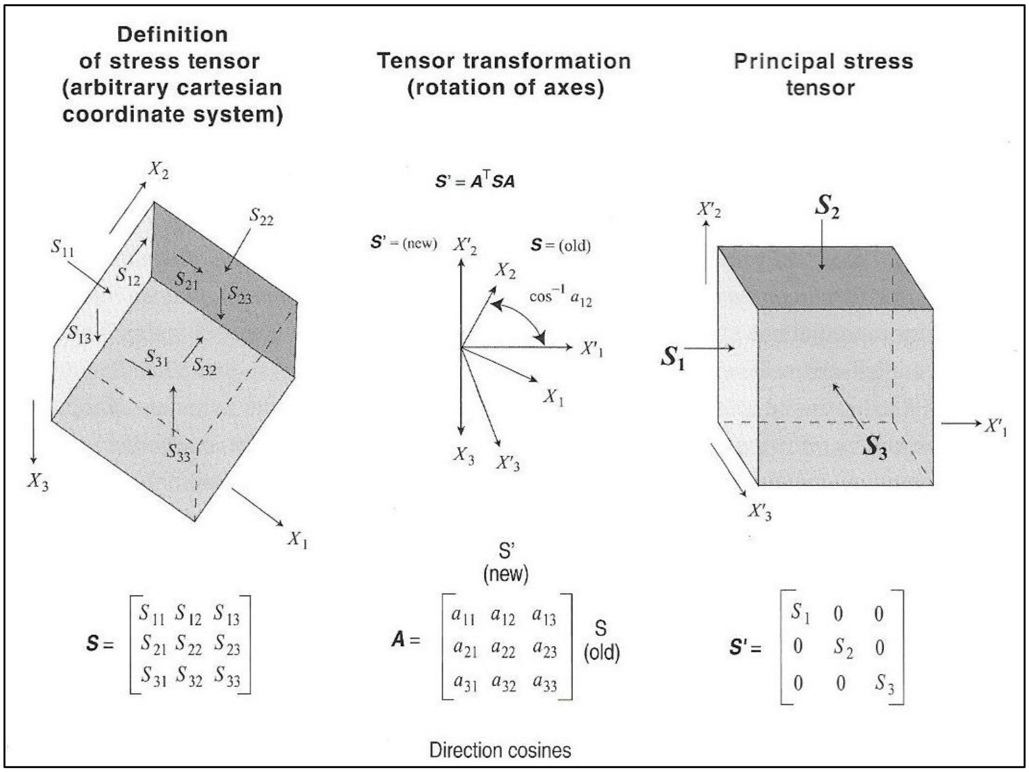

Figure 2.9: Stress tensor definition and transformation (Zoback, 2007; left graphic originally developed by Engelder and Leftwich, 1997)

Within the oil and gas industry, these principal stresses are typically described in terms of the vertical stress ($S_v\ or\ \sigma_v$), the maximum horizontal stress ($S_{Hmax}\ or\ \sigma_{Hmax}$), and the minimum horizontal stress ($S_{Hmin}\ or\ \sigma_{Hmin}$). More details will be provided in the further sections, but these stresses are vitally important because they govern wellbore stability and set the upper and lower bounds for the mud weight that can be used while drilling a given hole-section.

2.2.3.2 Far Field Stresses

Far field stresses are the stresses at a distance far enough from the wellbore, 2 – 3 wellbore radii, to be uninfluenced by the stress concentrations caused by the wellbore

(Zoback, 2007). In effect, these are the in-situ stresses within the formation and therefore are of much interest to petroleum engineers. The minimum horizontal stress is the primary stress of interest for drilling engineers as it governs the pressure required to open and propagate a fracture away from the wellbore. Because of this, determination of the minimum horizontal stress is a key aspect in drilling operations since it effectively sets the upper limit to the mud weight window.

2.2.3.3 Stress Regimes

The stress regimes within the earth are typically classified into three categories originally proposed by E.M. Anderson. These classifications are normal faulting, strike-slip faulting, and reverse faulting. In a normal faulting regime, the vertical stress is the largest principal stress. In a strike-slip faulting regime, the maximum horizontal stress is the largest with the minimum horizontal stress being the smallest and the vertical stress falling somewhere in between. In a reverse faulting regime, the vertical stress is the smallest with both horizontal stress being larger. The stress regimes are important as they govern the stresses that will be dominant at the wellbore wall and can provide insight into potential wellbore stability issues. Each of these classifications is displayed below in figure 2.10.

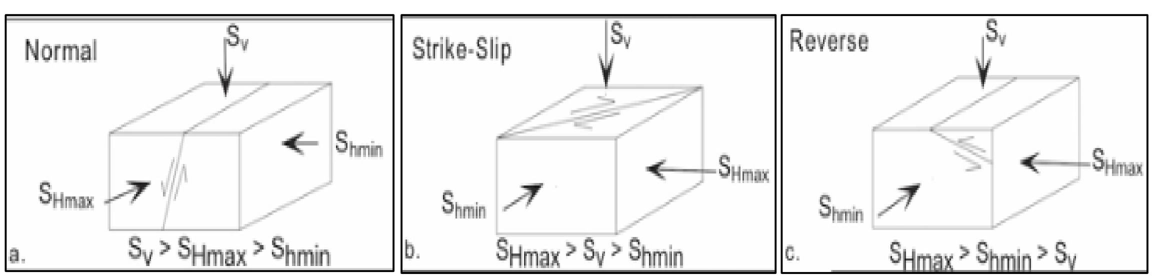

Figure 2.10: Stress regime classification scheme (Zoback, 2007)

2.2.3.4 Pore Pressure

Zoback (1998) explains that pore pressure is the scalar hydraulic potential acting within an interconnected pore space at depth; this is exemplified in Figure 2.11. Sedimentary rocks are not composed solely of grains and there are some spaces between these grains. The rocks within the earth typically have these voids, or pore spaces, filled with fluid. The pressure within these pore spaces, pore pressure, is described in comparison to the hydrostatic pressure at depth. The effective hydrostatic pressure at depth is known as normal pressure and any pore pressure exceeding this is considered overpressured while any pore pressure lower than normal pressure is considered underpressured.

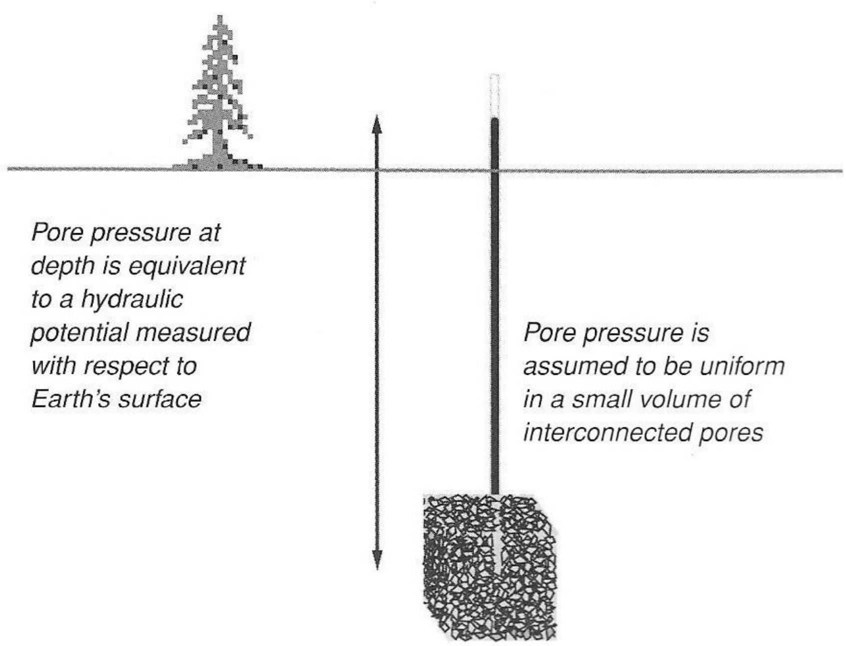

Figure 2.11: Pore pressure visualization (Zoback, 2007)

From an operations standpoint, a good understanding of pore pressure is extremely important to execution of safe drilling operations. During convention drilling operations, the primary method of well control is application of a downhole pressure greater than the pore pressure via a hydrostatic fluid column of ample density; this state is known as "overbalanced". If the pressure within the wellbore is allowed to fall below the pore pressure, an influx of formation fluids into the wellbore known as a "kick", can occur if the formation's permeability is high enough to allow flow; this state is called "underbalanced". In order to proactively increase the density of the drilling fluid prior to encountering higher pressure zones, accurate predrill pore pressure predictions are vital. Pore pressure predictions can be obtained via a seismic velocity to pore pressure transform (Sayers et al. 2006) and via data analog well data if available (Ziegler and Jones, 2014).

2.2.3.5 Fracture Gradient

The fracture gradient is the maximum wellbore pressure that can be applied while drilling and it is typically described in terms of mud weight (ppg). The fracture gradient is important in drilling operations as pressures exceeding the fracture gradient typically result in fluid losses. However, the fracture gradient is an ambiguous term that that has typically been interpreted differently by operations staff and engineers. Operationally, it is commonly associated with the FIP in a LOT because this is the pressure that the wellbore was able to actually withstand during the test. The increase in the FIP value compared to the minimum horizontal stress is due to the pressure required to initiate tensile failure at the wellbore wall and overcome the hoop stress in the near wellbore region; the hoop stress is detailed in section 2.2.3.2. Engineers typically relate the fracture gradient with the FCP because it is believed to be the best indicator of the minimum horizontal stress, but depending on the testing conditions during a LOT, the FIP or ISIP could also be indicative of the fracture gradient (Zoback, 2007). For the purposes of this paper, the term fracture gradient indicates the wellbore pressure which will initiate tensile failure in the near wellbore region and overcome the hoop stress, resulting in drilling fluid losses.

2.2.3.6 Collapse Pressure

The collapse pressure is the minimum wellbore pressure that is capable of maintaining wellbore stability. If the pressure in the wellbore is allowed to drop below this, shear failure will initiate at the wellbore wall causing wellbore breakout and potentially wellbore collapse. Operationally, this can manifest itself in issues such as tight hole or pack off while drilling and difficulty attaining a good cement bond behind a casing string (Mitchell and Miska, 2011). Early stages of wellbore breakout can be observed at surface when large cavings are seen at the shakers (Zoback, 2007).

2.2.3.7 Drilling Window

The drilling window is defined as the difference between maximum allowable annular wellbore pressure and the minimum allowable annular wellbore pressure. The upper limit to this window is set by the fracture gradient while the lower limit is set by the pore pressure or collapse pressure, whichever is greater. Typically, a pre drill pressure gradient plot similar to Figure 2.12 is created in order to quantify the estimated limits for down-hole annular pressures during drilling operations. The pressure gradient plot in Figure 2.12 is from the Shell Oil Ursa A-10 well in the Gulf of Mexico (Gradishar, Ugueto, and van Oort, 2013) and incorporates data points from LOT's and FIT's on offset wells.

Typically, the narrower a drilling window is, the more difficult a given well will be to drill. Wells with extremely narrow drilling windows often require complicated well designs, which incorporate many casing and liner strings, or unconventional drilling applications such as managed pressure drilling.

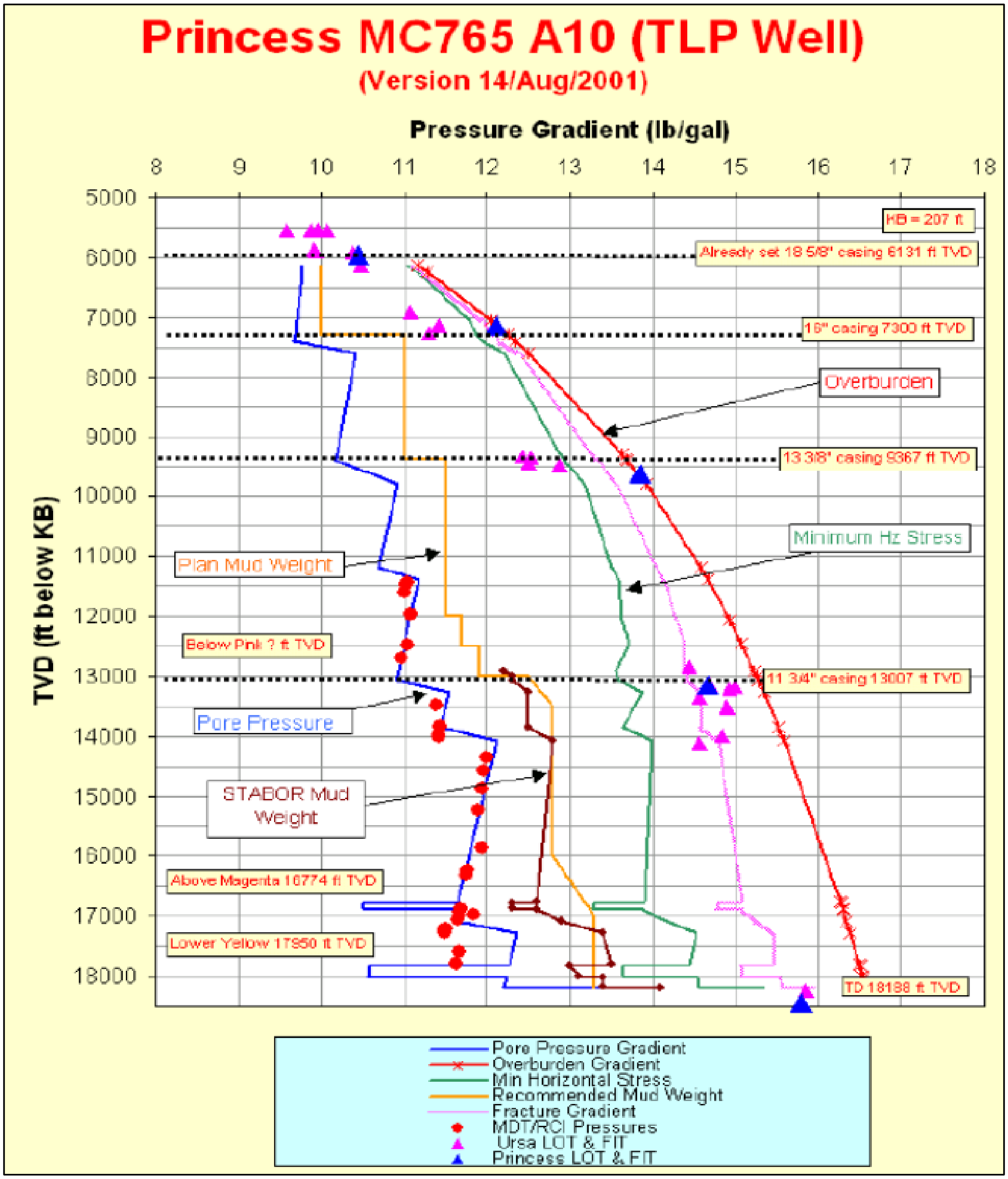

Figure 2.12: Estimated overburden, pore pressure, fracture, and minimum horizontal stress gradients (ppg) with proposed mud weight and LOT/FIT data (modified after Gradishar, Ugueto, and van Oort, 2013)

2.2.3.8 Rubble Zone

Rubble Zone is the term often used to describe the fractured rock or sediments directly adjacent to a massive salt body. Salt has a lower density than the sediments around it, 2.16 SG compared to 2.35-2.6, and creeps upward over time because of this (Dussealt et al., 2004). Some examples of salt structures are shown below in Figure 2.13 with potential rubble zones highlighted with red ellipses. Depending on the integrity of the adjacent rocks, the salt creep can create an adjacent highly fractured zone resulting in fluid losses while drilling or a "sheared" zone resulting in wellbore instability problems (Saleh, Williams, and Rizvi, 2013).

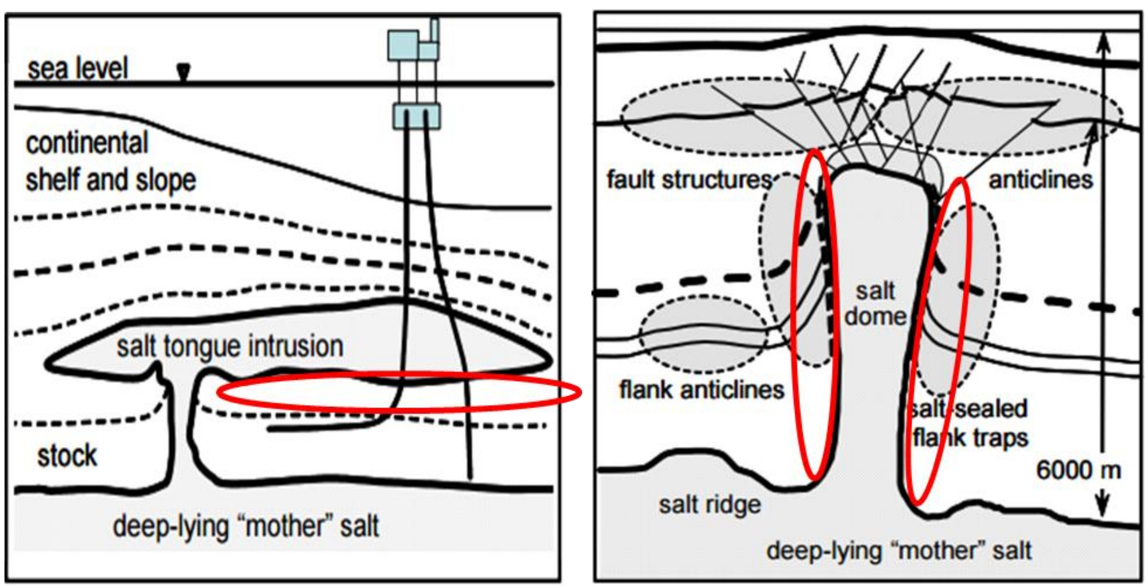

Figure 2.13: Drilling through salt tongue intrusion, salt dome with potential structural traps highlighted in gray (Modified after Dussealt et al., 2004)

2.2.3.9 Hoop Stress

Kirsch (1898) determined that stresses within a material become concentrated around a cylindrical opening because the void space cannot support the far-field stresses. This is known as the hoop stress. The hoop stress concentration around the wellbore result in the highest compressive stress in the direction of minimum horizontal stress and the lowest compressive stress in the direction of the maximum horizontal stress. Figure 2.14 display these hoop stress concentrations using two Kirsch solutions superimposed at a 90 degree angle from each other.

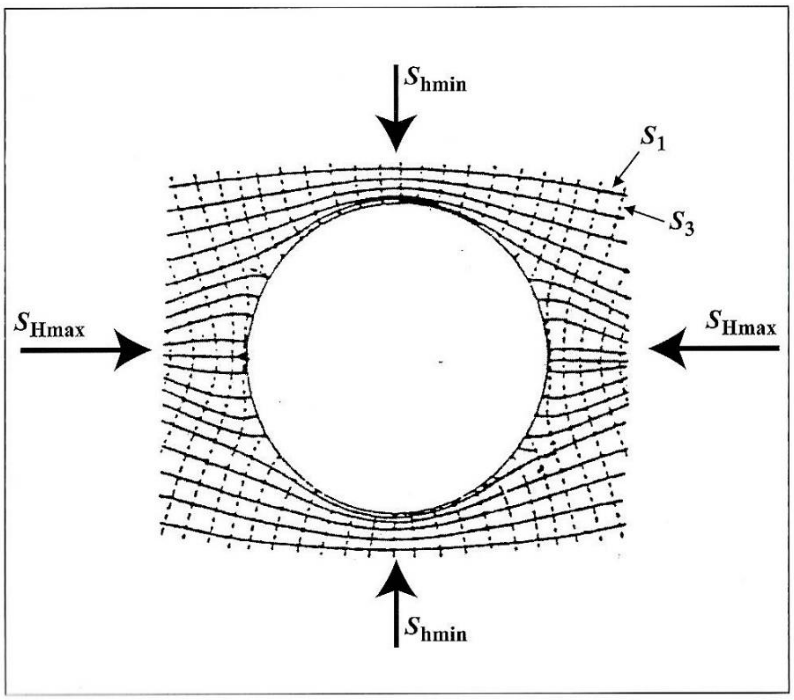

Figure 2.14: Stresses around a cylindrical opening within a bi-axial stress field (Zoback, 2007)

These stresses are governed by the Kirsch equations which are displayed below, simplified for just the stresses acting at the borehole wall (Zoback, 2007).

The effective hoop stress is:

$$\sigma_{\theta\theta} = S_{hmin} + S_{Hmax} - 2(S_{Hmax} - S_{hmin}) \cos 2\theta - 2P_p - \Delta P \tag{2.1}$$

The effective radial stress is:

$$\sigma_{rr} = \Delta P \tag{2.2}$$

Where,

$\Delta P =$ wellbore pressure – pore pressure

$P_p =$ pore pressure

$\theta =$ the angle measured from the azimuth of S_{Hmax}

Due to the smallest compressive stress being located at the azimuth of S_{Hmax} , fractures will initiate at this point and the wellbore pressure required to initiate these fractures is:

$$P_w = 3S_{hmin} - S_{Hmax} - P_p - T_o \tag{2.3}$$

Where,

$P_w =$ Wellbore Pressure

$T_o =$ Tensile strength of the rock

Additionally, since the drilling fluid pumped downhole is typically colder than the in-situ temperature, it is important to include a term for the thermal stress change when calculating the hoop stress. Including the term for the stress change due to thermal effects, provided by Fjaer et al., (2008), the wellbore pressure required to initiate fractures is given by:

$$P_w = 3S_{hmin} - S_{Hmax} - P_p - T_o + \frac{E}{1-\nu}\alpha_T(T_w - T_f) \qquad (2.4)$$

Where:

E = Young's Modulus

$\propto_t$ = linear thermal expansion coefficient

υ = Poisson's Ratio

T_f = Original formation temperature

T_w = Wellbore temperature

Since the fluid temperature within the wellbore is less than the in-situ formation temperature, the thermal stress term in equation 2.4 will become negative and result in a lowering of the pressure required to initiate a fracture at the wellbore wall.

2.2.4 Drilling Fluids Terminology and Nomenclature

This section focuses on some of the key terms pertaining to drilling fluids and the processes associated with them.

2.2.4.1 Equivalent Static Density (ESD)

The equivalent static density (ESD) is the equivalent fluid density, typically displayed in pounds per gallon, of the mud column in the well when all pumps are shut off, there is no movement of the drill string, and there is no backpressure being applied at the surface. It differs from the MW measured at surface due to temperature and pressure effects in the wellbore.

2.2.4.2 Equivalent Mud Weight

The equivalent mud weight (EMW) is the fluid density that would be required to provide an equivalent hydrostatic head to equal the bottom hole pressure being applied. During LOT's, the well is shut-in and fluid is pumped into the well to increase the annular pressure. The goal of a LOT is to test the cement job and determine the strength of the formation. Operationally, the results of these tests are typically expressed in pounds per gallon and referenced as the EMW, because the value is the highest mud weight that can be used while drilling the subsequent hole section without fracturing the well.

2.2.4.3 Equivalent Circulating Density

During drilling operations, circulating fluid causes frictional losses in the annulus which cause an increase in the pressure downhole. In addition to the pressure increase caused by frictional losses, large amounts of heavy rock cuttings suspended in the drilling fluid, rotation of the drill string, and vertical movement of the drill string can increase the pressure down hole. The equivalent circulating density (ECD) is the fluid density that would be required to provide an equivalent hydrostatic head equal to the bottom hole pressure being applied during the aforementioned operations including but not limited to circulating.

2.2.4.4 Mud Cake

During the course of drilling, particles within the drilling fluid create a thin low permeability layer along the wellbore wall called a mud cake (Mitchell and Miska, 2011). As some of the drilling fluid flows into the formation, it drives fines and other suspended particles onto the rock face. Because fluid flow into the rock is the primary driver, mud cake formation requires a permeable rock and some minimum of overbalance pressure (Jiao and Sharma, 1993).

Formation of a mud cake is beneficial for prevention of large fluid losses into permeable formations while drilling. Additionally, once the hydrocarbon reservoir has been reached, a filter cake can prevent drilling fluid infiltration of the reservoir and subsequent formation damage.

2.2.4.5 Cuttings Loading

As the wellbore is deepened through drilling, the rock cuttings are carried up through the annulus by the drillings fluid. Cuttings loading is the increase in the equivalent density of the mud column due to the heavier pieces of rock suspended in the drilling fluid. In scenarios with a narrow drilling window, cuttings loading can potentially increase the ECD above the minimum horizontal stress and cause lost circulation. In scenarios like this, operators often attempt to limit the amount of cuttings suspended in the annulus by drilling at a controlled rate or drilling short sections and pausing to circulate.

2.2.4.6 Barite Sag

During drilling operations, weighting agents, with barite being the most typical, are introduced into the drilling fluid in order to increase its density. Barite sag is the fluctuations in mud weight that occur due to downhole settling of the barite (Bern et al., 2000). Barite sag can occur both while the fluid column is static and in circulation. Barite sag in a static fluid column occurs due to poor gel strength of the drilling fluid while sag during circulation occurs due to low drilling fluid rheology (Gradishar, Ugueto, and van Oort, 2013). Barite sag can result in an uneven mud profile in the well and result in an influx if the heavier fluid falls below a high pressure zone. Additionally, if a large slug of higher density fluid has accumulated and is pumped up the hole, it may fracture the formation and cause lost circulation.

2.2.5 Lost Circulation Nomenclature

This section pertains to the terms and nomenclature commonly used to describe drilling fluid losses into permeable or hydraulically fractured formations during drilling operations. This process is commonly referred to as lost circulation. The term itself originated because drilling fluid returns to surface are reduced during these situations.

2.2.5.1 Uncontrolled Fracture Growth

Uncontrolled fracture growth occurs when the pressure in the wellbore rises to a point where it propagates fractures into the far field. This occurs as a result of the wellbore pressure exceeding the minimum horizontal stress, the hoop stress at the wellbore wall, and any pressure drop along the length of the fracture due to frictional effects. It is recognized at surface by significant fluid losses, on the order of tens to hundreds of barrels per hour, and typically requires changes in the current operating conditions to reduce or eliminate the losses. Some of these operational methods will be discussed in later sections, but the primary objective is to either reduce the wellbore pressure or plug the fracture. In some cases, the operator may continue to drill ahead even if losses have not been stopped because this is believed to be the best approach for reaching the next casing point. Due to the significant cost of oil based or synthetic based muds, the proposition of losing thousands of barrels of mud is an expensive endeavor.

2.2.5.2 Fracture Bridging

Fracture bridging is the process of plugging off a downhole fracture using some form of material introduced to the mud system at surface. The desired result is to inhibit further fracture growth and stop or at least reduce fluid losses. Depending on the size of the lost circulation material (LCM) added to the system and aperture of the fracture, this may occur at the fracture tip, somewhere along the fractures length, or in the opening of the fracture at the wellbore wall. There are several competing hypotheses as to the exact physics pertaining to fracture bridging and its ability to mitigate lost circulation events which will be discussed in further detail in the in later chapters.

2.2.5.3 Wellbore Strengthening

Wellbore strengthening is the process of increasing the upper bound of the mud weight window by creating and then plugging fractures in the formation being drilled. Wellbore strengthening has been a focus in recent years as deep water basins with narrow mud weight windows, such as the Gulf of Mexico, have been targeted. These narrow drilling windows have led to a significant number of lost circulation events resulting in large amounts of non-productive time (NPT) and its associated cost (van Oort et Al., 2009). As mentioned previously, there are several competing hypotheses as to the exact physics pertaining to wellbore strengthening. Graphics depicting each of these are shown below in Figure 2.15 and explained further in the following paragraph.

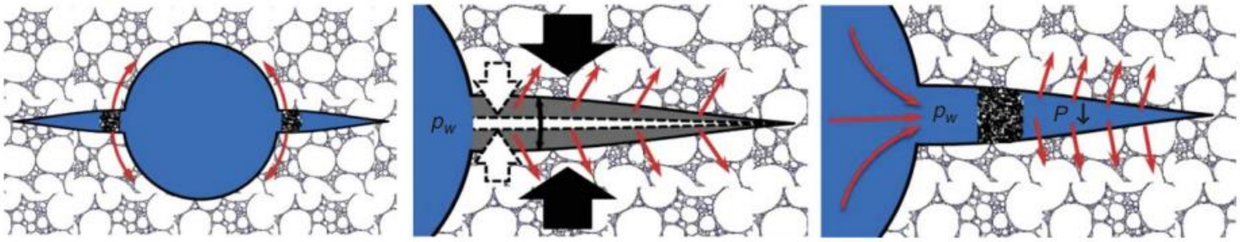

Figure 2.15: Differing hypotheses for lost circulation mitigation. From left to right, stress cage effect (Alberty and McLean, 2004), fracture-closure stress (Dupriest, 2005), and fracture-propagation resistance (Fuh, Boyd, and McGoffin, 1992)).

The stress cage concept, proposed by Alberty and McLean (2004), is based on placing high strength solids at or near the mouth of a fracture. As fluid leaks off into the formation, the fracture will begin to close and will be held partially open by the solids lodged at the fracture mouth. The prevention of the wellbore from returning to its initial state, is proposed to increase the hoop stress around the wellbore and subsequently increase the pressure needed to initiate future fractures.

The fracture closure stress concept, proposed by Dupriest (2005), is based on first bridging the fracture at some finite distance from the tip of the fracture in order to isolate the tip and subsequently forcing drilling fluid and solids into the fracture causing the fracture to widen. As the fluid leaks off into the formation, it results in a solids filled fracture. The width of this solids filled fracture is proposed to result in a larger fracture closure pressure, which will enable the well to be deepened with a higher ECD than previously possible.

The fracture-propagation resistance concept originated from the DEA-13 joint industry project in the late 1980's. The findings of this JIP were published in Morita, Black, and Fuh (1990), which proposed the theory of lost circulation pressure and the variables influencing this pressure. Fuh, Boyd, and McGoffin (1992) then proposed use of narrowly sized granular material as a means to isolate the fracture tip from the wellbore pressure, known as fracture-propagation resistance. This results in an increase in the wellbore pressure required to propagate the fracture, which allows the well to be deepened with a mud weight higher than would have otherwise been possible. Fuh, Boyd, and McGoffin (1992) presented two field cases where this theory was successfully applied and resulted in significantly higher fracture propagation pressures. Based on this fracture-propagation resistance concept, Van Oort et al. (2009) later proposed constant application of specifically sized particles while drilling as a means to constantly strengthen boreholes while drilling and presented field evidence supporting the effectiveness of this application. Table 2.1 below highlights some of the primary differences between the competing wellbore strengthening hypotheses explained in the prior paragraphs. The materials added to the fluid system during wellbore strengthening operations are known as wellbore strengthening materials (WSM).

	Stress Caging (SC)	**Fracture Closure Stress (FCS)**	**Fracture Propagation Resistance (FPR)**
Application Medium	Water-Based Pill	Water-Based Pill	Field Mud (SBM or OBM)
Application Technique	Hesitation Pill Squeeze	Hesitation Pill Squeeze	Continuous in Mud
Rock / Closure Stress Altered?	Yes	Yes	No
Fracture Tip Isolation Required?	No	Yes	Yes
High Fluid Loss Required	Yes	Yes	No
WSM Particle Strength	Important	Unimportant	Unimportant
WSM Particle Size	Important	Unimportant (400 µ used for most applications)	Important
WSM Particle Type	Important	Unimportant	Important

Table 2.1: Differences between wellbore strengthening hypotheses (Modified after van Oort et al., 2009)

2.2.5.4 Lost Circulation Material

Lost circulation material (LCM) consists of fibrous, flaky, or granular materials which are pumped downhole when fluid losses are occurring in an effort to bridge fractures and stop or decrease losses. Depending on the mechanism believed to be responsible for the fluid losses, differing types and sizes of LCM's may be used. In years past, LCM designations had often been unspecific and resulted in a multitude of different materials being pumped downhole that were available at the wellsite. Through work performed by a joint industry project in the mid 1980's, Drilling Engineering Association 13, it was determined that a large and uniform particle size could bridge fractures and inhibit further fracture propagation (Fuh et al. 1992). Later work identified particle size, particle size distribution, concentration, and shape as key attributes affecting material's suitability as a LCM and identified a combination of graphite and calcium carbonate specifically as a suggested LCM (Friedheim, Sanders, and Roberts, 2008). Further work also identified chemical gel systems as suitable for LCM and suggested use of a combination of base oil, gelling agent, initiator, reaction retarder, oil-wetting agent, and viscosifier to achieve this (Scorsone, Sanders, and Patel, 2009).

As shown by the references above, different combinations of materials and gel systems are capable of mitigating lost circulation events and can all be classified as LCM's. Furthermore, depending on the formation being drilled and other downhole variables, each of these has a proper application and is currently used by industry to combat lost circulation issues.

2.2.5.5 Fracture Healing

Fracture healing is a phenomenon occurring with water based muds (WBM) where repeat LOT's will result in the same FIP while repeat LOT's using oil based mud (OBM) or synthetic-oil based mud (SBM) typically result in a lower FIP value compared to the initial test. This phenomenon is believed to be a result of the inability of OBM and SBM to leak-off into the water-wet shales where casing shoes are typically set and LOT's are subsequently performed. Fluid leak-off for non-aqueous fluids is limited by interfacial tension and capillary entry pressures in water-wet rocks (Peters, 2012). Because of this, the non-aqueous fluid will remain in the fracture, preventing complete fracture closure, while a WBM will be able to leak off into the formation, allowing complete fracture closure (Ziegler and Jones, 2014). This manifests itself in LOT pressure responses because subsequent pressure increases will immediately be felt on the fracture face for non-aqueous fluids resulting in a lower FIP value than the original, which had to initiate or open the fracture. Figure 2.16 below shows a depiction of the differences in leak-off behavior and fracture closure with WBM and OBM or SBM.

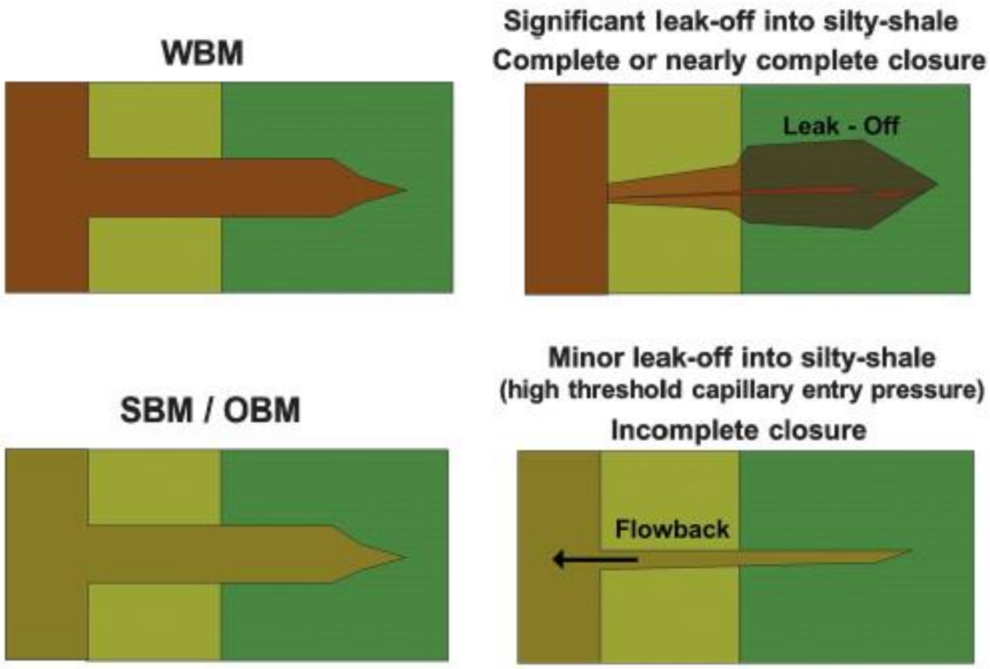

Figure 2.16: Interaction between WBM and OBM or SBM with a water-wet rock during fracture closure (Ziegler and Jones, 2014)

Additionally, fracture healing can also manifest itself during typical drilling operations. In a case where a fracture closed due to a reduction in pressure and fluid leak-off, circulating drilling fluid may build a filter cake over the fracture in the wellbore wall. This will provide an additional pressure barrier to reopening the fracture and may allow wellbore pressures to exceed the fracture closure pressure while drilling ahead without incurring losses.

2.2.5.6 Surge Pressures

Surge pressures are classified as sudden annular pressure increase due to operational activities. Surge pressures are important because the pressure spike could increase the wellbore pressure above the FIP and fracture the formation. Once this fracture has been initiated, the wellbore integrity has been compromised and will likely be weaker than it was prior. In a hole-section where the FIP exceeds the FPP, a pressure surge induced fracture may lead to fluid losses at a mud weight that had previously been used with no associated losses. Typical operational activities that may exert surge pressures if performed improperly include tripping drill pipe into the hole, running a casing or liner string, and wireline activities.

2.2.6 Formation Fluid Returns at Surface and Well Control Terminology

This section focuses on the terms and nomenclature surrounding formation fluid returns at surface and well control. It is extremely important content in the scope of this thesis because wellbore breathing is a type of well control event. In order to better understand and characterize the subsurface processes during a breathing event, it is important to understand how these processes manifest themselves through returns at surface. Last, in order to understand and avoid potential pitfalls and miscalculations related to wellbore breathing and well control, it is necessary to have a solid understanding of the fundamental well control processes which will be explained in this section.

2.2.6.1 Drill Gas

During the course of drilling operations, gas measurements will be taken at surface to monitor the amount of gas present in the drilling mud when it returns to surface. These gas measurements are displayed on the driller’s screen in the doghouse and have been commonly used over the years as a qualitative assessment of whether the well is in a state of overbalance, underbalance, or near-underbalanced (Alberty and Fink, 2014). Formations will be encountered which have hydrocarbons in their pore spaces and as the drill bit cuts away this formation, these hydrocarbons will be released into the drilling fluid and circulated to surface. When the formation being drilled has some gas within its pores, this will show up as a relatively low and stable gas reading at surface and is known as drill gas. The differentiation between drill gas and some of the other types of gas shows at surface is that the drill gas enters the wellbore while the hole is being deepened and fluid is being circulated. It can be verified as drill gas using the circulating flow rate and a simple volumetric calculation of the annular volume of the wellbore. Figure 2.17 below shows a typical mud circulation system with the equipment used to measure the gas cut, the gas trap and degasser, highlighted.

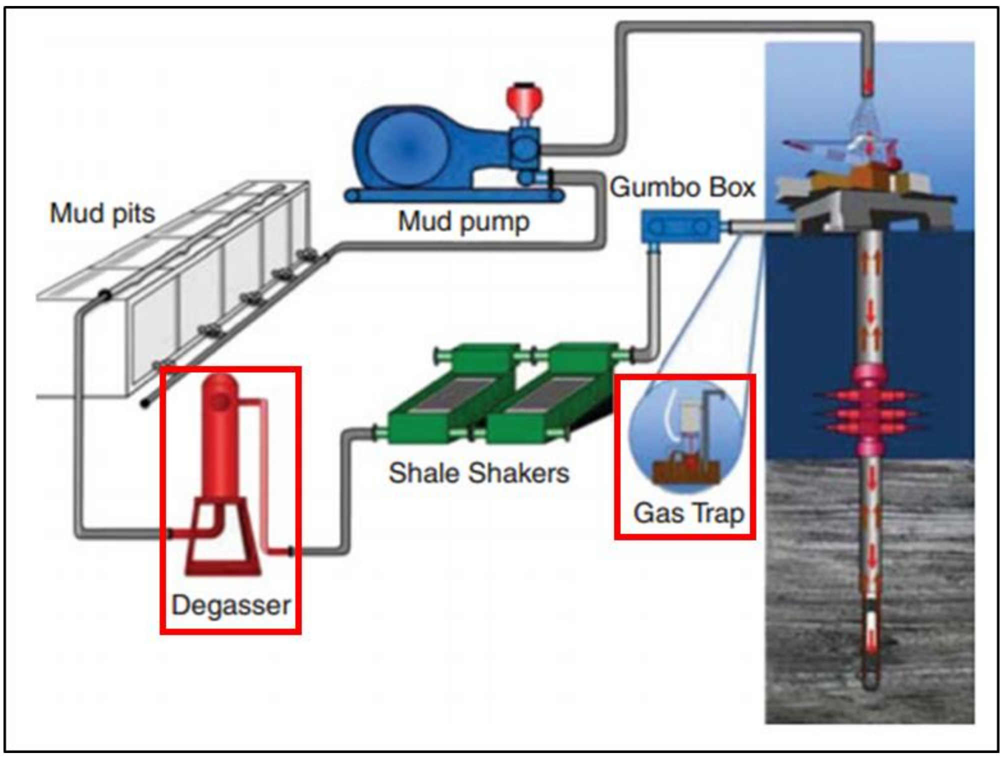

Figure 2.17: Typical mud circulation system with gas separation and measurement devices highlighted in red (Modified after Alberty and Fink, 2014)

Operationally, low and constant levels of drill gas is very common and has little significance other than to indicate that the formation being drilled contains some hydrocarbons. It does not require raising of the mud weight as the associated hydrocarbons would still enter the wellbore when the rock containing them is crushed and cut away. Situations where there are sudden increases in the drill gas cut should be approached with caution and would typically require a flow check to ensure that well is in still in an overbalance condition and not flowing. Drill gas measurements in this type of scenario serve as a second line of defense to identify influxes when a pit gain either did not occur or was missed. Last, these measurements are extremely useful when drilling with an OBM or SBM as gas is soluble in these. This is dangerous because a gas influx that occurs at a pressure above the mixture's bubble point may not register as a significant pit gain at surface.

2.2.6.2 Connection Gas

During conventional drilling operations, a stand of drill pipe (typically three, thirty foot joints depending on the rig) is typically used to continuously drill ninety feet prior to pausing to disconnect the top drive and add another stand of pipe to the drill string. During these connections, the mud pumps are shut down resulting in a static annular mud column and loss of ECD. Connection gas is the gas registered at surface when the volume of mud sitting in the open hole during the connection returns to surface once circulation has resumed. It is important to differentiate between connection gas and drill gas because the loss of ECD during connections reduces the bottom hole pressure (BHP) and can provide valuable insight regarding the formation's pore pressure. Differentiation between drill gas and connection gas can be easily achieved by accounting for the annular volume and the volumetric flow rate of drilling fluid into the well.

Most connection gas is a result of one or a combination of these three different mechanisms:

1. The aforementioned liberation of gas present in the drilled rock
2. Formation-fluid flow into the wellbore as a result of an underbalance state (Alberty and Fink, 2014)
3. Gas diffusion into OBM or SBM (Bradley et al., 2002).

Since the gas present in the drilled rock volume should not change significantly within a formation section, any increase in connection gas readings over pre and post connection drill gas readings is an indication that either mechanism 2 or 3 is taking place. In the case of mechanism 2, an underbalance situation, the gas cut would be concentrated and register a significant spike at surface as the formation fluid influx entered the wellbore all at once. However, in a situation with an over pressured low permeability formation, the influx volume may be small and therefore difficult to differentiate from drill gas. One additional downhole phenomena which could appear as connection gas at surface is the hydrocarbon swap-out mechanism that has been observed in some wellbore breathing incidents (Ashley, 2000). The swap out mechanism will be explained in detail later in this section, but is mentioned here because of its potential contribution to connection gas. Hydrocarbon swap-out will typically exhibit long drawn out gas peaks as the hydrocarbons flow into the wellbore in combination with drilling fluid over the entire course of the connection.

It is important to understand each of these mechanisms in order to properly identify them at surface and make proper decisions to combat them. For instance, the best course of action for an underbalance condition during connections would be to raise the mud weight, while this same action for a well experiencing hydrocarbon swap out could exacerbate the problem.

2.2.6.3 Trip Gas

Trip gas is essentially the same phenomenon as connection gas, but the mud column is in a static state for significantly longer. Trip gas is the gas registered at surface when the mud that was in the open section while tripping in and out of the hole is circulated to surface. Depending on the purpose of the trip and the depth of the well, tripping in and out of the hole, along with any actions taken with equipment at surface, could take anywhere from a few hours to multiple days. Because of the significantly longer time frame, gas diffusion into an OBM or SBM has the potential to significantly increase the gas cut of the mud when it returns to surface. The process of gas diffusion into the mud is driven by the low partial pressure of the gas within the drilling fluid in comparison with the partial pressure of the formation gas and insignificantly influenced by higher wellbore pressures (Bradley et al., 2002).

Additionally, because of the drill string being pulled out of the hole during tripping operations, there will certainly be temporary reductions in the BHP during the process which could lead to formation fluid influxes. If this were to take place, there would likely be significant gas peaks registered when the fluids are circulated back to surface as this volume would have entered the wellbore all together. However, this could be combatted by circulating the well full of a higher mud weight drilling fluid prior to tripping out of the hole in order to ensure a more significant level of overbalance at static conditions. This increase in mud weight is known as a trip margin.

2.2.6.4 Formation Fluid Influx

A formation fluid influx, known as a "kick", is the process of formation fluids flowing into the wellbore due to the pressure in the wellbore being lower than the pressure in the formation. The influx may be composed of brine, oil, gas, or a combination of any of the three. It is referred to as a well control incident and should always be taken extremely seriously as it poses a threat to the safety of all crew members on board if handled improperly. An improperly handled kick can result in losing control of the well and a blowout.

Typically, the key identifier for a kick is a mud gain in the pits as this indicates fluid has likely been added to the system via an influx. It is the responsibility of the driller and mud loggers to identify such pit gains, determine if a kick has been taken, and, if so, shut the well in using the blow out preventer (BOP). Once the well has been shut-in, the influx must be circulated up the annulus and out of the well using the choke manifold at surface. Precaution should be taken with any form of a pit gain because the formation fluids are often of a lower density than the drilling fluid. Therefore, any volume of formation fluids that enter the well will reduce the hydrostatic head of the column, increasing the degree of underbalance and potentially exacerbating the well control event. There are several other methods of kick detection which will be discussed later, but pit gains are the primary method. Since wellbore breathing also results in pit gains, differentiation between the two can be difficult.

2.2.6.5 Hydrocarbon Swap Out

Hydrocarbon swap out is a phenomenon that can occur during wellbore breathing events in a fractured hydrocarbon bearing zone. During circulation, the increased annular pressure forces opens the fracture or fractures forcing fluid out into the formation and results in mixing of drilling fluid and hydrocarbons. Once circulation is stopped, the drop in wellbore pressure allows the fractures to close and force fluid back into the wellbore. In the case of a hydrocarbon swap out, some drilling fluid is left out in the formation or fracture system and some hydrocarbons are brought back into the wellbore. The effective result is a kick being taken without any net gain of fluid in the system. This renders it extremely difficult to identify at surface and therefore very dangerous as the driller may unknowingly circulate the kick up the annulus. The difficulty in identifying influxes from hydrocarbon swap out makes this phenomenon dangerous because the influx may be unknowingly circulated up the annulus and to surface. This can result in large gas volumes exiting the mud system at surface, potentially overloading gas separation equipment and posing a safety risk due to the potential for ignition of the gas.

2.2.6.6 Flowback and Flowback Finger Printing

When the mud pumps are shut down and circulation is stopped, a volume of drilling fluid, in the range of 20 to 50 barrel flows back to the mud pits and is known as flowback (Ali et al., 2013). Part of this flow can be attributed to gravity as the mud circulating system is typically located below the rig floor, so fluid in this system will drain to the pits. In addition to this, the loss of ECD at pump shut off results in drilling fluid expansion and some elastic wellbore rebounding contributing to this flow out of the well (Ali et al., 2013). The volume between the rig floor and the pits is easily quantified and remains constant throughout the drilling process, but the flowback out of the well is dependent on the volume of the annular space, amount of open hole-section, and the pressure change between circulating and static conditions; each of which change over the course of a drilling operation. Because of this variability, it can be difficult to determine if the well is simply experiencing flow back or if a kick is being taken.

Flowback fingerprinting was developed as means to monitor flowback and differentiate between normal flowback and a kick. Flow back fingerprinting is the process of plotting the pit volume change vs. time after pumps are shut down and comparing with past flowbacks. A typical flowback fingerprinting plot is displayed below in figure 2.18. The flowbacks are typically plotted consecutively on the same plot in order to obtain a cluster of flowback profiles. This can be monitored at each connection, but typically the mud logger will set an alarm on the system to signal if a certain rate or total volume gained has been exceeded.

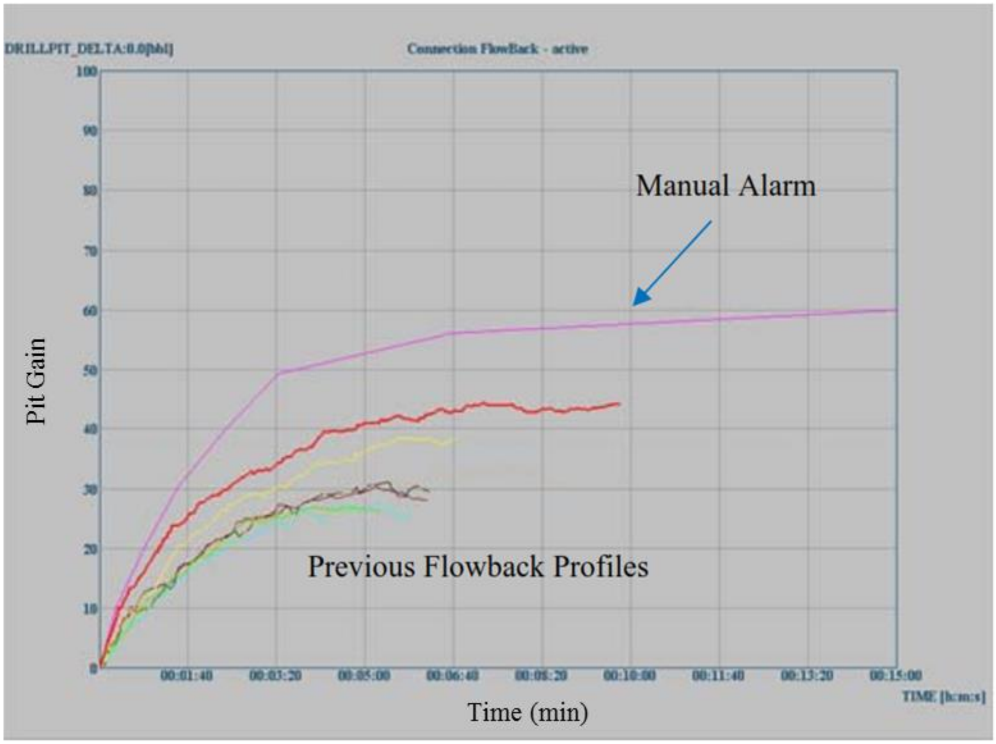

Figure 2.18 Flowback profile monitoring from GOM well (Ali et al., 2013)

2.2.6.7 Shut-in Drill Pipe Pressure (SIDPP) and Shut-in Casing Pressure (SICP)

Once a kick has been detected and the well has been shut-in, pressure builds at surface until the combination of surface and hydrostatic pressures equal the formation pressure and the inflow has stopped (Mitchell and Miska, 2011). Once the surface pressures have stabilized, the shut-in drill pipe pressure (SIDPP) and shut-in casing pressure (SICP) can be used to determine the pressure of the formation, and subsequently the mud weight required to kill the well. Figure 2.19 below provides a simplistic representation of what the shut-in well looks like after taking a kick. This graphic is also helpful for visualization when using the formulas listed on the following page.

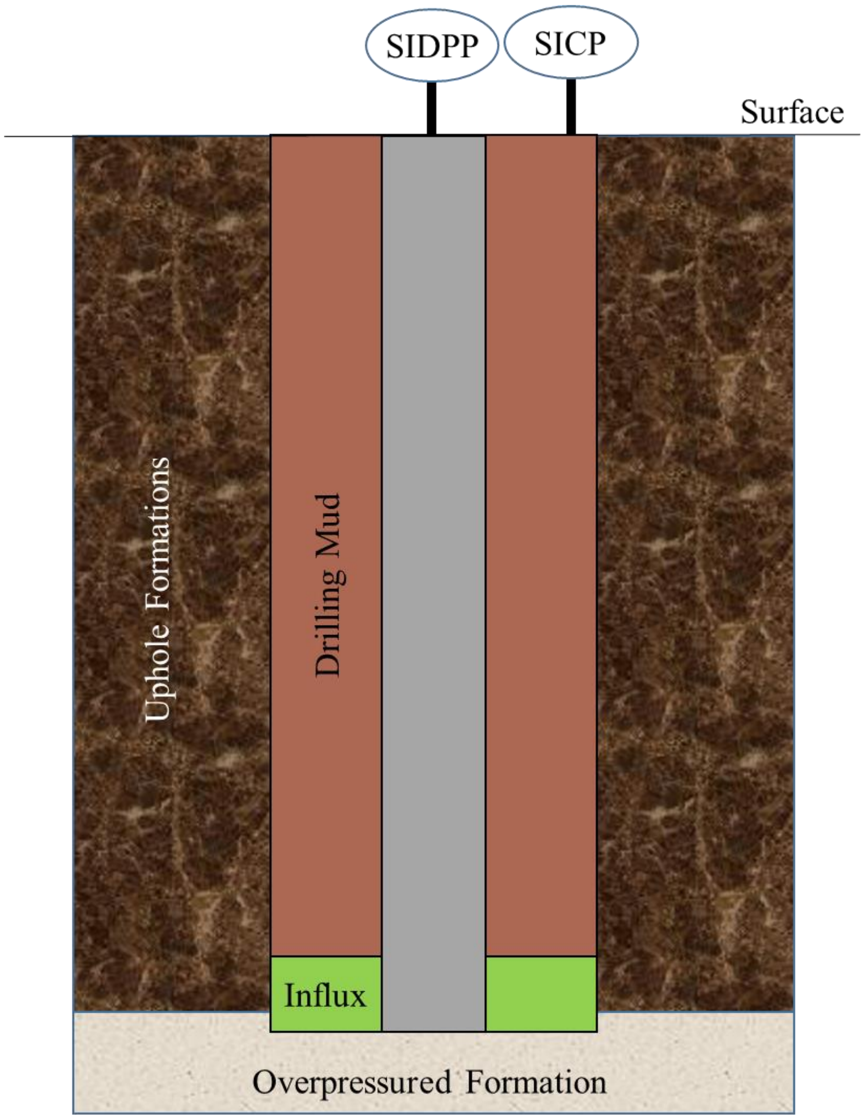

Figure 2.19 Graphic depicting well control situation with a shut-in well.

As can be seen in Figure 2.19, a kick has been taken and now occupies a portion of the annular space below the column of drilling mud. The drill pipe typically has a backflow valve near the bit so it remains completely filled with drilling mud. Therefore, the hydrostatic head of the fluid in the drill pipe and the SIDPP should provide an accurate estimate of the formation pressure:

$$P_{formation} = \ SIDPP + \ P_{DP\ Hydr.} \tag{2.1}$$

It is also useful to determine the type of influx that has occurred which can be calculated using the surface pressures, mud density, and the kick height in the annulus:

$$\rho_{kick} = \ \rho_{mud} - \frac{SICP - SIDPP}{h_{kick}} \tag{2.2}$$

Where the densities are in psi/ft, the pressures are in psi, and the kick height is in feet. The kick height is challenging to estimate accurately but can be calculated by:

$$h_{kick} = \ \frac{V_{kick}}{A_{annulus}} \tag{2.3}$$

Where,

V_{kick} = kick volume (ft^3)

$A_{annulus}$ = cross-sectional area of annulus (ft^2)

2.2.6.8 Flow Check

Flow checks are operational procedures designed to identify kicks by stopping circulation, leaving the BOP open, and checking for flow out of the well. Flow checks are typically performed during the course of drilling when an abnormality has occurred to ensure the well is static. A drilling break, sudden increase in rate of penetration (ROP) while drilling, is a common reason for performing a flow check as the increase in ROP indicates a formation change or increase in pore pressure. Flow checks are also very useful for differentiating between an overpressured formation and wellbore breathing, which are often confused. In this case, wellbore breathing could be identified as the cause if the flow out of the well dissipated over time and eventually stopped. Whereas, for an overpressured formation, the flow would not dissipate and may actually increase due to the displacement of the heavier drilling fluid. This differentiation becomes increasingly difficult in situations where there is a small differential between the formation and wellbore pressures or the formation has very low permeability. The rate of fluid flow into the well is directly related to these variables and it may take a very long flow check, 45 – 60 minutes, to determine the subsurface process occurring.

2.2.6.9 Swab Pressures

Swab pressures are a temporary reduction in the bottom hole pressure due to the swabbing effects of pulling drill pipe or a tool out of the hole. The primary danger in these situations, is that the swab pressure temporarily places the wellbore into an underbalance condition where an influx may occur. Two common situations where swab pressures may be induced are during tripping operations and wireline operations where the tool is pulled to surface too quickly. There are, however, multiple software packages provided by service companies designed to calculate swab pressures and determine a maximum allowable rate for pulling out of the hole with a given tool and hole size. As with any procedure, it is only effective if followed, so effective communication to the company man and well site crews is crucial.

An additional swab pressure can occur when the bit, reamer, or stabilisers have balled up or even packed off resulting in a significantly larger diameter for the effected downhole equipment. Tripping out of the hole in these cases would result in extreme swab pressures and would significantly reduce the bottom hole pressure, potentially facilitating large fluid influxes. Large volume swabbing can be identified while tripping by the fluid level in the annulus not dropping the proper amount or even rising in extreme cases. Potential solutions would be to trip out of the hole wet or turn the pumps on while pulling each stand in extreme cases.

2.2.6.10 Trapped Pressure

Trapped pressure is any artificial increase to the SICP and SIDPP above the surface pressure required to balance the pore pressure of downhole formations. In instances when a kick is believed to have occurred while circulating, shutting in the well prior to the pumps shutting off can result in trapped pressure. If trapped pressure is not properly identified, it can result in the calculation of inaccurate and unnecessarily high kill mud weight. While a higher kill mud weight will effectively kill the well, the unneeded increase in mud weight would subject the wellbore to increased pressures while drilling ahead and may lead to lower rates of penetration and lost circulation issues.

2.2.6.11 Pressure Bleed Off

Pressure bleed off is the process of opening the choke up for short periods after the well has been shut in to remove any excess fluid or pressure in the system above what is required to balance the pore pressure of the downhole formation. This is an important step for the reasons mentioned above in section 2.2.6.10, but it is also important to minimize the pressure bled off in excess of the trapped pressures. Mitchell and Miska (2011) provided some suggestions for bleed off procedures including:

- Focus on the SIDPP as it indicates the bottom hole pressure and bleed small volumes (~ ½ bbl) of fluid at a time, close choke and monitor SIDPP

- Continue prior step until the SIDPP stops decreasing, if SIDPP reduces to zero continue bleeding small volumes off until the SICP stops decreasing.

It is important to stop bleed off when the SIDPP no longer decreases because pressure bled off in excess of the trapped pressure will allow more formation fluid to enter the wellbore as this pressure is needed to balance the formation pore pressure. The resulting larger influx volumes can make a kick more difficult to handle at surface depending on the capacity of the mud-gas separator. Also, larger influx volumes will result in higher wellbore pressures due to gas expansion when circulating the kick out of the wellbore. It is important to keep these pressures to a minimum because fracturing the formation while circulating a kick out of the well can lead to an underground blow out.

2.2.6.12 Blow Out

A blowout is an uncontrolled flow and release of reservoir fluids at the surface driven by the reservoir pressure. A blowout is the worst-case scenario for a drilling operation and indicates that there has been a failure in one or some combination of the well control barriers, equipment, and procedures. As evidenced by the Macondo blowout, which occurred in the Gulf of Mexico in 2010, a deepwater blowout can result in the loss of human life, environmental damage, a significantly diminished company reputation, and massive financial costs for damages, fines, and liabilities (Carter, van Oort, and Barendrecht, 2014).

In addition to the more common surface blowout, there is another type of blowout called an underground blowout. An underground blowout consists of uncontrolled flow of reservoir fluids out of the reservoir and into some lower pressured up-hole formation which was fractured due to the excessive pressure in the wellbore. The primary situation in which this can occur involves the circulation of a gas kick up the annulus. As the gas moves up the annulus, it begins to expand, reducing the hydrostatic head of the mud column and requiring higher surface pressures to maintain the required BHP. If the gas volume has not made it inside the casing, the formation above and to the base of the gas volume will be subjected to increased pressures. Because of this, the maximum pressure that the wellbore can handle without inducing a fracture, the maximum allowable annular surface pressure (MAASP), is calculated in well control situations; Operational decisions are then made to keep annular pressures below the MAASP and avoid potential underground blowouts (Santos et al., 2011).

2.2.6.13 Kick Tolerance

Kick tolerance is a key concept in well design and drilling operations which is related to a wellbore's ability to withstand pressures during a well control situation without fracturing. Typically expressed in barrels, the kick tolerance is the largest gas influx volume at the highest expected pore pressure that can be taken without exceeding the MAASP while circulating the kick out of the hole. Therefore, kick tolerance is a function of the cross-sectional area of the annular space, mud weight, and true vertical depth (TVD). Santos, Catak, and Valluri (2011) explained that the kick tolerance dictates the number and setting depth of casing strings in a well plan, is used to determine whether drilling ahead is a safe proposition, and indicates whether a given kick can be circulated up the annulus or requires bull heading back into the formation.

In situations where a kick has already been taken, the pore pressure of the formation will be known and can be incorporated into the calculation for kick tolerance before deciding whether to circulate the kick up the annulus. Additionally, in this case it would also be beneficial to use the SICP for determination of the type and density of the influx which has occurred. These two steps will yield a more accurate value for kick tolerance and prove beneficial when determining the best way forward.

2.2.6.14 Slow Circulating Rate Pressures

Slow circulating rate pressures are the increase in BHP caused by frictional losses when pumping through the choke or kill line while the well is shut-in. They are typically recorded on deepwater wells because the choke and kill lines may be several thousand feet long and impart significant frictional pressures. The slow circulating rates are usually recorded during BOP tests and measured at different circulating rates that may be used during a well control incident. These circulating rates are recorded in strokes per minute (SPM) and at a range of rates (30, 45, and 60 SPM for example). Slow circulating pressures are important during well control operations as they will increase the bottom hole pressures while circulating out a kick and must be incorporated in kick tolerance calculations to avoid fracturing the wellbore.

2.2.7 Conventional Drilling

Conventional drilling is the standard and most common method for drilling an oil or gas well. It uses drill pipe to transmit torque from the top drive to the bit while circulating fluid down the drill pipe and up the annulus. The mud column is open to the atmosphere at surface and outflow from the annulus is directed to the cuttings handling system for removal of solids prior to going back into the active mud system. Once a stand of pipe has been drilled down, the pumps are shut off to make a connection. Therefore, ECD is lost at connections and there is a reduction in bottom hole pressure compared to circulating conditions. The approach for conventional drilling operations is to maintain a high enough mud weight to maintain overbalance at all times, which results in an ECD significantly above the pore pressure. In wells with narrow drilling windows, it may be impossible to maintain a bottomhole pressure above the pore pressure during static conditions and below the fracture gradient during circulating conditions. For these narrow drilling window wells, conventional drilling systems may not be capable of reaching the target depth.

2.2.8 Unconventional Drilling Methods

Unconventional drilling methods incorporate specialized equipment and have been developed as a means to combat lost circulation and wellbore breathing, in addition to enabling drilling of wells with extremely narrow drillings windows, that would be impossible with conventional techniques.

2.2.8.1 Managed Pressure Drilling

Managed pressure drilling (MPD) is a form of drilling which employs a closed fluid system, which can be pressurized in order to manage the bottomhole pressure during drilling operations. It allows more precise and instantaneous control of the downhole pressures than would be possible using mud weight and flow rate adjustments alone. To create the isolated fluid system, a device called a rotating control device (RCD) is installed to create a seal in the annulus and divert flow to a MPD choke manifold where backpressure can be applied as needed while circulating (Driedger et al., 2013). During connections and any other times the pumps are shut down, there is an auxiliary mud pump which applies back pressure to the annulus in order to maintain the desired bottomhole pressure. Figure 2.20 below displays a typical MPD and mud circulating system layout.

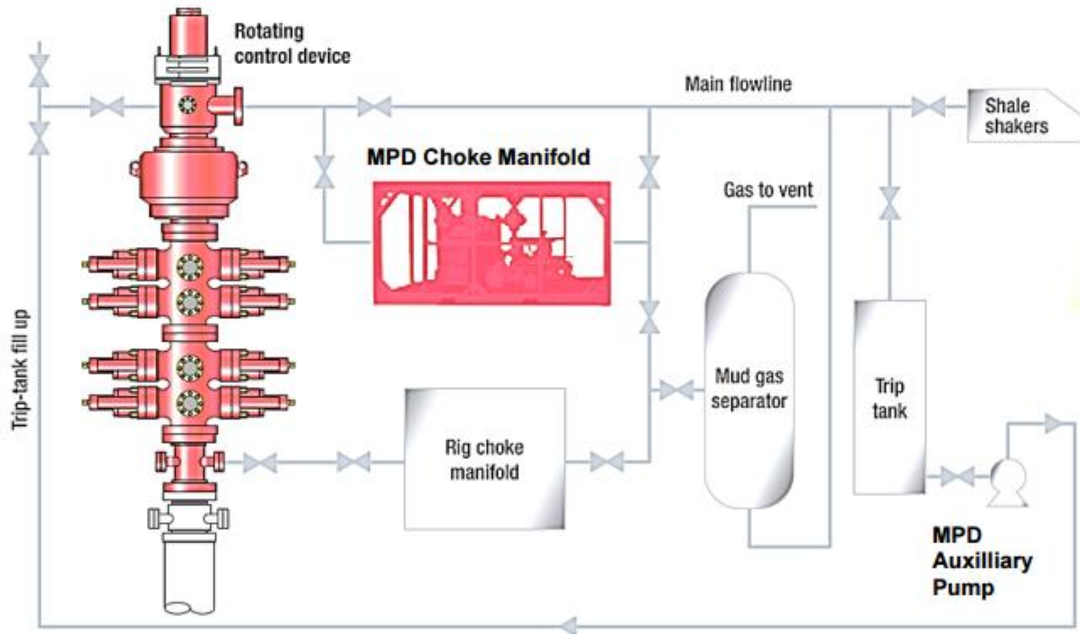

Figure 2.20: Diagram of a typical MPD system layout (Driedger et al., 2013)

2.2.8.2 Pressurized Mud Cap Drilling

Pressurized mud cap drilling (PMCD) is a specific application of MPD developed for wells that have lost circulation issues concurrently with well control issues. It was developed to eliminate non-productive time that typically results from drilling fluid losses in highly fractured carbonates in Southeast Asia by using the fractured formation to dispose of the fluid and cuttings downhole (Runtuwene et al., 2009). PMCD involves pumping a sacrificial fluid, usually sea water, down the drill pipe with no returns and pumping heavier drilling mud down the annulus and applying back pressure to maintain a pressurized mud cap above the loss zone. Runtuwene et al. (2009) also suggest that the annular drilling mud used should be of a density less than required to balance the formation pressure and should be pumped down the annulus at a rate high enough to maintain a velocity greater than the gas migration rate in the mud. This lighter drilling fluid requires back pressure applied by the RCD which can be monitored for any pressure changes indicative of downhole changes such as kicks.

2.2.8.3 Dual Gradient Drilling

Dual gradient drilling (DGD) is an unconventional drilling method developed to combat narrow drilling windows in deepwater basins such as the Gulf of Mexico. Using conventional drilling requires an excessive number of casing strings in these wells. DGD incorporates two fluid columns of different densities in the annulus to achieve the hydrostatic pressure needed rather than a single column of one density used in conventional drilling operations. DGD was originally proposed for deepwater applications in 1996 through an industry workshop that ultimately resulted in the formation of the SubSea MudLift Drilling JIP focused on providing a total solution for DGD inclusive of both the hardware and operational methodology to implement it effectively (Smith et al., 2001). The system developed by this JIP was a technical success and ultimately resulted in Chevron contracting AGR Subsea, Pacific Drilling, and GE Oil and Gas to develop a built for purpose DGD system and drilling rig for use in the deepwater Gulf of Mexico (Dowell, 2010).

The DGD system incorporates seawater within the riser from a point near the mud line up to the drilling rig and heavier drilling fluid below the mud line. A subsea rotating control device (SRD) is placed a small distance (~60 ft.) above the BOP to create a seal in the annulus preventing mixing of the fluids and any gas migration up the riser (Dowell, 2010). A mudlift pump (MLP) to move the drilling fluid and cuttings to surface in conjunction with a solids processing unit (SPU) to reduce the solids particle size is installed on top of the lower marine riser package and powered by seawater pumped from surface (Dowell, 2010). When pumps are stopped for connections, the heavier mud present in the drill pipe will exert a higher pressure at the bit than the dual gradient system in the annulus, which would lead to U-tubing in a conventional drill string design. To combat this U-tubing effect, a special drill string valve which closes when the pumps are shut off and opens during circulation was designed and added to the BHA (Dowell, 2010). Figure 2.18 displays a diagram of a DGD subsea system and plots highlighting the differences in downhole pressure gradients between a conventional and DGD system.

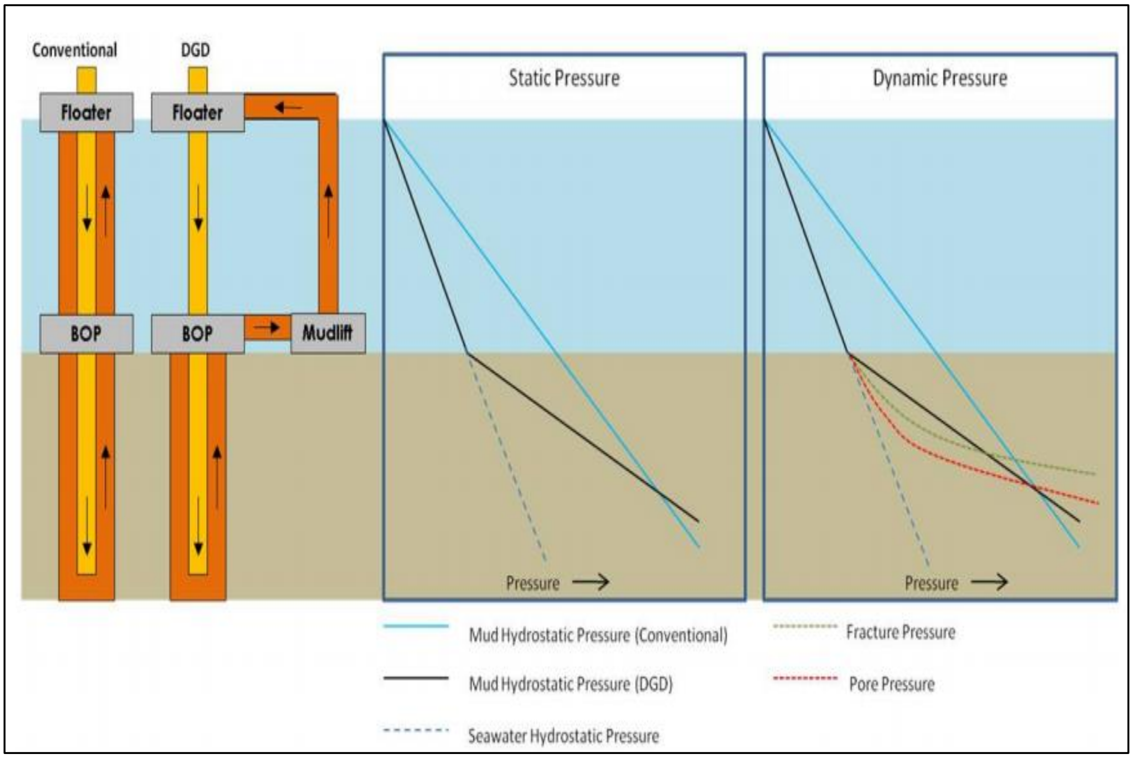

Figure 2.21: DGD system and the differences in mud hydrostatic gradient compared to a conventional drilling system (Stave, 2014).

2.2.8.4 Continuous Flow System Drilling

Continuous flow system (CFS) drilling is similar to MPD in that it aims to maintain a constant BHP throughout drilling operations, but it accomplishes this by maintaining constant circulation rather than pressurizing the mud system. The CFS consists of specially engineered subs with a side access port made up to the top of each stand, a clamp with secondary flow line to attach to these subs during connections, and an automated control system to switch drilling fluid flow between the top drive and side access port on the sub (Cunningham et al., 2014). When a stand is drilled down, floor hands manually attach the clamp to the sub and the automated system switches the flow to the side port. The top drive can then be disconnected, pull another stand of pipe out of the derrick, and make this stand up to the drill string. At this point, the automated system would switch flow back to the top drive and drilling could begin.

Additional advantages of CFS are uninterrupted data from downhole tools since they require circulation to transmit mud pulses to surface and improved hole cleaning due to the lack of static conditions when cuttings would settle (Cunningham et al. 2014). One negative with a CFS is that mud pump failure would result in an immediate reduction in annular pressure, which could put the well in an underbalance condition and cause an influx. However, a MPD system employed in combination with CFS could maintain wellbore pressures in the event of a pump breakdown.

2.2.8.5 Casing or Liner Drilling

Casing drilling is an unconventional drilling technique in which casing is used, with a specialized bit, to drill a hole section and is subsequently cemented in place once its setting depth has been reached. In some circumstances casing drilling can provide a significant cost benefit for a drilling program by eliminating the trip out with drill pipe and back in to the hole with casing that are required in conventional drilling operations. Additionally, and of more importance to this thesis, casing drilling has proven an effective approach to combat lost circulation issues as well as wellbore breathing (Rosenberg and Gala, 2011). The exact underlying mechanism causing this isn't well understood, but is thought to be related to the small annular space between the formation and casing that the mud and cuttings must be circulated through. This belief has led to the process being commonly referred to as the "casing smear effect".

Chapter 3 Wellbore Breathing Case Studies

3.1 Case Studies from Literature

Several case studies have been published in literature which will be examined in detail in this section. Each of these wells encountered wellbore breathing although the amount of details and data published varies significantly between them.

3.1.1 Timor Sea, Offshore Australia

Ashley (2000) published a case study detailing two wells drilled in the Bonaparte Basin of the Timor Sea off the northwest coast of Australia and operated by Woodside Energy. The first well, the Bard-1, was spudded in October 1998 and was ultimately plugged and abandoned short of target depth (TD) due to severe wellbore breathing coupled with hydrocarbon swap-out. The Jura-1 was subsequently spudded in July 1999 targeting the same structure, but about 28 miles away. The Jura-1 also encountered wellbore breathing events but without any associated hydrocarbon swap-out and was able to successfully reach TD. Figure 3.1 below displays a map of the Jurassic Plover-Plover petroleum system within the Bonaparte Basin showing discoveries in the area, water depths, and well locations including the Bard-1 and Juna-1 towards the top left of the figure.

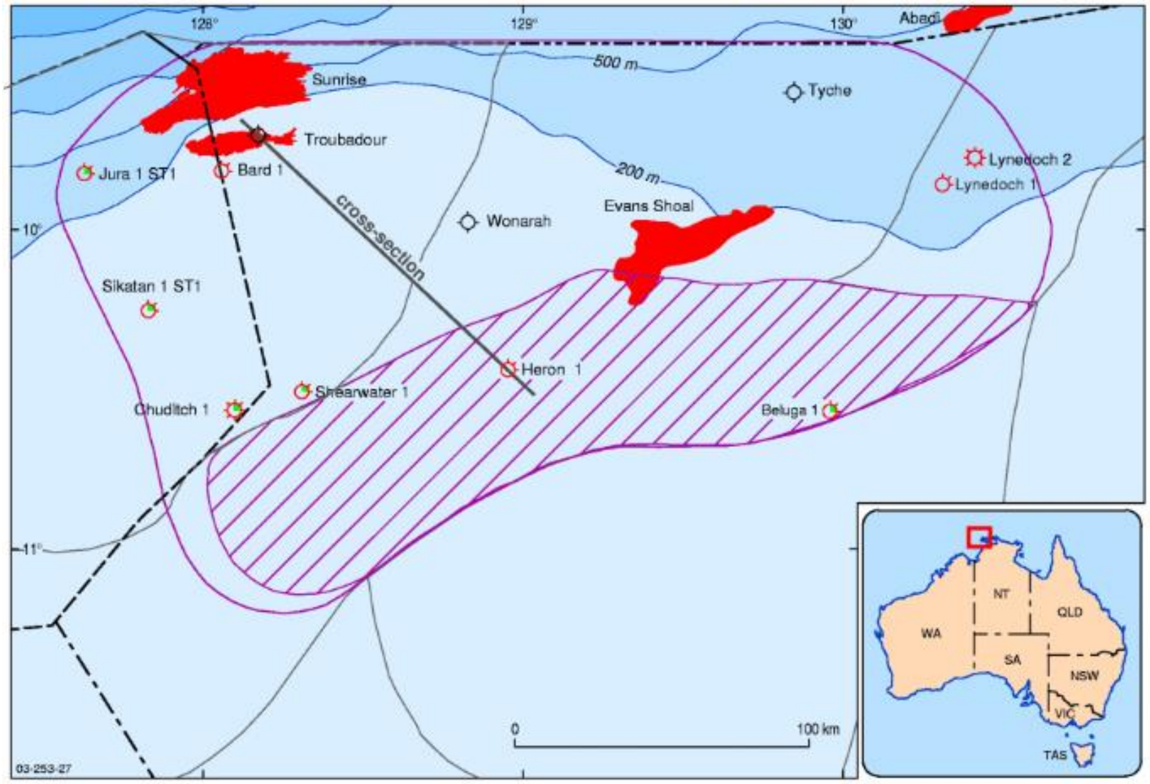

Figure 3.1: Map of the Jurassic Plover-Plover petroleum system within the Bonaparte Basin (Earl, 2004)

3.1.1.1 Bard-1

Ashley (2000) describes the exploration well plan, which can be seen in Figure 3.2, as targeting the Plover formation with a simple two string design and an 8 ½" hole to TD using a water based mud system. Furthermore, a FIT to 11.75 ppg was planned at the 9 5/8" shoe and a 10.92 ppg mud weight was chosen to drill the overpressured Jamieson Formation with a plan to gradually reduce this mud weight to a minimum of 9.8 ppg prior to entering the Darwin formation.

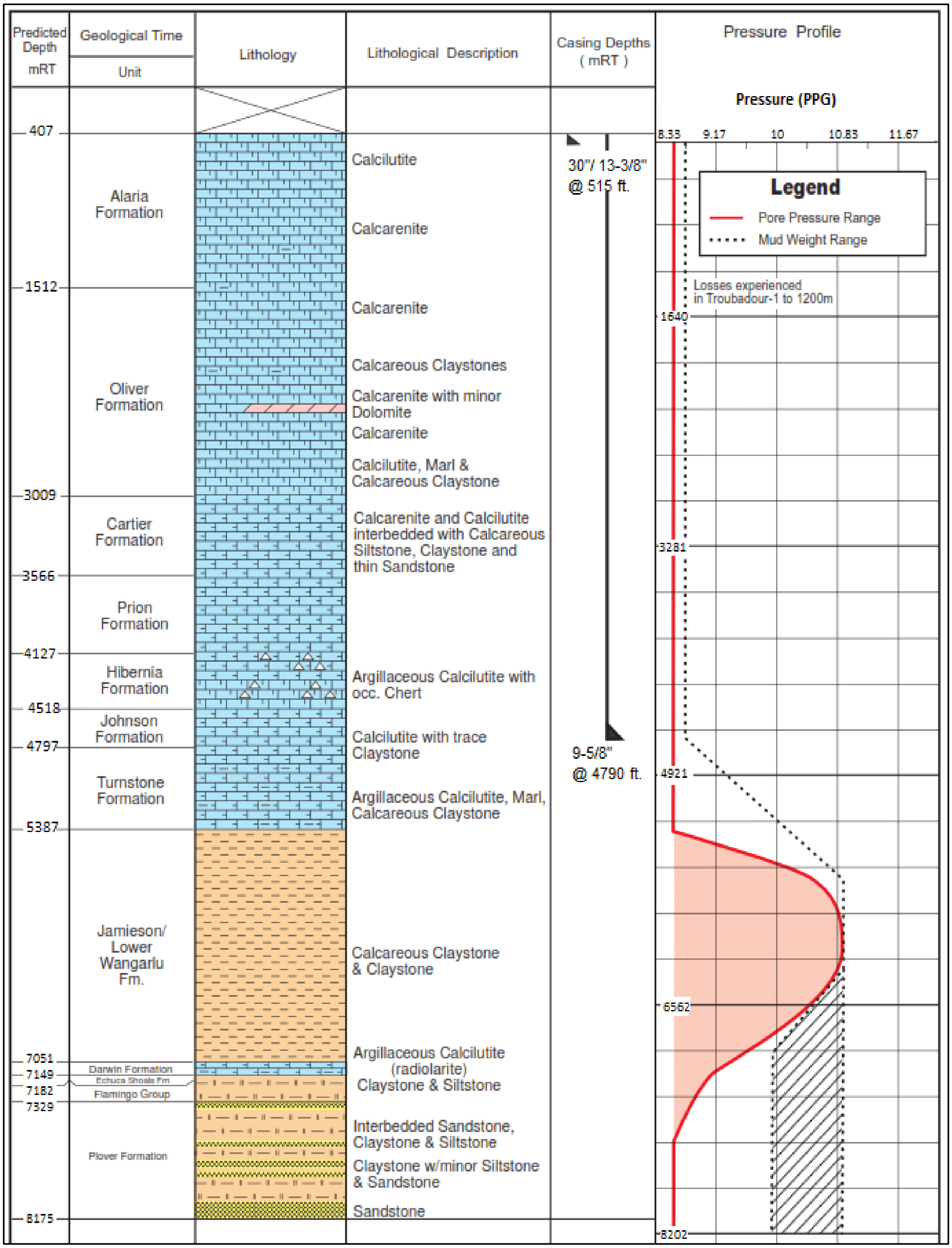

Figure 3.2: Predicted section and pore pressure for Bard-1 (Modified after Ashley, 2000)

As planned, the mud weight was reduced prior to penetrating the Darwin and Echuca Shoals formations, but flow increased at surface followed by significant gas readings while drilling at 7,100 ft with a mud weight of 10.42 ppg. The well was shut-in and although the SICP and SIDPP were zero, it was circulated through the choke as a precaution. After this circulation, the SIDPP and SICP were 170 and 180 psi respectively, the decision was made to increase the mud weight to 10.92 ppg to counteract the believed overpressure. This was the first step in a well control incident that transpired over a 5 day period and ultimately resulted in the well's plugging and abandonment. Figure 3.3 displays the measured pressures as well as the increases in mud weight (ΔBHP) over the first 3 ½ days of the well control incident and the following paragraph provides details.

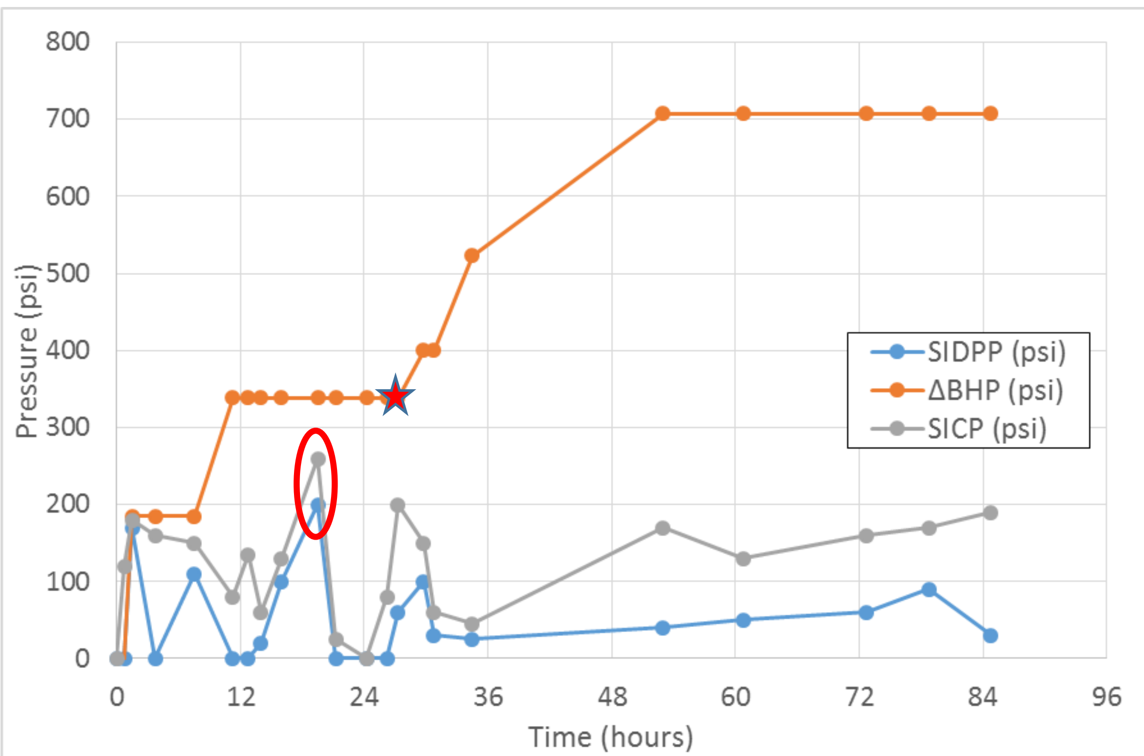

Figure 3.3 Pressures during Bard-1 well control incident (Data from Ashley, 2000)

In Figure 3.3, the orange points indicate the increases in BHP caused by raising the mud weight in comparison to the initial mud weight of 10.42 ppg. The mud weight was raised first to 10.92 ppg at 1.5 hours, then to 11.33 ppg at 11.25 hours, and kept at this density until the 27 hour point which is marked with a star. Numerous circulations, bleed offs, and flow checks to static conditions were recorded over the course of this initial 27 hour period. During the course of these operations, there were hydrocarbon returns to surface throughout and bleed off volumes were significantly larger than expected for trapped pressure, but there were no pit gains and the SIDPP was reduced to zero several times (Ashley, 2000).

At this point, the downhole mechanism was diagnosed as a high pressured low permeability zone and the decision was made to increase the mud weight further to 11.83 ppg and then 12.33. This only exacerbated the problem resulting in higher pressures, higher gas cuts, and fluid losses. Ultimately, the crew was unable stop these losses and hydrocarbon returns persisted so the decision was made to set cement plugs and abandon the well.

In the post well review, Ashley (2000) suggests that the mechanism responsible for the anomalous pressure data and hydrocarbon returns was wellbore breathing coupled with hydrocarbon swap-out and cited eight reasons:

- The formations below the Jamieson shale were thought to have a fractured lithology, which if filled with hydrocarbons would lend itself to this mechanism.
- The SIDPP was reduced to zero several times during the well control event and the well was static when opened, indicating overbalance on bottom-hole pressure.

- SIDPP did not decrease when the mud weight was increased to 12.33 ppg; if the well would have been underbalanced this increased BHP should have reduced the SIDPP somewhat.
- There was a significant influx off hydrocarbons, 70 bbls of oil, without any associated pit gains.
- The volume of fluid bled in instances of "trapped pressure" were 10 bbl per 100 psi compared with calculated compressibility from the FIT of a ½ bbl per 100 psi, indicating closure of fractures was contributing mud back to the system.
- Influxes of hydrocarbons steadily increased with mud weight, indicating the higher annular pressures were causing additional fracture opening and subsequent hydrocarbon swap-out.

Figure 3.4 below displays hydrocarbon levels at surface during the well control incident. The oil percent is cumulative throughout the incident as it was not removed, but the gas readings are instantaneous as the gas is separated out of solution at surface.

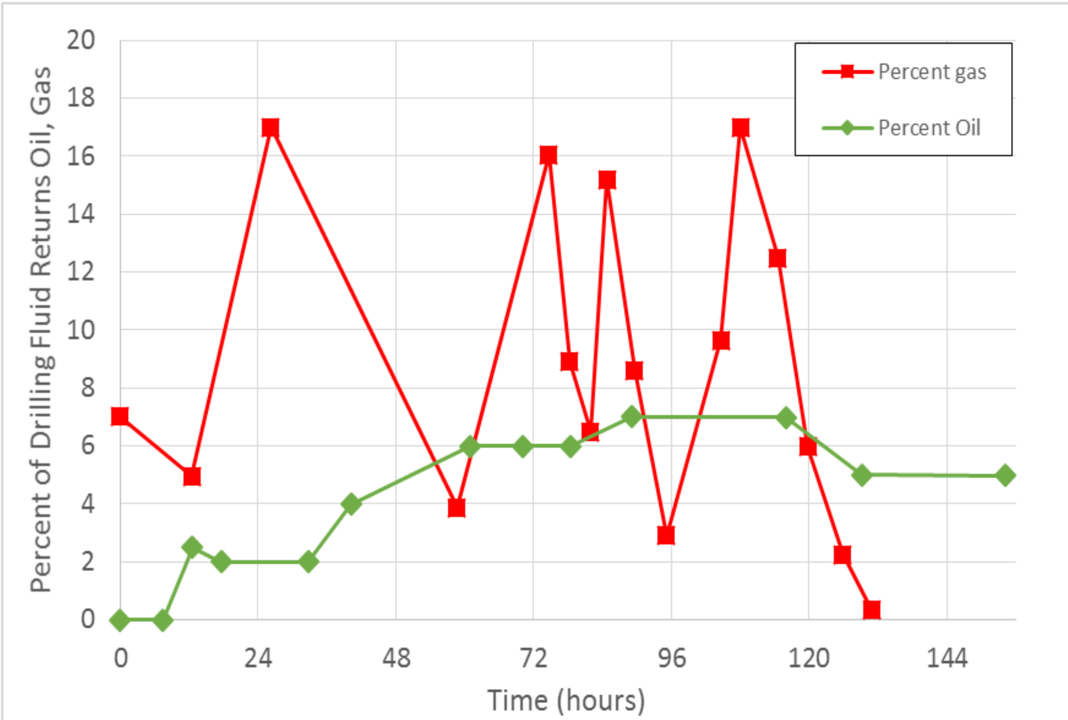

Figure 3.4: Percent of returns, oil and gas (Data from Ashley, 2000)

In addition to the reasons listed by Ashley, which were primarily during the latter portion of the well control event, there is additional evidence within the first 27 hours of the well control incident that support wellbore breathing coupled with hydrocarbon swap-out as the influx mechanism. It is important to note that the first 27 hours composed the critical time period for this well. The data gathered during this period was all that was available when the mechanism was mischaracterized as a low permeability high pressure zone.

First, the mud weight was increased first by 0.5 ppg and then by an additional 0.4 ppg for a total increase of 0.9 ppg, but there was no associated reduction in the SIDPP. On the contrary, the SIDPP was actually higher after each mud weight increase. If the well was in a state of underbalance, this 350 psi increase in wellbore pressure should have resulted in some reduction in SIDPP.

Second, in Figure 3.3, the SICP and SIDPP at the 19 hour mark are circled in red as these were the highest shut in pressures observed throughout the incident. These pressures were recorded after a circulation of 1.25 times the wellbore volume with 10.92 ppg while holding an additional 100 psi of back pressure on the well at the choke. The additional 100 psi of back pressure is equivalent to a 0.3 ppg increase in mud weight without taking into account any additional back pressure added by frictional effects of flow through the choke line. If the downhole mechanism was a high pressure low permeability zone, the shut-in pressures should have been lower after this circulation compared to previous shut-in pressures. Furthermore, these high shut-in pressures suggest that the increased annular pressures during circulation actually made the problem worse. This is consistent with our understanding of wellbore breathing, in which higher annular pressures result in increased fracture opening and higher surface pressures if the fluids are not allowed to flow back into the well prior to shut-in.

Last, there were two sequences in the first 27 hours in which the well was circulated conventionally rather than through the choke manifold with the well shut-in. During each of these two circulations, flow significantly increased from the well when 65 to 70 percent of the annulus volume had been displaced, followed by significant gas readings at surface. This behavior is consistent with a volume of oil entering the wellbore when the pumps were off, this volume being circulated up the annulus, and the gas rapidly breaking out of solution when volume reaches a depth where the annular pressure drops below the bubble point. This once again suggests that wellbore breathing coupled with hydrocarbon swap-out was the mechanism because this would have resulted in an oil influx when circulation was stopped, with no associated pit gain. It would be difficult for a high pressure low permeability zone to cause similar behavior as the volume of influx would be limited by the formation's permeability in the short time that the well was static prior to each circulation and a pit gain would be associated with the influx. Assuming the influx occurred at or near bottom-hole, the annular pressure was between 1,200 psi and 1,400 psi at the depth where the gas is believed to have broken out. These pressures are within the range of bubble points expected for hydrocarbon oils, confirming the plausibility of the increased flow being due to gas breaking out of solution.

3.1.1.2 Jura-1

The Jura-1 was spudded roughly 8 months after the Bard-1 with the objective of evaluating the Plover Formation on the same structure that the Bard-1 had been drilled. Ashley (2000) explains that due to the experiences on Bard-1, several new operational procedure were implemented prior to spudding the Jura-1 including:

- Reduced circulating rates in order to reduce the ECD.
- Staging pump start up and shut down over five minute periods in order to allow any fluid swap-out encountered to occur gradually.
- Implementation of a PWD tool in the BHA to monitor downhole pressures.
- Flow through both the choke and kill lines when circulating with the well shut-in to reduce frictional pressures.
- Use flowback fingerprinting to distinguish between wellbore breathing and a kick.

- If hydrocarbon swap-out was encountered, circulate bottoms up after each connection prior to drilling ahead.

Similar to the Bard-1, wellbore breathing was encountered in the interval of the Darwin and Echuca Shoals Formations. However, no hydrocarbon swap-out was encountered in conjunction with the wellbore breathing. In accordance with the new operational procedures, the well was shut-in and circulated bottoms up after the first two connections when wellbore breathing occurred. In each instance, the well was static after pressure bleed off and no hydrocarbons were returned to surface so the decision was made to drill ahead while monitoring flowback fingerprints at connections. Following this procedure, no influxes occurred and the well was successfully drilled to TD.

It is worth noting that the Jura-1 was drilled with the same semi-submersible drilling rig and the same crew as the Bard-1 with the only major equipment or tool change being the incorporation of a PWD tool in the drill string. This demonstrates that a well-trained and well-educated operations team is a necessity in situations where wellbore breathing is encountered and can be the difference between abandonment of a well and reaching TD. In addition, while the PWD tool did prove beneficial in monitoring downhole pressures due to ECD, there were no other significant changes regarding the equipment and tools used to drill the well. Identification of the back flow at connections, verification that this back flow was due to wellbore breathing, and verification that no hydrocarbons were entering the wellbore so it was safe to drill ahead were all rooted in the operational procedures implemented prior to spudding the well. This stresses the effectiveness that well thought out operational procedures based on solid technical reasoning can have in drilling operations.

3.1.2 Well ESS-107, Atlantic Ocean, Offshore Brazil

Lage et al. (2002) published a case study detailing the 1-ESS-107 deepwater exploratory well drilled in 4,220 feet of water in the Espírito Santo basin offshore Brazil. The well encountered what was believed to have been two separate overpressured intervals in which influxes occurred, as well as wellbore breathing coupled with hydrocarbon swap-out, in a single hole section. The well control situation, which resulted from these incidents, lasted 13 days and the well ultimately had to be temporarily abandoned due to hydrate formation in the choke and kill lines. After pulling the BOP and changing mud systems, the well was reentered and successfully drilled to TD with the use of an additional liner string. Figure 3.5 below displays the well's location roughly 37 miles off the Brazilian coast and roughly 21 miles from nearest producing field, the Peroá field.

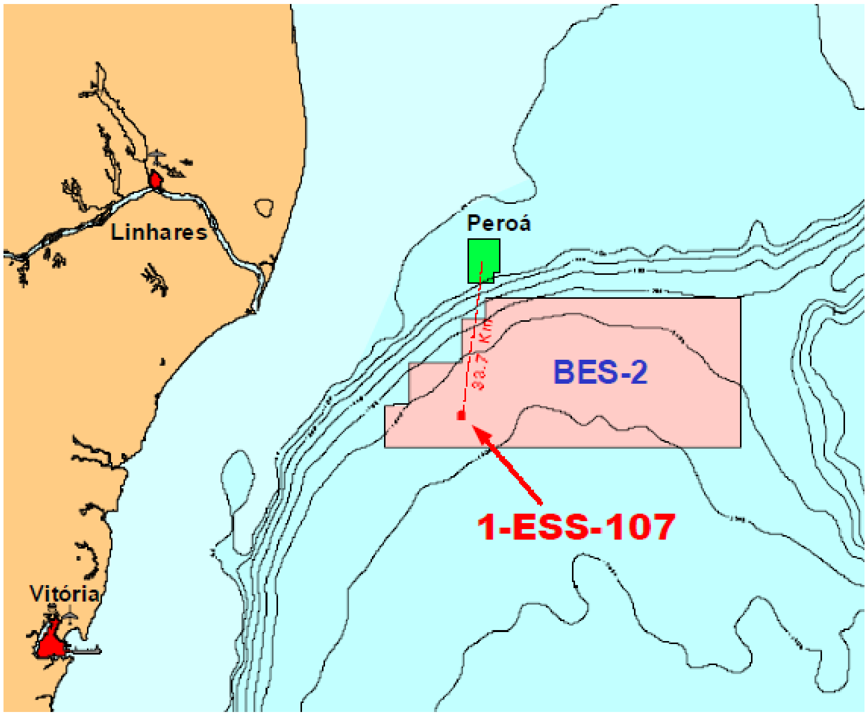

Figure 3.5: 1-ESS-107 well location offshore Brazil (Lage et al., 2002)

Lage et al. (2002) details the well plan as a 3-string design using a conventional water based mud and a TD of 16,290 ft. The well was drilled without incident to a depth of 15,483 feet when a drilling break occurred, a pit gain of 10 barrels was detected, and the stand pipe pressure dropped, indicating an influx had occurred. A flow check was performed and an additional 25 barrel pit gain occurred, so the well was shut in. The SIDPP was eventually measured at 620 psi after circulating the kick out and the decision was made to increase the mud weight to 12.5 ppg. This was the initial sequence in a well control event that lasted over the next five days. Figure 3.6 displays the shut-in pressures and the change in BHP due to mud weight over this period.

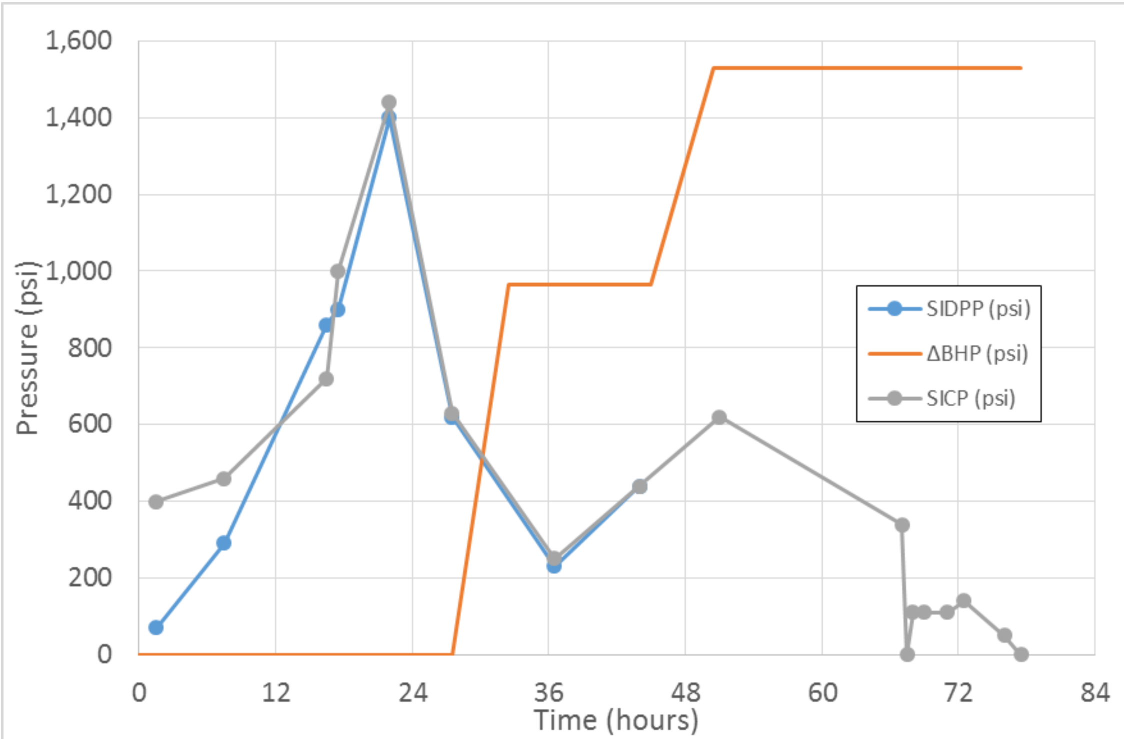

Figure 3.6: Pressures during first well control event (Data from Lage et al., 2002)

As can be seen in Figure 3.6, the mud weight was increased twice during this sequence, first from 11.3 to 12.5 ppg and then from 12.5 to 13.2 ppg. Lage et al. (2002) explained that the initial kill mud weight was calculated using the 620 psi SIDPP while the second increase in mud weight was deemed necessary due to heightened shut-in pressures after circulating the initial kill mud. The magnitude of the second increase was assumed rather than calculated as there was difficulty obtaining a SIDPP due to a blind flapper valve in the drill string After the circulating the 13.2 ppg mud into the hole, shut-in pressures were still present but at lower values than before. Furthermore, these pressures were believed to be associated with trapped pressure as the SICP was bled to zero multiple times.

Lage et al. (2002) states that drilling was resumed and the well was deepened from 15,483 to 15,834 feet over the next two days. Throughout this hole-section, while no net pit gains occurred, heavy gas cuts (up to 30 %) were recorded and each was associated with the bottoms up time for a connection. A flow check after the first gas cut at surface showed a static well, but a flow check after the fourth gas cut at surface registered a 10 barrel gain over 75 minutes. The mud weight was subsequently increased to 13.5 ppg, but heavy gas cuts associated with bottoms up from static conditions continued, so the mud weight was increased further to 13.7 ppg. Gas cuts continued with this mud weight, but several flow checks indicated the well was static and therefore overbalanced. After tripping the string out of the hole to the BOP at a controlled pace to avoid swabbing, several influxes occurred totaling 128 barrels and the well was shut-in. Preparation for the static volumetric method was in progress when the kill line and subsequently the choke line became plugged with what was believed to be hydrates caused by free gas and low temperatures at the BOP (Lage et al., 2002). Cement was then bullheaded down the casing string to temporarily abandon the well and the BOP was pulled to clear the choke and kill lines. The BOP was then run again and the well was reentered and successfully drilled to TD with the use of a SBM and the setting an additional 7” liner string.

In review of the well, Lage et al. (2002), discussed a low permeability overpressured reservoir or wellbore breathing coupled with hydrocarbon swap-out as the two potential mechanisms behind the influxes and concluded that it was likely a combination of the two. Lage et al. suggested that overpressure was present based on:

- Increased rate of penetration (ROP) indicated an increase in formation pore pressure at 15,483 feet, the depth of the first kick
- Increased ROP indicated an increase in formation pore pressure between 15,716 feet and 15,834 feet, the depth of the second kick
- Sandstone cuttings impregnated with oil were identified at surface when bottoms up occurred for the 15,716-15,834 interval indicating a sandstone reservoir was present.

Lage et al. suggested that wellbore breathing coupled with hydrocarbon swap-out was also present based on:

- The volumes of fluid returns during bleed off were significantly larger than mud compressibility data indicated should be returned (3.3 bbl/100 psi vs. 1 bbl/100 psi), which indicates that the elastic closure of fractures was contributing volume to the system
- After the mud weight was raised following the first kick, SIDPP and SICP were bled to zero multiple times indicating overbalance. However, gas shows continued at surface indicating hydrocarbons were still entering the wellbore
- For the drilled interval, bottoms up for each connection consistently had associated gas peaks at surface indicating that gas entered the wellbore when pumps were stopped.
- Significant volumes of gas were recorded at surface, but there were no associated pit gains detected.

- Losses during drilling were not explicitly mentioned by the authors, but the above bullet points and the assessment that hydrocarbon swap out is present are consistent with the wellbore breathing mechanism in which fluid flows into fractures during drilling and back into the wellbore during connections. Losses may not have been noticed at surface and recorded in the daily operational report if they occurred slowly over the course of drilling a stand of pipe. This could potentially explain the lack of fluid losses being mentioned in the paper.

In addition to the reasons mentioned above, there are several other data points indicating that the wellbore breathing was present in this case study. First, shortly after the initial mud weight increase following the first influx at 15,483 feet, the SIDPP and SICP were measured at 440 psi. In light of this, the decision was made to raise the mud weight further and to circulate the well with the current 12.5 ppg mud while the heavier mud was prepared. During this 5 ½ hour time period the well was circulated through the choke line while holding an additional 230 psi of back pressure at the choke. The SIDPP couldn't be measured due to the blind flapper valve but the SICP was measured as 620 psi, a 180 psi increase over the prior measurement. If the well were underbalanced, the additional pressure by the choke would have resulted in either the same or slightly lower SICP. The increased shut in pressure indicates that the increased bottom-hole pressure during circulation likely exacerbated the problem, indicating wellbore breathing was likely responsible. A pressure bleed off sequence combined with a flow check at this point, prior to weighting up to 13.2 ppg mud, could have been useful in identifying the mechanism.

Second, increases in mud weight following the second influx have no impact on the gas cuts observed at surface. In fact, the 40 percent gas cuts seen in the later part of the well control incident were actually the highest seen over the incident. This indicates that the higher mud weights employed at this point may have been making the problem worse rather than better, consistent with wellbore breathing coupled with hydrocarbon swap-out. Figure 3.7 below displays surface gas cut readings as well as the mud weight changes over the five days following the second kick.

Figure 3.7: Mud weight and gas cuts after kick at 15,834 ft. (Data from Lage et al., 2002)

Last, there were significant pit gains over the last day and a half of the well control incident in spite of a higher mud weight. These occurred after the mud weight had been increased to its highest level, 13.7 ppg, and after the drill string had been tripped out of the well to the BOP at 4,137 feet. The trip out of the hole took a total of 24 hours due to a controlled trip velocity to avoid swabbing and a complete BOP test. Over this time period, the well was in static conditions or near static conditions as no circulation occurred. Because of this, any downhole fractures responsible for the earlier wellbore breathing events would have been filled with drilling fluid as static pressures were now similar to circulating pressures earlier in the well control event. As the mud in the lower part of the well was no longer being replaced with mud from surface, the formation in contact with the mud would have been warming back to in-situ conditions throughout this period. The warming would increase the effective fracture gradient and result in some fracture closure, forcing drilling fluid into the wellbore and resulting in a gain at surface. An overpressured low permeability zone could cause slow pit gains like these, but similar gains would have been expected to occur throughout the static period rather than only at the end. Furthermore, if the well was still underbalanced with 13.7 ppg mud, fluid gains should have been experienced earlier in the well control sequence when lighter muds were in the hole. Therefore, taking all the available data into account, the fluid gains during static conditions late in the well control event were likely driven by thermal effects as the formation warmed back to in-situ conditions, increasing the effective fracture gradient of the downhole formation and closing fluid filled fractures.

3.1.3 Well 22/30 C-10, North Sea, Offshore Scotland

Maury and Idelovici (1995) published a case study detailing the 22/30 C-10 well targeting the Elgin Field located in the North Sea, 143 miles east of Aberdeen, Scotland. The well is unique in that it was drilling in HPHT conditions and was using a heat exchanger to keep the OBM below the flash-point at surface for safety reasons. This combination of high temperature subsurface conditions and a cooled mud system led to significant thermally induced effective stress changes downhole. The well encountered significant wellbore breathing, connection gas, and thermally driven pit gains during static conditions while drilling the Kimmeridgian clays overlying the targeted reservoir. These events led to a loss of 30 rig days and required the setting of a contingency liner to ultimately reach TD.

Maury and Idelovici (1995) describe the well as being drilled without issue through 16,913 feet TVD when increased connection gas, as well as slight flow during flow checks, was encountered and continued unabated despite several mud weight increases. Displayed in Figure 3.8 below, this series of events transpired over a four day period and culminated in a maximum connection gas measurement of 48 percent. Maury and Idelovici also mention that the increases in mud weight resulted in longer periods of flow during flow checks prior to eventual stabilization at static conditions.

Figure 3.8: Gas cut and mud weight increases (Data from Maury and Idelovici, 1995).

The decision was then made to trip out of the hole, but multiple short trips, flow checks, and bottoms up circulations were performed to ensure that the well was overbalanced prior to tripping out to surface (Maury and Idelovici, 1995). These events are shown in Figure 3.9. Continued flow was observed during flow checks performed at the shoe while flow checks at bottom-hole resulted in static conditions being reached after about an hour. Complete circulation of the well was carried out several times and although no formation fluid was found to have entered the well, significant gas reading were measured. The well was eventually deemed stable and the pipe tripped out of the hole, but slight flows, similar to those observed at the casing shoe during short trips, were observed at flow checks throughout the trip. Once the bit was at surface and a complete BOP test had been performed, it was observed that mud was flowing out of the well so it was shut-in with an initial SIDPP of 400 psi increasing to 600 psi over four hours. The well was eventually reentered, determined to be overbalanced, and drilled to TD after setting an additional liner.

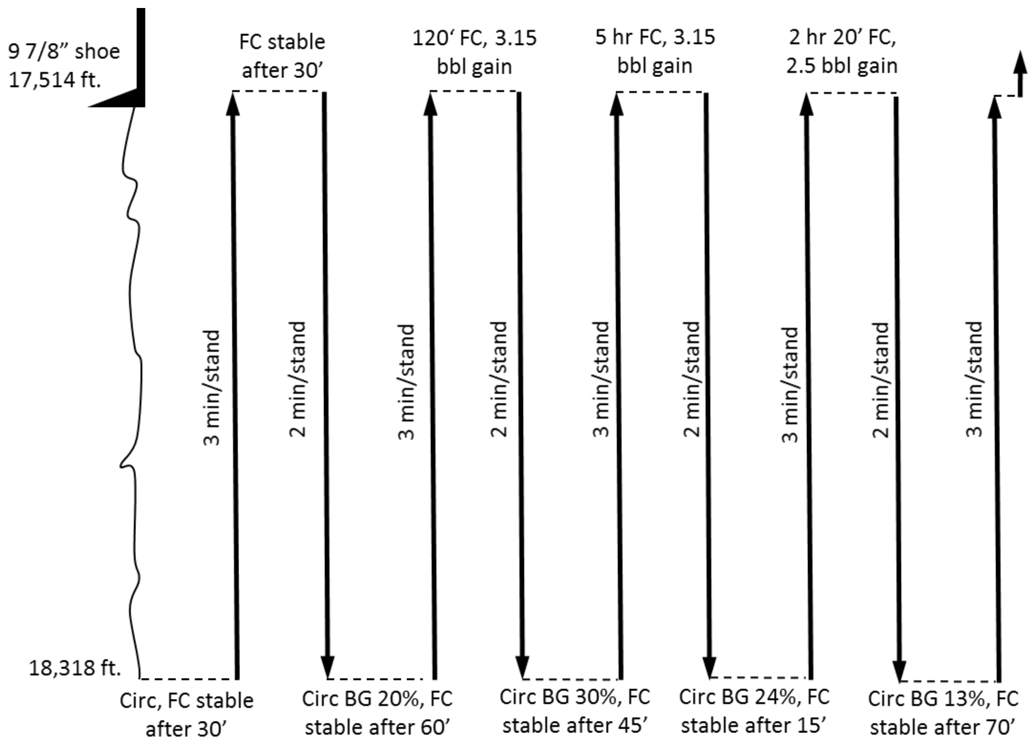

Figure 3.9: Log of events during short trips prior to pulling out of the hole (Data from Maury and Idelovici, 1995).

In review of the well, Maury and Idelovici (1995) incorporated numerical modeling to evaluate the borehole stresses stress changes due to thermal effects and suggested that the mechanism involved was fracture initiation and propagation due to cooling and subsequent mud weight increases followed by fracture closure as the formation returned to thermal equilibrium. Additionally, Maury and Idelovici (1995) attributed the increased gas cuts experienced during the initial sequence to near wellbore vertical fractures, caused by both cooling and subsequent mud weight increases, forming around the circumference of the wellbore and enabling some gas to enter the OBM.

While the fluid gains that occurred while tripping and the shut-in pressures recorded at surface were likely driven by thermal effects as the downhole formation returned to thermal equilibrium, the connection gas and fluid gains during flow checks early in the well control sequence were likely not caused by the same mechanism. While the increased gas cuts were likely related to fractures, the assertion by Maury and Idelovici that the gas cuts were caused by fractures around the circumference of the wellbore is incorrect. The models prediction of fractures around the circumference of the wellbore is rooted in the incorrect assumption of isotropic horizontal stresses. This region of the North Sea has anisotropic horizontal stresses based on observed wellbore tensile fractures and wellbore breakouts (Zoback, 2007) and (Heidbach et al., 2008).

The underlying mechanism causing the fluid gains and gas cuts during the early sequence shown in Figure 3.8 was likely wellbore breathing in which gas was diffusing into the OBM within the fractures while circulating and then being brought back into the wellbore with the drilling fluid when circulation was stopped. The fluid gains and gas cuts experienced during the short trips and trip out to surface were likely caused by a combination of the above mechanism and closure of fractures due to thermal effects as the formation returned to thermal equilibrium during static conditions. The reasoning for these conclusions are explained in the following paragraphs.

Flow check behavior early in the sequence differed significantly from late in the sequence: early flow checks resulted in flow immediately after pumps were shut off and then became static after 25-45 minutes while flow checks at the casing shoe during the short trips, during the trip out to surface, and once the bit was at surface resulted in continued flow over long periods of time. During the short trip sequence, flow checks performed at bottom-hole eventually went to static conditions while flow checks performed at the casing shoe did not. This can be explained because each flow check at bottom-hole during the short trips and during the initial well control sequence occurred immediately following circulation. Circulation would have charged the fractures with cold mud from surface and when the pumps were shut off for the flow check, the reduction in wellbore pressure would have caused some fracture closure and some mud to flow back into the wellbore. Thermal effects likely would not have time to take effect during the subsequent 25-45 minute flow check because cold mud had just been forced into the fractures and the heat diffusion required to warm the fluid and the surrounding formation is a slow process. The flow checks performed at the casing shoe during the short trip sequence were each performed after the well had been static for between 1-3 hours (each occurred after a bottom-hole flow check and the string had to be tripped 800 feet to the shoe). This time lag would have provided some time for heat diffusion and the associated thermal effects to initiate and would explain the continuous small flow volumes observed at the casing shoe. Furthermore, the continuous small flow volumes were also seen during flow checks while tripping out to surface and the pressure build up at surface was gradual and occurred over a four hour period. This is consistent with thermal effects as it would be a slow process which would continue until the formation surrounding the fractures returned to thermal equilibrium.

The fact that the connection gas observed during the initial well control sequence was not lessened and increased with higher mud weights indicates that it was caused by wellbore breathing coupled with gas diffusion into the OBM. During circulation, some OBM would have been forced out into the fracture system and exposed to the gas bearing formation where gas diffusion could take place. When circulation was stopped, this OBM as well as the dissolved gas entrained in it, would flow back to the wellbore and be circulated up the annulus when pumps were started again. Furthermore, this effect would be exacerbated by mud weight increases because this would propagate the fracture and allow a larger volume of the OBM to come into contact with the gas bearing formation. Also, the gas diffusion process is driven by the high partial pressure of the formation gas compared to the low partial pressure of gas in the OBM so while increased overbalance caused by mud weight increases would influence diffusion, it would not be significant (Bradley et al., 2002).

Chapter 4: Identification, Mitigation, and Prevention of Wellbore Breathing

4.1 Identification of Wellbore Breathing

This section will discuss identification of wellbore breathing, differentiation between breathing and kicks, and time dependent variables which tend to inhibit identification at surface. In addition, the section also details methods for drilling ahead once wellbore breathing has been identified.

4.1.1 Flowback Fingerprinting

Flowback fingerprinting involves recording the mud returns to the pits following pump shut offs at connections and using these to develop a flowback "fingerprint" or "signature" which can be used to identify any abnormalities in flowback going forward. The primary abnormality being monitored for is an increase in either the rate of flowback or the total volume of flowback as this would indicate an influx or wellbore breathing had occurred. The typical method for this involves the mud logger plotting the flowback rate or cumulative pit gain versus time for each connection as can be seen in Figure 4.1. The mud logger then uses these plots to characterize the flowbacks, estimates the threshold of an abnormal flowback based on past experience, and manually sets an alarm at this threshold (Ali et al., 2013). While this has been successfully implemented to identify influxes in the past (Weisinger et al., 2000), it introduces the potential for human error in the quantification of an abnormal flowback. For example, on the Gulf of Mexico well displayed in Figure 4.1, the alarm was set at too high of a level which resulted in completely missing the minor influx and would have resulted in missing the major influx had the field engineer not manually identified it (Ali et al., 2013).

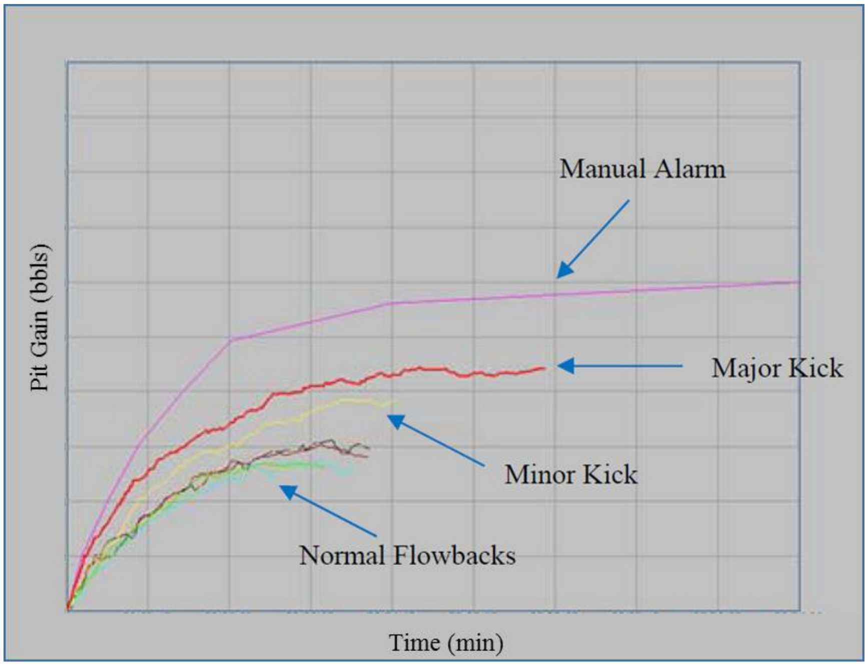

Figure 4.1: Flowback monitoring system (Modified after Ali et al., 2013)

As a result of the rig time lost due to this influx, Ali et al. (2013) developed Smart Flowback Fingerprinting using statistical analysis and interpretation of flowback data to set alarms in place of the manually set alarm system. Smart Flowback Fingerprinting calculates the average and standard deviation of past flowback curves and uses these to define alarm curves.

The average is:

$$\mu = \frac{1}{N} \sum_{i=1}^{N} x_i \tag{4.1}$$

And the standard deviation is:

$$\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(x_i - \mu)^2} \tag{4.2}$$

Where,

$x_1, x_2 \ldots\ldots x_N$ = the last N flowbacks

The alarm can then be set at whichever multiple of the standard deviation is desired. Ali et al. (2013) states that 95 % of all previous flowbacks fell within two standard deviations of the mean for the well examined and the system would have caught the minor kick within 70 seconds and the major kick immediately as shown in Figure 4.2.

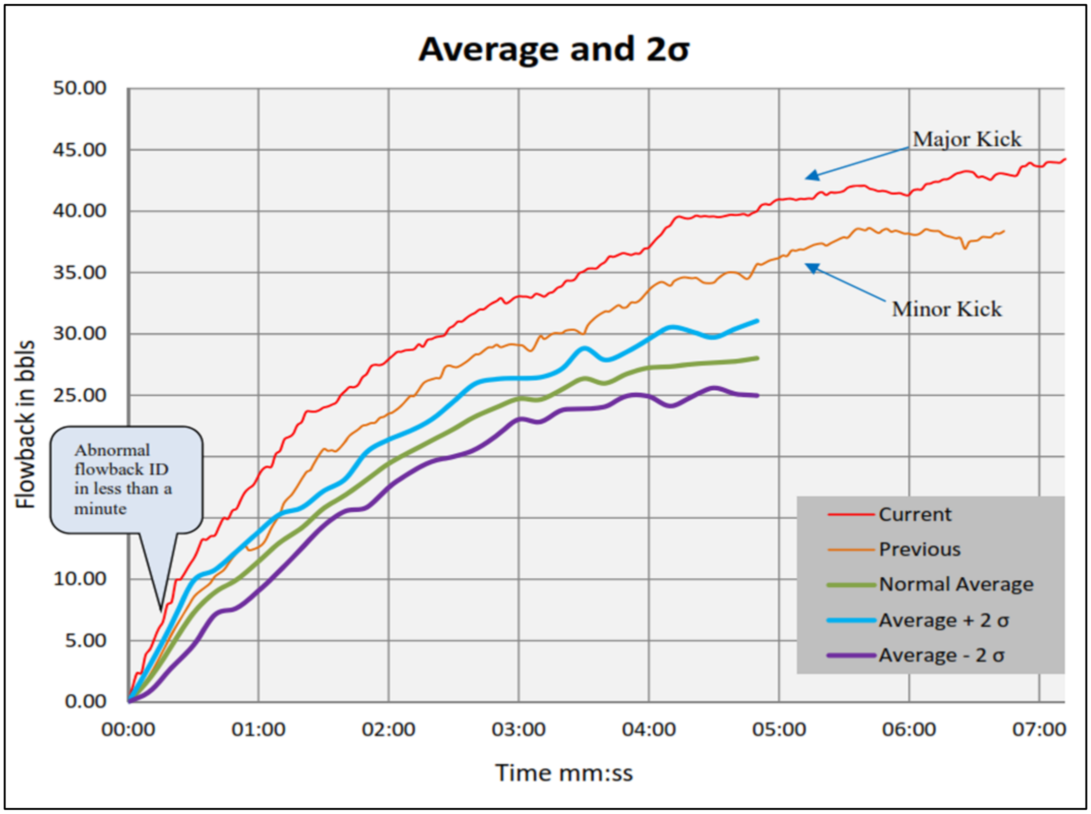

Figure 4.2: Smart Flowback System plot (Ali et al., 2013)

While this Smart Flowback Fingerprinting system was developed primarily for identification of kicks, it would also identify the initiation of wellbore breathing as flowback volumes would increase. On the initial increased flowback, it would be difficult to determine whether an influx or breathing had occurred so a flow check would likely be required. Following the identification of wellbore breathing, flowback fingerprinting could also be useful. In this case, the wellbore breathing flowback would be characterized and the Smart Flowback Fingerprinting system could identify increased flowback indicating a kick had occurred or a decreased flowback indicating that lost circulation had been initiated.

4.1.2 Pressure While Drilling Measurements

Ward and Clark (1998) first introduced the pressure while drilling (PWD) tool as a means to differentiate between wellbore breathing and an influx occurring. Data from connections on a Gulf of Mexico well, which can be seen below in Figure 4.3, was presented to show the downhole pressure behavior in time during wellbore breathing. The left side of Figure 4.3 shows the downhole pressure behavior of a well during a typical connection. When the pumps are shut off, the pressure immediately drops from the ECD of 16.26 ppg to the ESD of 15.92 ppg. When the pumps are brought back on after making the connection, the pressure immediately returns the ECD of 16.26 ppg. The right side of Figure 4.3 shows the downhole pressure response of the same well during a connection once wellbore breathing has started. When the pumps are shut off, there is a gradual decrease in pressure from the ECD to the ESD rather than the immediate drop seen on the conventional connection. The gradual pressure decline is due to mud flowing out of the fractures and back into the wellbore, preventing the rapid decrease seen without breathing (Ward and Clark, 1998). When the pumps are started back up, there is a gradual increase back to the ECD due to fluid flowing back into the fractures. As can be seen, the pressure profile for the connection without breathing is square shaped whereas the pressure profile with breathing exhibits more of an irregular rounded shape. These pressure profiles make for easy identification of breathing and the rounded pressure profile is often call a "shark fin" profile due to its obvious resemblance.

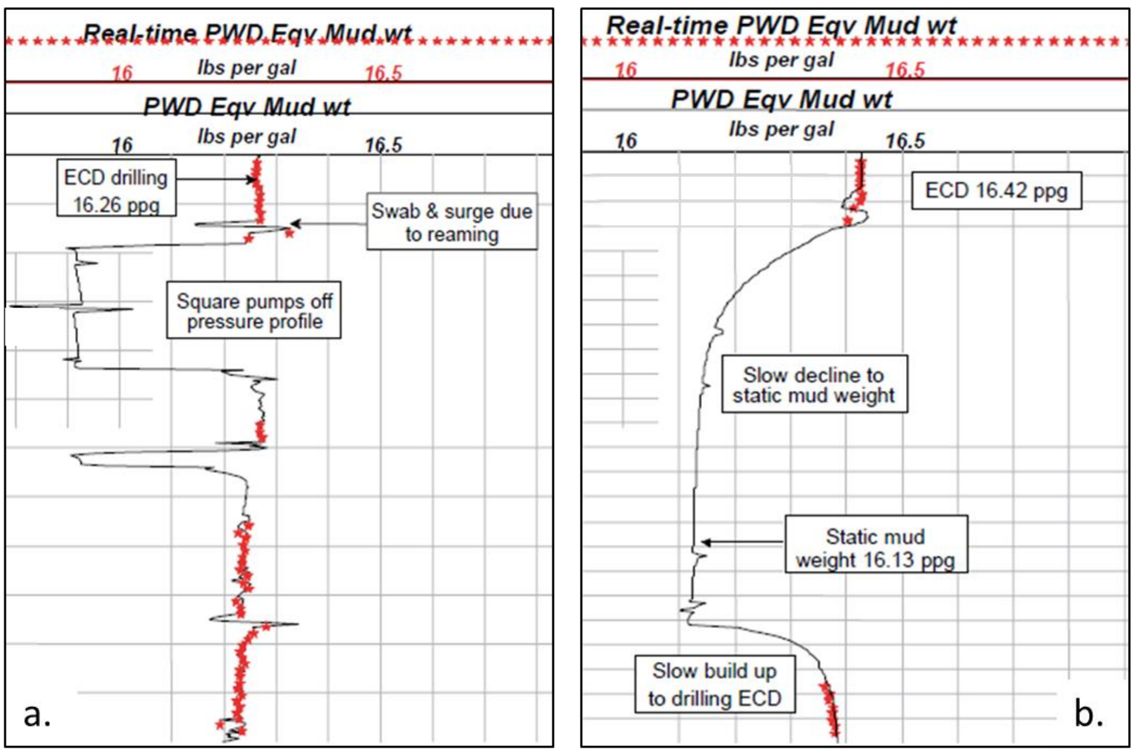

Figure 4.3: (a.) Pressure behavior during conventional connection. (b.) Pressure behavior during connection with breathing. (Ward and Clark, 1998)

The primary issue with the application of PWD for identification of wellbore breathing while drilling, is the inability to get real-time data to surface. Currently, the widely used technology for transmitting downhole data to surface is mud pulse telemetry (MPT), which creates pressure pulses as mud flows through the drill string to transmit the data. The primary drawbacks to this system include: no data transmission when pumps are off, difficulty in transmitting data in extremely deep wells, and limited bandwidth (McCartney et al., 2009). Due to these drawbacks, large amounts of data must be stored in memory downhole and downloaded whenever the BHA is brought back to surface. As a result, the analyzation method described by Ward and Clark (1998) cannot be performed until the data is downloaded at surface. Therefore, while useful in the characterization of the wellbore breathing mechanism, this method is not suitable for real-time differentiation of kicks and breathing events using the current industry standard MPT system.

One additional method for identification of wellbore breathing would be to perform step rate changes in fluid circulation rates while monitoring PWD measurements. A step down in flow rate would decrease the ECD similarly but to less of an extent than at connections and data could still be transmitted to surface through the flowing mud stream. If breathing were occurring, the reduction in ECD would allow some fluid to flow back into the wellbore and the downhole pressure should exhibit a rounded profile as it transitions to a lower pressure. Conversely, if no breathing were occurring, the transition should be more of an abrupt drop to the lower pressure. The primary issue with this approach would be the minimum flow rate required to transmit data to surface in a MPT system. If the circulation rate being used during drilling was not significantly higher than the minimum rate, the step down in pressure would be small and likely inhibit differentiation between a square or rounded transition profile.

In recent years, advances have been made in wired drill pipe technology enabling high speed, large bandwidth transmission of downhole data to surface in real-time. The technology has been successfully implemented in field tests with encouraging results (Edwards et al., 2013), but has yet to be widely incorporated within the drilling industry. Once implemented, wired drill pipe can enable real-time monitoring of downhole pressures during connections and therefore real-time differentiation between wellbore breathing and formation fluid influxes.

4.1.3 Logging While Drilling Measurements

Bratton et al. (2001) presented a method for identification of wellbore breathing in wells drilled with an OBM or SBM using resistivity measurements. Because resistivity tools measure the resistance to electrical current, fractures filled with a nonconductive fluid like OBM or SBM will artificially increase the resistivity reading of the formation. The method proposed by Bratton et al. identifies these artificially increased resistivity measurements and correlates them to different stages of fracture propagation and closure.

An increased shallow resistivity measurement compared to the deep resistivity measurement for a formation indicates that there are drilling fluid filled fractures extending from the wellbore, but these fractures do not extend far enough to influence the reading of the deep resistivity measurement. An example of such behavior from a GOM well shown by Bratton et al. can be seen below in Figure 4.4. Between 5,655 and 5,700 feet, the shallow resistivity with a 16 in. depth of investigation registers a significantly larger resistivity than the deep resistivity with a 40 in. depth of investigation. While not specific to wellbore breathing, this method can reveal fractures before large losses or wellbore breathing have occurred, enabling preemptive action to prevent such issues.

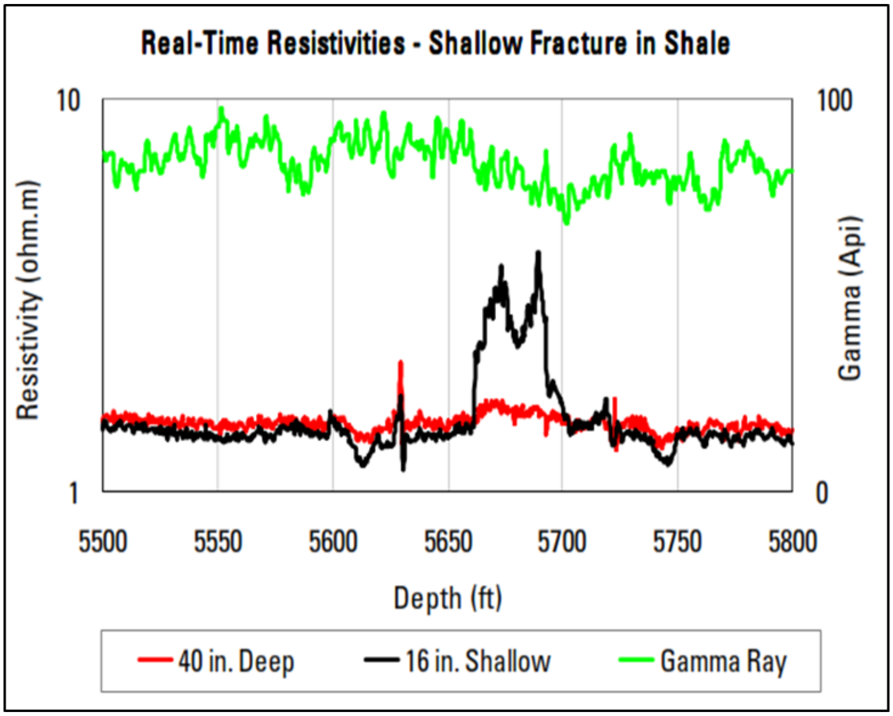

Figure 4.4: Resistivity plot revealing shallow mud filled fracture (Bratton et al., 2001)

The second method presented by Bratton et al. (2001) uses time-lapsed resistivity measurements to identify the opening and closing of a drilling fluid filled fracture during the wellbore breathing process. This can be identified by a higher resistivity for a given depth when the ECD is higher and a lower resistivity reading for the same depth when the ECD is lower, indicating a closing fracture, as shown in Figure 4.5 below. The black line registering the highest resistivity was logged while drilling with an ECD of 13.1 ppg. The red line and the yellow line were logged a short time later when circulating off bottom with ECD's of 12.7 and 12.6 ppg respectively. The lowest resistivity, the turquoise line, was logged once the pumps had been shut down and is indicative of the actual formation resistivity. The graphic at the bottom of the figure depicts the fracture closing as the wellbore pressure is reduced and is color coded to correspond with the respective resistivity measurement for each stage of fracture closure.

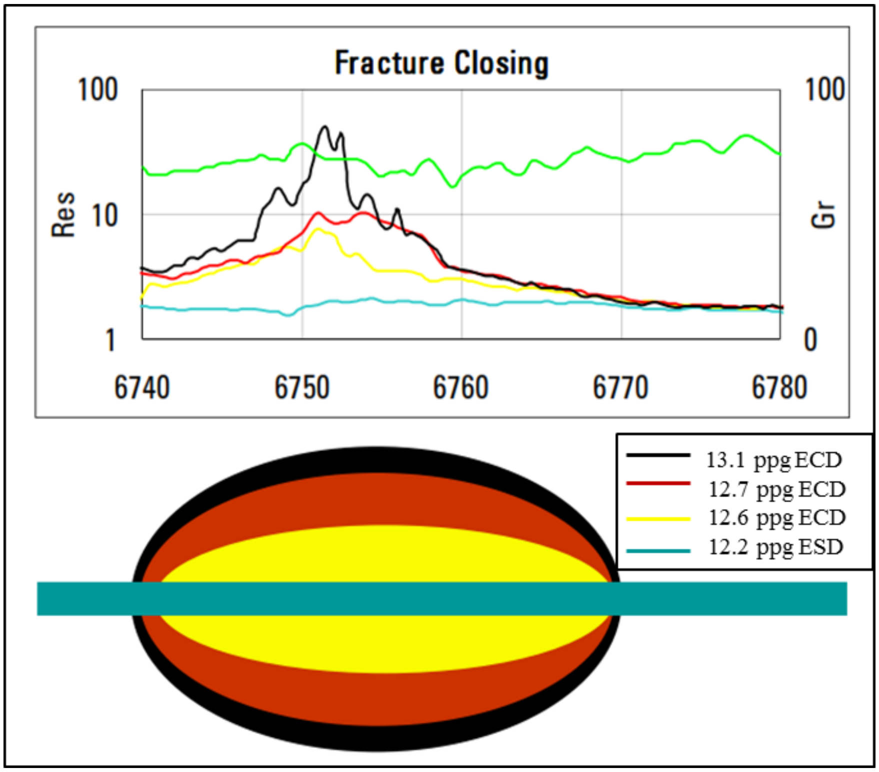

Figure 4.5: Time-lapsed resistivity plot showing fracture closure (Bratton et al., 2001)

While using resistivity measurements to identify wellbore breathing and shallow wellbore fractures can be effective in some cases, there are a few limitations worth mentioning. Similar to the PWD tool, LWD tools also rely on mud pulse telemetry to transmit data so real-time resistivity logs would only be available at surface when circulating. Additionally, it may be difficult to identify the closure of a fracture if it has been propagated a significant distance away from the wellbore and outside the depth of investigation for the resistivity tool. In this case, some fracture closure could occur near the fracture tip but this would likely have little effect on a resistivity measurement taken closer to the wellbore. Last, unless LWD is being employed specifically to identify and locate wellbore breathing, sections of the wellbore are not typically logged multiple times with different ECD's.

4.1.4 Time and Temperature Dependent Variables

Time and temperature dependent effects are often unaccounted for or neglected during drilling operations and can lead to misidentification of the downhole mechanism responsible for processes observed at surface. This section details these variables and provides examples from published case studies to demonstrate the effects these variables can have in regards to wellbore breathing.

4.1.4.1 Thermally Induced Stress Changes due to Drilling Fluid Temperatures

Thermal effects on stresses around the wellbore can have a significant effect on the effective fracture gradients of formations. These thermal effects are extremely important in HPHT wells, especially when the conditions at surface are cold. This is because the cold mud from surface will result in a significant reduction in the formation temperature and hoop stress, as shown in equation 2.4. Alaska and North Sea wells often exhibit these conditions and care should be taken to monitor drilling fluid temperatures in such environments. When drilling a hole-section, the mud circulated into the well from surface is significantly cooler than the in-situ temperature of the formation. This results in cooling of the formation in the lower portion of the well near the bit and warming of the formation higher up in the wellbore (Karstad, 1998) as shown in Figure 4.6.

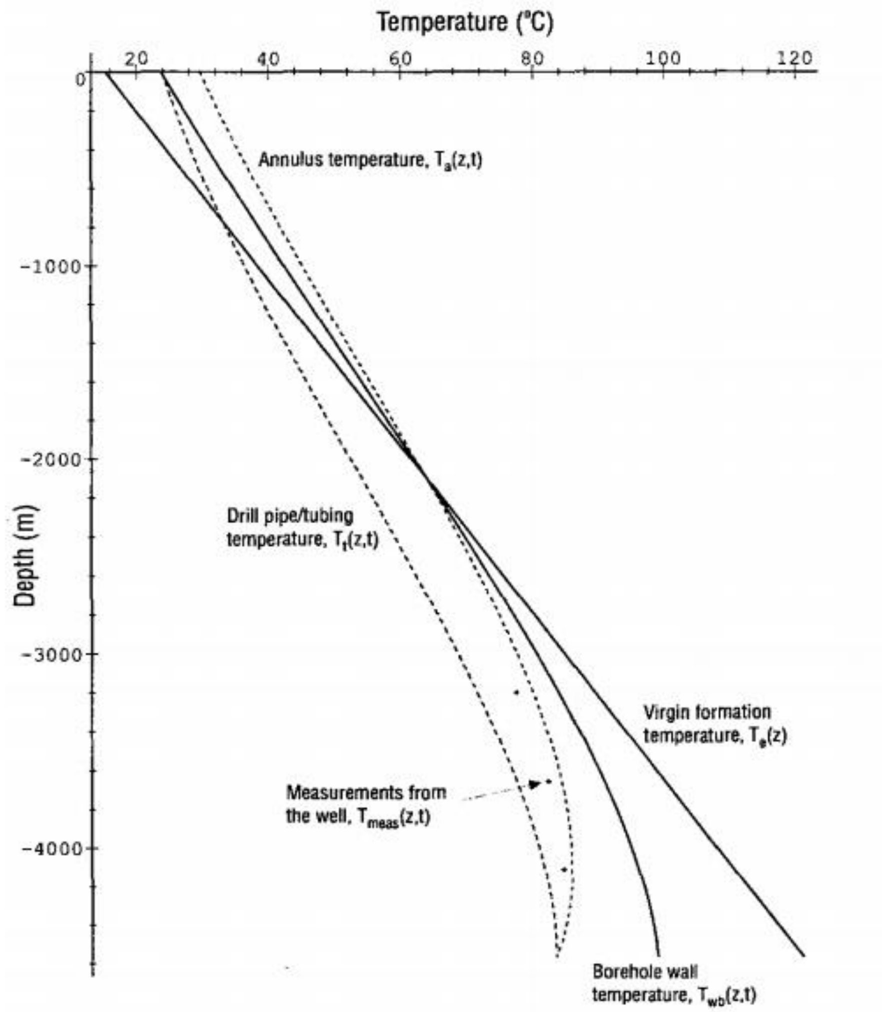

Figure 4.6: Various temperatures in a well during drilling (Karstad, 1998).

In an effort to quantify the effect of such temperature changes, Pepin et al. (2004) performed three leak off tests with different stabilized downhole temperatures and determined that there was a change in fracture gradient of 0.16 ppg/10° F. Although this test was for a single formation, it is indicative of the negative effects that formation temperature reductions can have on effective fracture gradients. This phenomenon has been well documented in literature (Schmidt et al. 1999) and can be approximated for a given formation using a linear elastic model (Fjaer et al., 2008).

$$\Delta\sigma_t = \frac{E \propto_t (T - T_f)}{1-\upsilon} \tag{4.3}$$

where,

E = Young's Modulus

$\propto_t$ = linear thermal expansion coefficient

υ = Poisson's Ratio

T_f = original formation temperature

While most literature pertaining to reductions in fracture gradients due to thermal effects have focused on lost circulation events, thermal effects can also contribute to wellbore breathing. The North Sea case study detailed earlier in this work by Maury and Idelovici (1995) discussed a wellbore breathing event believed to be entirely driven by thermal stress changes. In this case, the mud losses were likely very hard to identify because cooling of additional extents of the formation would be required each time the fracture propagated, making it a slow and gradual process. Also, the formation would need to warm back up in order for the fracture gradient to increase and cause mud backflows. This delays the gains significantly from the losses, making identification of the thermal mechanism responsible extremely difficult.

In cases where the fracture gradient is initially higher than the wellbore pressure until it has been sufficiently cooled by drilling fluid, the fracture would initiate up-hole from the bit. This is because the portion of the wellbore wall cooled most by the drilling fluid occurs uphole of the bit, as shown in Figure 4.6. This will make identification of the loss zone difficult as it would likely be diagnosed as occurring in the formation closest to the bit. This can lead to difficulties in remediation as LCM and cross-linked pills typically need to be placed across the loss interval to be effective.

Last, the casing shoe is usually identified as the weakest point in the open-hole section as the minimum horizontal stress is related to the overburden and typically increases with depth (Zoback, 2007). Therefore, the maximum pressure from the FIT or LOT performed at the casing shoe defines the upper limit of mud weight that can be used in the hole-section. However, this does not take into account thermal effects which may alter the strength of the formation at the casing shoe either during the LOT or afterwards, as the hole is being deepened. As shown by Karstad in Figure 4.6, the borehole wall's temperature actually increases in the upper part of the well during drilling as mud that was warmed near the bottom hole is circulated up the annulus. Depending on the length of a given hole-section, the casing shoe may see an increase in temperature which would raise its effective fracture gradient. This would likely invalidate the assumption that the casing shoe is the weakest point in the wellbore and could increase or decrease the effective fracture gradient for the wellbore, depending on rock properties and thermal effects elsewhere in the hole-section.

4.1.4.2 Downhole Pressure Variations

Another variable, which is often unaccounted for, are increases in annular pressure which periodically occur during drilling operations. Typical causes for such pressure increases include increased cuttings loading, barite sag, or restrictions in the annulus. Each of these three causations are due to downhole processes and may not be recognized at surface. These pressure increase events, however gradual or seemingly insignificant, can initiate wellbore breathing if they exceed the fracture pressure. One such incident was published by Edwards, Bratton, and Standifird (2002) and is shown in Figure 4.7 and discussed in detail below the figure.

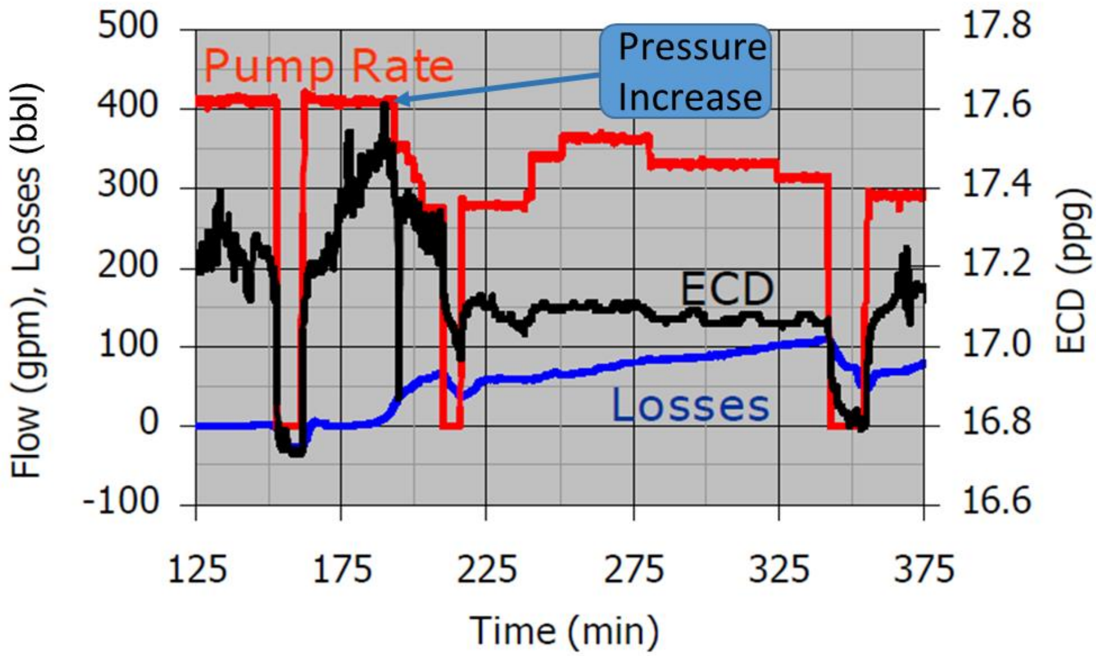

Figure 4.7: Initiation of wellbore breathing (Modified after Edwards, Bratton, and Standifird, 2002)

Starting at the left side of the figure, drilling is in progress with a flow rate of 400 gallons per minute (gpm) in red, an ECD of roughly 17.25 in black, and zero cumulative losses in blue. Circulation is stopped for a connection at the 150 minute mark, with an immediate drop in ECD and the accustomed flowback signature for the well of 20 bbl. When pumps are started back up and return to 400 gpm, annular pressure behaves abnormally and spikes slightly above 17.6 ppg. Losses were initiated at this point so the flow rate was decreased in order to reduce the annular pressure. The pumps were next shut off at the 210 minute mark to make a connection. The slow decline in ECD at this connection indicates that wellbore breathing is occurring, but pumps were started back before any significant pit gain was seen at surface. Losses continued throughout this stand, even at a lower ECD than had been used with no losses prior to the pressure spike. This likely occurred because the fracture gradient was exceeded and a fracture initiated at the wellbore wall. Once a fracture has been initiated, the mud pressure must only exceed the minimum horizontal stress to open the fracture. In this case, the wellbore pressure was also above the FPP as the continued fluid losses indicate that the fracture was being propagated. When pumps were shut off for a connection at the 342 minute mark, a 50 bbl pit gain occurred and the ECD behavior at pump shut-off confirms that wellbore breathing is occurring.

While the ECD data in Figure 4.7 is useful in confirming that wellbore breathing is occurring, the data during connections would not have been available at surface in real-time to identify the wellbore breathing. In real-time, the driller noticed the pressure increase had initiated fluid losses at the 180 minute mark and reduced the flow rate accordingly. Two connections and almost 3 hours later, a flowback 30 bbls in excess of the typical flowback signature was recorded. At first glance, this gain would appear to be a kick and the driller would likely shut the well in as a precautionary step and monitor pressures. However, a well-trained and educated on-site drilling engineer or supervisor should be able to prevent this NPT. The engineer in this case would understand the contributors to wellbore breathing, anticipate that it is a possibility in this situation, and institute a method for quick differentiation between a kick and breathing prior to the fluid gain.

4.1.5 Differentiation between Underbalance and Breathing

The most challenging aspect of dealing with wellbore breathing in drilling operations is that it exhibits characteristics very similar to those exhibited in an underbalanced or near balanced well. These similarities include pit gains, significant pressure build ups when shut in, gas cuts corresponding to connections, and hydrocarbon influxes in some cases. Key identifiers for differentiation between wellbore breathing and underbalance conditions will be discussed in this section.

4.1.5.1 SIDPP and SICP Behavior

Once a pit gain or excess flow from the well has been detected, shutting in the well via the BOP is often the next step. Once the SIDPP and SICP have stabilized, it is necessary to verify that these shut-in pressures are not being artificially increased due to trapped pressure. Artificially increased shut in pressures would result in an erroneous kill mud weight calculation. In addition to monitoring the SIDPP for the pressure response while performing bleed offs as mentioned in 2.6.11, the SICP should be monitored as well. Since the SIDPP is a direct measure of formation pressure, a reduction in SIDPP to zero during bleed off indicates that the well is not in an underbalanced state. This is the key indicator that underbalance is not the influx mechanism and should be a “red flag” that some other process is be taking place downhole. Three different potential shut-in scenarios are examined in detail here to enable better understanding of the SIDPP and SICP behavior they exhibit:

- A volume of formation fluids entered the wellbore due to the formation pressure exceeding the hydrostatic pressure applied by the current mud weight.
- A volume of formation fluids entered the wellbore due to some temporary decrease in wellbore pressure such as swabbing.
- Wellbore breathing is occurring, only drilling mud is flowing into the wellbore from the fractures.

These scenarios and their associated behavior during pressure bleed off is displayed in Figure 4.8, 4.9, and 4.10 respectively. Brown indicates drilling mud, green indicates formation fluid, and the drill string is grey.

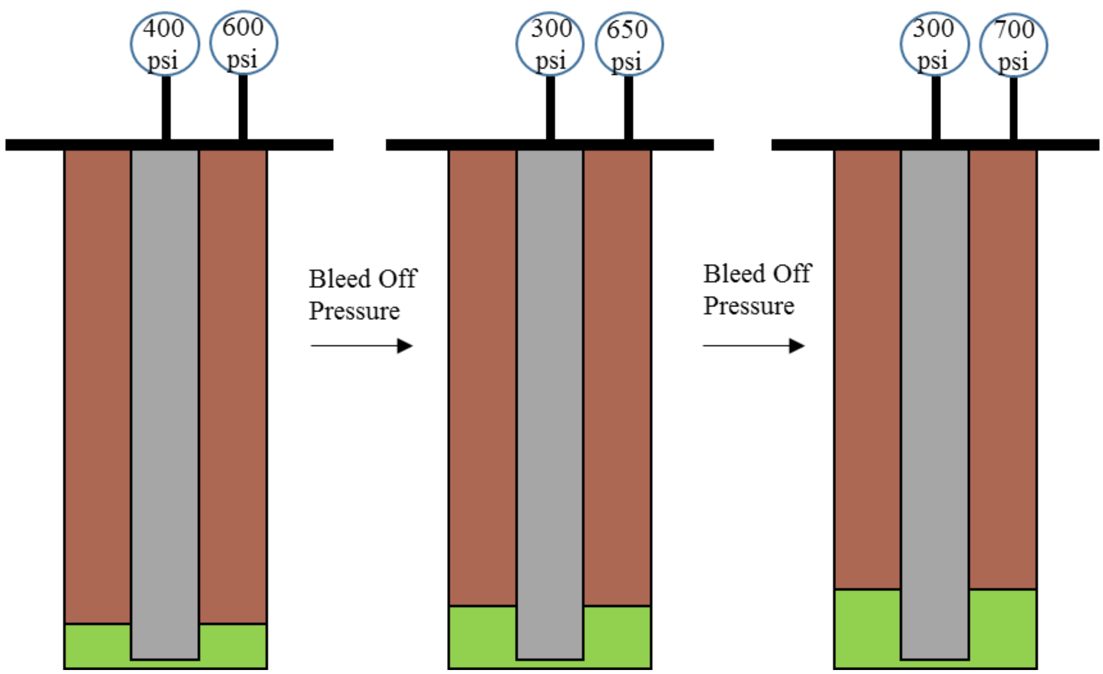

Figure 4.8: SIDPP and SICP behavior for underbalanced scenario $(P_m < P_p)$.

Figure 4.8 depicts a well that has been shut-in due to an influx caused by underbalance. On the left side, the well has just been shut in and the SIDPP is 400 psi and the SICPP is 600 psi. Pressure is then bled off to check for trapped pressure in the time between the left and middle graphics. This results in a SIDPP reduction of 100 psi, confirming trapped pressure was present. The SICP has increased because bleeding mud from the annulus allowed the influx to expand, reducing the height of the mud column, and requiring a higher surface pressure to balance the formation pressure. Pressure is then bled off again in the time between the middle and right graphics to check for trapped pressure. This time the SIDPP stays constant at 300 psi, indicating that no more trapped pressure is present and the formation pore pressure is 300 psi greater than the hydrostatic pressure provided by the mud. The SICP increases due to either more inflow from the formation or further expansion of the influx already present in the annulus. At this point, the bleed off process would be stopped because the SIDPP did not decrease after the last bleed off. Kill mud weight could now be calculated using the SIDPP and circulated into the hole to kill the well.

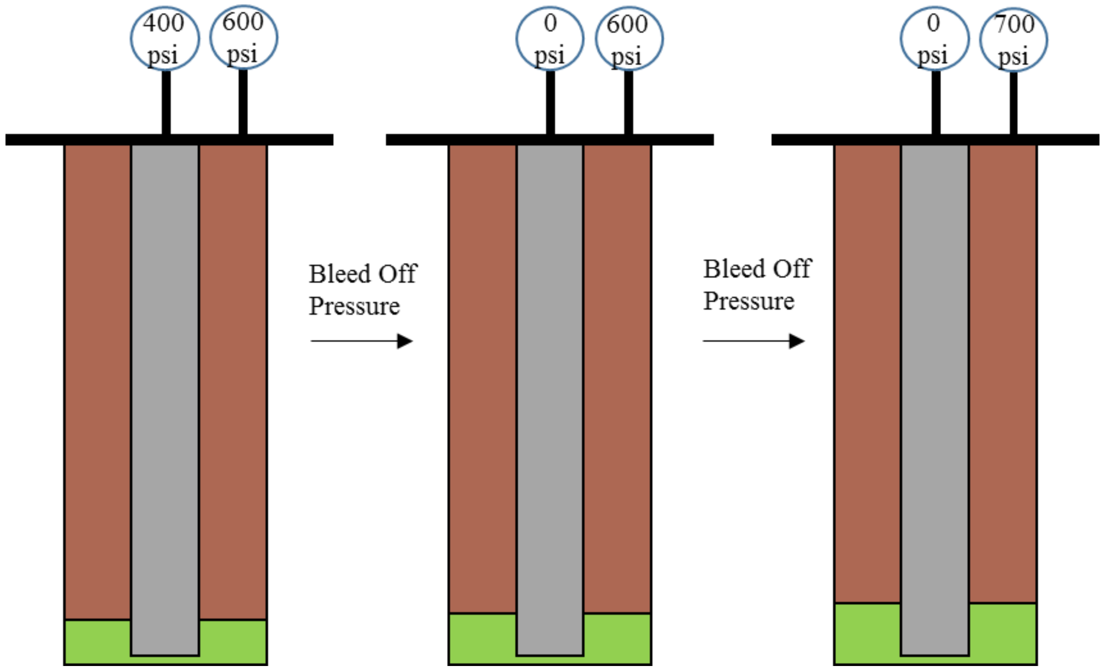

Figure 4.9: SIDPP and SICP behavior for swabbed influx scenario ($P_m > P_p$).

Figure 4.9 depicts a well that has been shut-in due to a pit-gain caused by a swabbed influx. On the left side, the well has just been shut in with a SIDPP of 400 psi and a SICPP of 600 psi. Pressure is then bled off to check for trapped pressure in the time between the left and middle graphics. This results in a SIDPP reduction to zero, indicating trapped pressure was present and that the well is not in an underbalanced state. The SICP remained the same at 600 psi in this example, but could go also go up depending on how much formation fluid was in the annulus and the compressibility of this fluid. Pressure is then bled off again in the time between the middle and right graphics to check for more trapped pressure. The SICP increases indicating that there is no more trapped pressure present and that a formation fluid is in the annulus and has expanded as the mud was bled off at surface. The next step in this case would be to circulate the annular volume out of the well and over the choke to remove the influx from the well. This would be done using the same mud weight already in the well because the SIDPP indicates that the well is in overbalance. Once the entire annular volume has been circulated out, the well would be shut in again to check pressures. Some trapped pressure may need to be bled off, but once this is done both SIDPP and SICP would be zero as the well would be overbalanced. The BOP could then be opened up and drilling ahead continued. In this case, because a kick was swabbed in, it would be beneficial to do a look-back in order to identify the cause of the swab pressure and avoid recurrence.

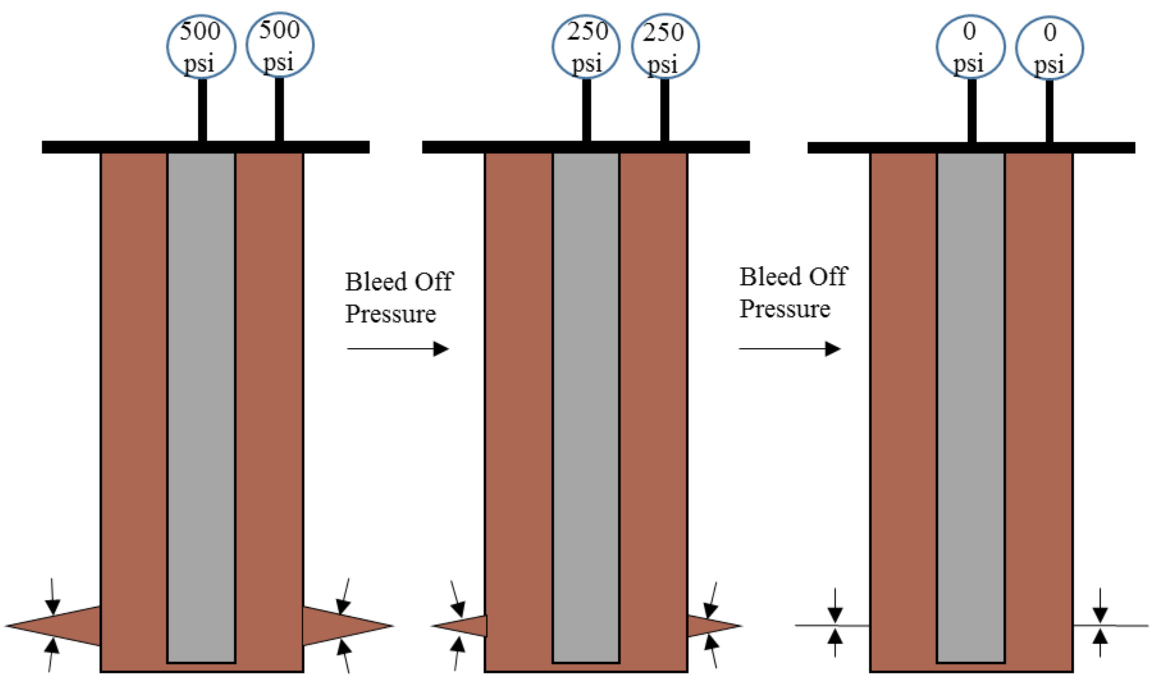

Figure 4.10: SIDPP and SICP behavior for a wellbore breathing scenario ($P_m > P_p$).

Figure 4.10 depicts a well that has been shut-in due to a pit-gain caused by wellbore breathing. On the left side, the well has just been shut in with a SIDPP of 500 psi and a SICPP of 500 psi. Pressure is then bled off to check for trapped pressure in the time between the left and middle graphics. The SIDPP is reduced to 250 psi through bleed off indicating that trapped pressure was present. In this case, the reduction in pressure is due to the fractures closing somewhat. The implicit assumption here, is that the rock behaves in a linear elastic manner: When fluid flows out of the fracture, the rock becomes less deformed, and therefore applies a lower stress (or pressure) at the fracture interface between the rock and drilling fluid. The SICP is also reduced to 250 psi during bleed off. Pressure bleed off is then continued in the time between the middle and right graphics. The SIDPP is reduced to zero indicating that the well is not underbalanced. The SICP is also reduced to zero. This indicates that the annular fluid column is also of sufficient density to balance downhole pressures, suggesting the column is composed completely of mud and no formation fluid entered the wellbore. In this scenario, losses should have also been recorded during drilling prior to shut-in and this can be used as another means to verify that wellbore breathing is occurring.

At this point, the well is static so drilling ahead could continue. However, since there was a pit gain at surface, the well would often be circulated bottoms up as a safety precaution to confirm that no influx occurred. Regardless of which approach was taken, some fluid losses would occur while circulating and another pit gain would occur whenever the pumps were shut off. If the losses were noticed while circulating, the following gain would be further evidence indicating wellbore breathing was taking place. The well may also be shut in again when the pit gain occurs. In this case, a similar bleed off process to the one described in the last paragraph would be observed indicating that wellbore breathing is occurring. Going forward, the mud weight or flow rate could be lowered, if possible, or the wellbore breathing connections flow backs could be fingerprinted similar to the process described in section 4.1.1.

In the case where hydrocarbon swap out occurred coupled with wellbore breathing, interpretation of shut-in pressures could prove to be more difficult. In this instance, an iterative approach would be required to identify the wellbore breathing coupled with hydrocarbon swap out mechanism. The shut-in pressure behavior during bleed off would be similar to the swabbed kick scenario shown in Figure 4.9, but the shut-in pressures after circulation of the influx out of the well would not be zero. In this case, another influx would enter the well via the hydrocarbon swap out mechanism when the pumps are shut off and the shut-in pressure behavior during bleed off similar to that shown in Figure 4.9 would occur again. Therefore, repetitive shut-in pressure bleed off scenarios where the SIDPP pressure is reduced to zero and the SICP is non zero, would indicate that wellbore breathing coupled with hydrocarbon swap out is occurring. A reduction in mud weight could then be used to verify if this is indeed the mechanism responsible; a reduced mud weight should lessen or eliminate the wellbore breathing and hydrocarbon swap out mechanism.

It is important to note that the three step diagrams used in this section are simplified for ease of presentation in this format. The process of bleeding off shut-in pressures at surface is a slow methodical process. It involves letting small fluid volumes out of the well and then monitoring the pressure build up once the flow is stopped. If the SIDPP pressure decreases and does not rise back to its previous value, the process is repeated. In the case of a breathing wellbore as depicted in Figure 4.10, all the drilling fluid in the fracture would need to flow back into the wellbore during the bleed off process. When each bleed off sequence only allows a barrel or two out of the wellbore, the process will take a significant amount of time. Also, if only a barrel or two of fluid is flowing out of the fracture in each of these sequences, the reduction in pressure associated with the fracture closing would be relatively small and therefore difficult to notice in surface pressures. This is a possible explanation for some of the difficulty in differentiating between wellbore breathing and kicks when shut in.

4.1.5.2 Pressure Bleed Off Volumes

The volumes required to bleed off trapped pressure after shutting in the well can be key in differentiating between wellbore breathing and a kick. These volumes are typically expressed in terms of the volume of mud flowed from the well in order to cause a 100 psi drop in the shut-in pressure or (bbl/100 psi). Field experience has shown that the bleed off volumes for wells experiencing wellbore breathing are significantly larger than the compressibility data from up-hole LOT's would suggest: Ashley (2000) experienced bleed off volumes of 10 (bbl/100 psi) in comparison to the expected 0.5 (bbl/100 psi) and Lage et al. (2002) experienced bleed off volumes of 3.25 (bbl/100 psi) in comparison to the expected 0.4125 (bbl/100 psi).

This significant difference between bleed back volumes is due to the increased size of the system that is being decompressed in a breathing wellbore. In a conventional well control situation, the system that would be decompressed in the bleed off process includes the fluid in the wellbore, the casing strings and cement behind them, and the formation itself in the open hole-section. Whereas in the case of wellbore breathing, the system includes the fluid in the wellbore, the casing strings and cement behind them, the formation itself in the open hole-section, the fluid that is in the fractures, and the portion of the formation which has been compressed due to the aperture of the fracture.

4.1.5.3 Connection Gas and Mud Weight Correlation

During drilling, increased connection gas is associated with the static wellbore pressure being at or below the formation pore pressure, which allows some formation fluids to enter the wellbore (Alberty and Fink, 2014). The appropriate response is to raise the mud weight because this would place the well back into overbalance at connections when pumps are off. Once the mud weight has been increased, inflow from the formation during connections should stop and therefore the associated connection gas reduced. If however, the connection gas continues unabated or increases with increased mud weight, this should be a “red flag” that wellbore breathing is taking place.

There are two mechanisms, when coupled with wellbore breathing, which exhibit these characteristics: hydrocarbon swap-out and gas diffusion into the drilling fluid while in the fractures. Hydrocarbon swap-out can occur with WBM, OBM, or SBM and has no temperature or pressure constraints. Gas diffusion on the other hand, will occur only when drilling with an OBM or SBM system and is more likely to occur in high pressure and high temperature (HPHT) conditions. In a WBM, gas diffusion will not occur quickly enough to cause connection gas as gas solubility in water is very small (Bradley et al., 2002). Along the same lines, gas diffusion related connection gas can be significant in HPHT wells drilled with OBM or SBM systems because methane is infinitely soluble in these conditions and substantial amounts of gas can be dissolved into the mud (Bradley et al., 2002). Regardless of which of these specific mechanisms is coupled with wellbore breathing, the appropriate response is to reduce the mud weight because this will reduce the wellbore breathing effect. A reduction in the wellbore breathing effect will reduce the amount of fluid in the fracture system and therefore reduce the effects of either hydrocarbon swap-out or gas diffusion, whichever is occurring.

4.1.5.4 PWD Measurements

The best solution to reduce the effects of wellbore breathing, a reduction in mud weight, is often not possible due to high pore pressures. In these cases, drilling ahead is continued with the current mud weight, resulting in losses while drilling and large pit gains at connections. These large pit gains, anywhere from 25 to 350 barrels (Tare, Whitfill, and Mody, 2001), can easily mask a kick occurring during a connection. However, a PWD tool could be used to detect these kicks by monitoring for any changes in circulating density.

Once pumps are started up after a connection, the ECD measured by the PWD tool can be used to infer whether an influx has taken place as long as circulating conditions are the same as before the connection. In this case, the ECD returning and stabilizing at the same pre-connection value would indicate that no influx has occurred. However, if the ECD were to stabilize at some value lower than the pre-connection ECD, this would indicate an influx has occurred. This behavior is due to the fluid density in the annulus. If a formation fluid influx were to occur during a connection, the density of the fluid column would be lessened. If the fluid gain at the connection was mud flowing back into the well, as occurs during wellbore breathing, the density of the fluid column would be unchanged.

4.2 Mitigation of Wellbore Breathing

This section focuses on methods for mitigation of wellbore breathing and its effects while drilling. These approaches typically fall into two categories: (1) limitation of the pressure fluctuations which cause fracture opening and closing or (2) mechanical limitation or elimination of the underlying fracture opening and closing mechanism itself.

4.2.1 ECD Management

ECD management involves limiting the fluctuation between downhole pressures during static conditions and during circulating conditions as well as the rate at which those fluctuation occur. ECD management pertains primarily to operating procedures which can be changed in real-time, but also includes changes in the well plan both while drilling and pre-spud, if wellbore breathing is expected. A large driver of ECD is frictional losses in the annulus so reduction in these frictional effects are a key aspect of ECD management. These frictional losses are a function of fluid velocity, fluid density, and the flow area as shown by Mitchell and Miska (2011):

$$\Delta P_{friction} = \frac{2\, f \rho v^2}{d_{ann.} - d_{dp}} \tag{4.4}$$

Where,

f = Fanning friction factor

d_{ann} = Diameter of annulus

d_{dp} = Outer diameter of drill pipe

v = Fluid velocity

ρ = Fluid density

First, limiting the fluid velocity in the annulus will reduce frictional losses and can be achieved by using reduced circulating rates. There are however limiting factors pertaining to the magnitude of circulating rate reductions. Circulating rates need to be maintained at a high enough rate to adequately clean the hole and move drill cuttings up the annulus. Further, circulation rates also need to be maintained at a high enough level to adequately cool the bit while drilling. Inadequate cooling of the bit can result in early bit failure, which could prove costly over the course of a well due to both bit costs and associated NPT. Last, circulating rates must be maintained at a high enough level to enable downhole tools to transmit data to surface using mud pulse telemetry or they will be effectively drilling blind.

Second, increasing the diameter of the annulus will increase its cross sectional area and decrease frictional losses. Additionally, an increased annular cross section will decrease the annular fluid velocity for a given flow rate, and therefore decrease frictional losses. An increased flow area can be achieved during the pre-spud stage if breathing is expected by designing the well with larger hole sizes and larger casing diameters. However, increasing casing diameters can significantly increase the well cost and wellbore breathing is often not expected until encountered while drilling. In real-time, once wellbore breathing is encountered, the bit diameter size that can be used for a given hole-section is limited by the diameter of the casing string set up-hole. However, a hydraulically activated reamer could be run in the BHA above the bit, enabling a larger hole size to be drilled below the limiting casing string. Hydraulically activated reamers consist of sets of rock cutting blades and cutters similar to those found on the bit, which extend out from the BHA once a certain flow rate has been exceeded. These extended blades cut away at the wellbore wall to create a larger hole-section than the bit diameter alone could create.

In addition to altering the magnitude of the pressure fluctuations caused by ECD, the rate at which those fluctuations occur can also be reduced. This can be done by staging pump start up and shut down over a period of time, rather than bringing pumps to and from circulating rates instantaneously. In this case, the fluid gains and losses at surface would be more gradual. This is beneficial because it makes the gains easier to monitor at surface and also dilutes the fluid exiting the fracture downhole. Dilution of this outflow is advantageous because of the potential for hydrocarbons to be present in this flow. With a staged pump shut down, these hydrocarbons would reach surface over a long period of time rather than all at once.

Another method for ECD management is minimizing the increased fluid density during drilling caused by cuttings suspended in the fluid. This can be accomplished by control drilling to keep the rate of penetration below a designated threshold. This will decrease the amount of drill cuttings in the annulus at a given time and therefore reduce the density of the fluid column. Another potential approach would be to pause periodically while drilling and circulate fluid to remove some of the cuttings laden drilling mud from the annulus. This could be accomplished by circulating for periods before and after connections and would work hand in hand with the staged pump start up and shut down procedure mentioned earlier in this section. Both management of ROP and circulation for periods around connections will increase the total drilling time for a section, increasing costs.

4.2.2 Fracture Bridging/Plugging

While typically discussed as a response to severe lost circulation events, the underlying fracture mechanism is similar and can be mitigated using similar approaches. As it pertains to wellbore breathing, the goal is to isolate the fracture from the wellbore so that fluid cannot flow into and out of the fracture or propagate the fracture. Some of the typical products and techniques used include adding fibrous, flaky, or granular lost circulation material (LCM) to the drilling fluid, placement of a cross-linked polymer and fibrous material blend across the loss zone, and in extreme cases pumping a cement plug into the wellbore in the area where losses are occurring.

An advantage to the approach of adding LCM to the drilling fluid is that the LCM will contact the entire annulus. It can therefore be successful in the plugging of fractures without exact identification of the loss zone. However, shear degradation of the LCM particles during circulation and removal of the LCM particles from the mud by the solids control equipment can limit the effectiveness of this approach (van Oort et al., 2009).

An advantage to using the cross-linked polymer mixture is the speed with which it can be applied. The polymer and fibrous material can be pre-mixed and stored at surface so that only the cross-linker needs to be added and it can be pumped downhole after 5 minutes of mixing (Caughron et al., 2002). This is useful because it could be applied whenever wellbore breathing is first identified and therefore limit the extent to which the fracture is propagated. In the case of wellbore breathing, it would likely be necessary to bullhead the cross linked mixture into the fractures because fluid is not flowing into the fractures at static conditions, like in a lost circulation situation. Bullheading is the process of shutting in the well and pumping fluid down the drill pipe to force fluid, or bullhead, into the formation. The primary disadvantage with the cross-linked polymer mixture is that it is a spot treatment. Therefore, the exact zone where wellbore breathing is occurring needs to be properly identified to enable a successful treatment.

In extreme wellbore breathing and lost circulation cases where one or both of the aforementioned approaches fail, a cement plug can be pumped into the fractured zone and allowed to set. The cement will penetrate into the fractures filling and sealing off the system and once set, the plug left in the wellbore is drilled out (Low, Daccord, and Bedel, 2003). While pumping cement can be an effective approach to eliminate wellbore breathing, it can be very expensive due to the volume of cement required to pump as well as the rig time spent waiting on the cement to set. Additionally, care must be taken when drilling through the cement plug. If the cement is harder than the formation itself, this can lead to inadvertently side tracking the well and exposing the wellbore to the same wellbore breathing or loss zone.

4.3 Prevention of Wellbore Breathing

There are typically two lines of approach for the prevention of wellbore breathing: prevention of the initiation of fractures and elimination of the ECD induced pressure fluctuations between circulating and static conditions. The former focuses on managing downhole pressures and temperatures to maintain wellbore integrity while the latter focuses on the development and implementation of specialized equipment at surface.

4.3.1 Accurate Kill Mud Weight Calculations

Often times, kill mud weights are calculated in a conservative manner to ensure overbalance, which subjects the wellbore to unnecessarily high pressures. These unnecessary pressures can exceed the fracture gradient and result in fracture initiation. Furthermore, initiation of these fractures can lead to wellbore breathing occurring directly after a well control event. As shown by the earlier case study from offshore Brazil (Lage et al., 2002), a wellbore breathing event directly following a well control incident can mask the wellbore breathing mechanism and make identification difficult. Also, since kicks often take place in hydrocarbon bearing zones, wellbore breathing in these situations may be coupled with hydrocarbon swap-out or gas diffusion. This can make identification more difficult and cause safety issues due to hydrocarbon returns at surface.

The accuracy of kill mud weight calculations is directly related to the accuracy of the SIDPP in its measurement of the BHP. In order to achieve an accurate BHP measurement via the SIDPP, all trapped pressure must be bled off and the float valve within the drill string must be open. Details regarding pressure bleed off procedures have already been detailed in 2.6.11 so they will not be repeated here, but issues with attaining SIDPP due to float valves have not yet been discussed. Float valves are typically run in drill strings as a means to prevent formation fluids from travelling up the drill string during well control events. While preventing flow up the drill string is necessary, closure of the float valve in these situations prevents pressure communication from below the valve and prevents measurement of the BHP via the SIDPP. Bradley (1987) detailed a procedure for attaining the SIDPP with a closed float valve in the drill string:

- Once well has been shut in, record the SICP.
- Start pumps and maintain the pump rate at the pump rate used during the last recording of the slow circulating rate pressures.
- Once pumping has begun, use the choke to maintain the SICP at the pressure recorded in the first step.
- Record the stand pipe pressure with the correct pump rate and casing pressures specified above being maintained.
- Shut down the pumps and close the choke so the well is shut in again.
- Subtract the earlier slow circulating rate pressure from the stand pipe pressure recorded while pumping and this value is the SIDPP that should be used for calculation of the kill mud weight.

The expected pressure response during this procedure as well as explanations for their occurrence are displayed below in Figure 4.11.

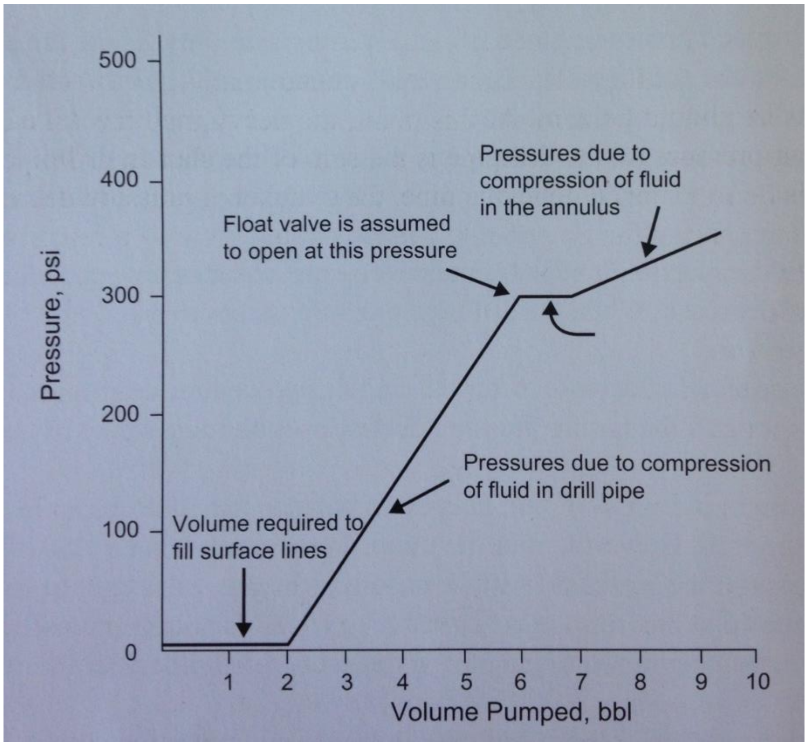

Figure 4.11: Procedure to attain SIDPP with a float valve in drill string (Bradley, 1987).

4.3.2 Drilling Fluid Temperature Management

Fluid temperatures, as detailed in 4.2.4.1, can induce thermal stress changes in downhole formations resulting in a reduction in the effective fracture gradient if the formation is cooled sufficiently. Because of this, fluid system temperatures should be managed to ensure that thermal stress changes are not allowed to decrease the effective fracture gradient to the point where fractures are induced. In order to do this, accurate temperature measurements of the mud within the pit system is necessary as well as real-time downhole temperature measurements using MWD.

Using downhole temperature measurements, a minimum threshold can be set for the downhole temperature. Since the bottom hole temperature decreases during circulation and increases during static periods (Karstad, 1998), this may require periodic pauses in drilling to allow the formation to warm whenever the minimum temperature threshold is approached. Additional care must be taken in artic or cold weather environments where temperatures are low and can cause significant drilling fluid temperature reductions at surface. In these situations, the pit system at surface should be insulated or a heat exchanger used to keep the drilling fluid warmed.

An additional point of emphasis should be placed on kill mud temperatures prior to circulating the mud into the well during well control situations. Regardless of whether the Driller's Method or Wait-and Weight Method is used, mud from the active pit system should be weighted up to the specified kill mud weight rather than using mud from outside the active pit system. The mud within the active system will be at a higher temperature because it has been continuously circulated downhole and warmed by the earth's thermal gradient. Using colder mud from the inactive pit system will create an unnecessary reduction in the effective fracture gradient.

Last, a heat exchanger could be incorporated at surface to warm the drilling fluids. This would maximize the drilling window on a given well by minimizing reductions in the formation's effective fracture gradient due to thermal effects. Incorporation of the heat exchanger would likely incur significant costs due to the needed rig modifications, but would could be cost competitive in situations where the downhole temperatures were being actively managed; pausing drilling activities to allow the downhole formation to warm would prove timely and likely cost prohibitive due to the high price of rig day rates. One limitation to this approach would be use with OBM's as maintaining these muds at higher temperatures would result in gases being released at surface.

4.3.3 Managed Pressure Drilling

Managed pressure drilling (MPD) is a suitable system for prevention of wellbore breathing because it maintains a constant bottom hole pressure throughout the drilling process. This eliminates the pressure fluctuation between circulating and static conditions, which drive the wellbore breathing phenomenon. Maintaining a constant bottom hole pressure allows wells with extremely small mud weight windows to be drilled, which would be either impossible or very costly to drill conventionally. Furthermore, since the downhole pressure is maintained by backpressure at surface in addition to the fluid column, changes can be made instantaneously by adjusting the backpressure applied at surface. This is extremely useful in response to events such as lost circulation or a kick. The primary limitations to MPD implementation are the initial cost and time required to install the system, as well as some drilling engineer's and operations staff's unfamiliarity with the system. However, Saponja, Adeleye, and Hucik (2006) suggest that the system's advantages far outweigh the additional up front cost and can actually save money due to reductions in NPT and increased ROP due to less overbalance while drilling.

4.3.4 Continuous Circulation System

Continuous circulation systems aim to maintain a constant bottom hole pressure by maintaining ECD throughout the drilling process. This will effectively eliminate wellbore breathing as there will no longer be downhole pressure fluctuations due to shutting pumps off. However, the continuous circulation system does require installation of a secondary flow line on the rig floor and operational procedures at connections must be altered to allow connection of this flow line to the side port sub in the drill string prior to disconnecting the top drive. Additionally, reliance on ECD to maintain overbalance can result in influxes if pump failure is experienced and annular pressures decrease. A distinct advantage of the constant circulation system would be constant availability of downhole data via mud pulse telemetry since the pumps are not shut-off.

Chapter 5: Estimation of Minimum Horizontal Stress

5.1 Hydraulic Fracturing Background and Theory

This section details the theoretical background for using downhole pressure measurements to obtain the fracture closure and estimate the minimum horizontal stress using pump-in flowback tests. It details the original work focused on aqueous fluids, subsequent works verifying applicability to pump-in flowback tests with drilling fluid, and then discusses the applicability to PWD measurements during wellbore breathing incidents.

5.1.1 Pump-in Flowback Tests in Hydraulic Fracturing

Pump-in flow back tests consist of initiation or reopening of a fracture by pumping fluid downhole and then flowing this fluid back out of the fracture to force fracture closure. Pressures are recorded throughout the test and can be used to determine the fracture closure pressure, indicating the minimum horizontal stress, which is useful for fracture treatment design and evaluation (Plahn, Nolte, and Miska, 1997).

Plahn, Nolte, and Miska (1997) used a numerical model, validated over a broad range of test cases, composed of a wellbore and a single propagating/closing fracture within a reservoir to model pump-in flowback tests in order to better understand the physical mechanisms behind the pressure response seen during tests in the field. Their model assumed a slightly compressible Newtonian fluid was being injected, all simulated pressures were BHP’s, and the fracture deformation and geometries were described using two different models: plane strain in the vertical direction (Perkins and Kern, 1969) and plane strain in the horizontal direction (Nordgren, 1972). Their work resulted in a multitude of useful findings pertaining to hydraulic fracturing stimulation, but of interest for this work, was the determination of the correct method for picking the closure pressure from the pressure response during tests. Plahn, Nolte, and Miska (1997) explained that the methodology for picking the fracture closure pressure involves drawing lines through the linear trends seen early in the flowback and late in the flowback with the intersection of these lines providing a close estimate of the minimum horizontal stress (zero wellbore net pressure is the minimum horizontal stress). This methodology is shown for differing flowback rates in Figure 5.1

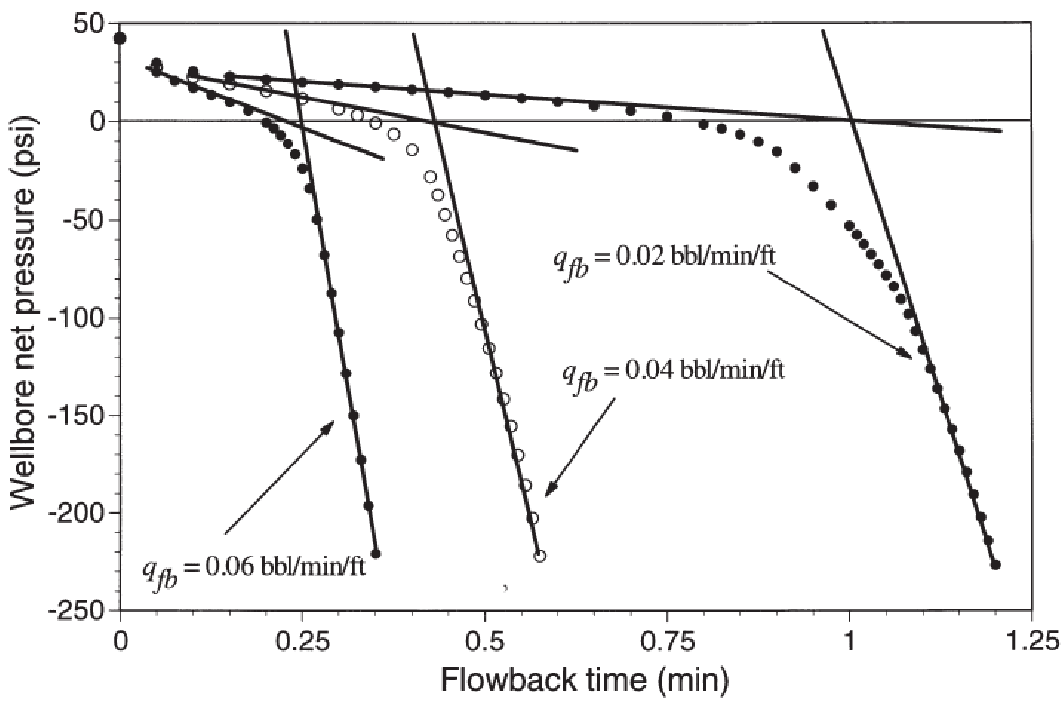

Figure 5.1: Simulation results for flowback portion of pump-in flowback tests (Plahn, Nolte, and Miska, 1997)

5.1.2 Pump-in Flowback Tests in Drilling Operations

Pump-in Flowback tests are also employed during drilling operations in order to estimate the minimum horizontal stress at the casing shoe prior to drilling ahead, although LOT's are far more common. However, the drilling fluids used to perform these tests are typically non-aqueous and laden with solid material such as barite, which differs significantly from the slightly compressible Newtonian fluid used in the Plahn, Nolte, and Miska (1997) model. Additionally, the pressures simulated in the Plahn, Nolte, and Miska (1997) model were all downhole pressures, whereas pressures are typically recorded at surface for pump-in flowback tests performed during drilling operations.

Raaen et al., (2001) used an analytical model composed of a fluid filled well, an ellipsoidal vertical fracture, fluid leak off into the formation, and fluid flowback at surface to describe the pump-in flowback test. Raaen et al. described the model behavior in terms of the system stiffness:

$$S = \frac{dp}{dV} \tag{5.1}$$

Where,

S = system stiffness

p = pressure

V = volume

And the two primary contributors to system stiffness are:

- Hydrostatic compression/decompression of fluid volume in well (well stiffness)
- The elasticity of the fracture (fracture stiffness)

The fracture closure was considered to be a two stage closure as described by Hayashi and Haimson (1991) in which the fracture initially closes in a “hinge like” manner followed by closure at the fracture tip as displayed in Figure 5.2.

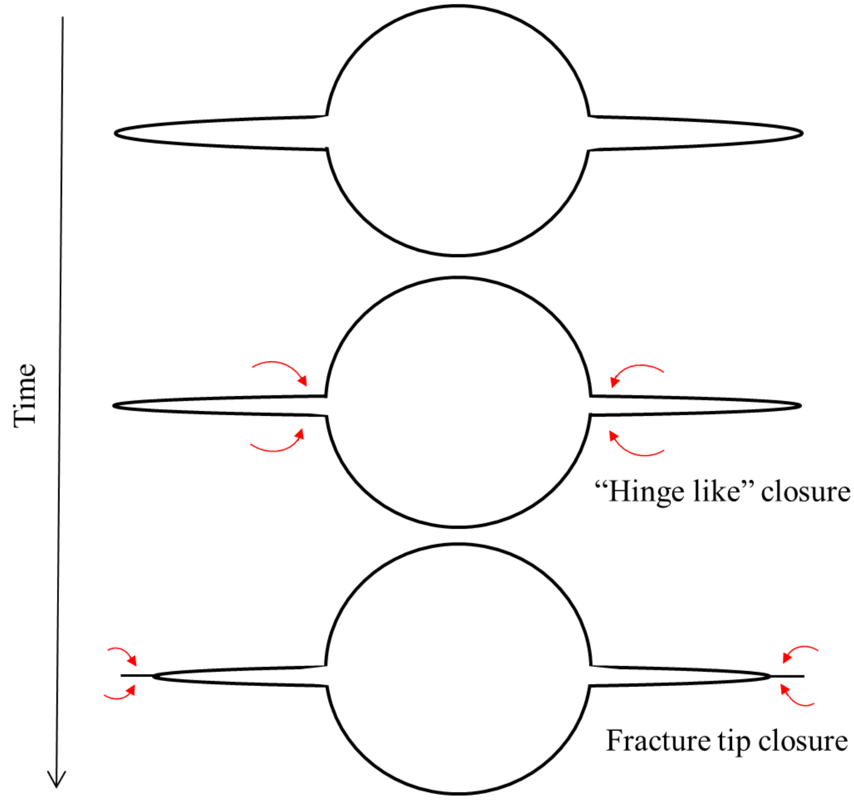

Figure 5.2: Fracture closure process

Raaen et al. (2001) proposed that during a pump-in flowback test, the system stiffness would initially be constant as it composed both the fracture stiffness and well stiffness, followed by a transitionary period as the fracture initially closes at the tip and then approaches full closure, and ending with the constant well stiffness as the fracture has completely closed. Raaen et al. (2001) proposed that the initial deviation from constant slope, when the fracture tip closes, indicates the minimum horizontal stress. Using this simple model, Raaen et al. (2001) were able to interpret pump-in flowback tests from two different field tests which showed good qualitative agreement over several tests and with the authors' understanding of stresses in the area. A plot of pressure versus volume, the system stiffness, from one of the field tests is shown below in Figure 5.3 with an interpretation of 75 MPA as the minimum horizontal stress. A plot of pressure versus time can also be used and yielded similar results in the work by Raaen et al. (2001).

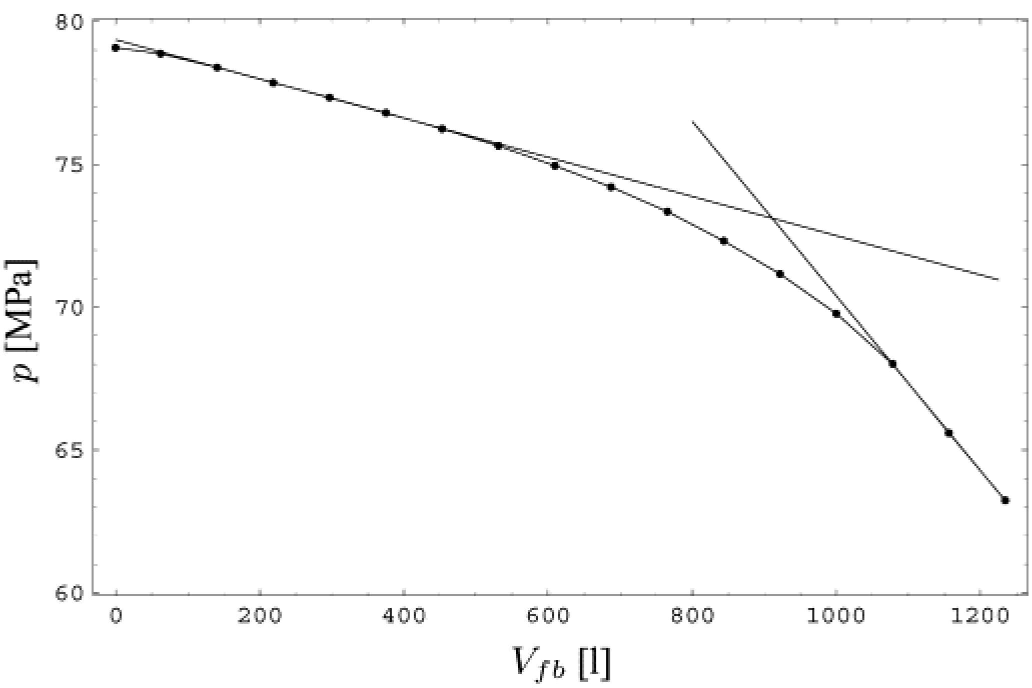

Figure 5.3: Pump-in Flowback test data from North Sea well (Raaen et al. 2001).

Additional work by Gederaas and Raaen (2009) confirmed the system stiffness approach for determination of the minimum horizontal stress through three additional field tests using OBM in impermeable formations at casing shoes. Gederaas and Raaen (2009) also proposed using a square root of pressure versus time plot rather than the volume versus time plot, because flowback volume data tends to be noisy, and showed that its results were in agreement. The square root of pressure relationship arises because the flow rate through the choke during flowback is proportional to the square root of the pressure drop across the choke.

While Raaen et al. (2001) and Gederaas and Raaen (2009) demonstrated the ability of pump-in flowback tests with drilling mud to estimate the minimum horizontal stress, the simplistic model used to interpret the tests provides a qualitative estimate of the minimum horizontal stress rather than a quantitative. Raaen et al. (2001) acknowledged that the fracture closure process is very complex, stated that the minimum horizontal stress within the fracture closure transition period is difficult to distinguish, and states that authors' interpretation of the closure process indicates the minimum horizontal stress is associated with the deviation from the initial linear stiffness slope. This interpretation of pump-in flowback tests was originally proposed by Nolte and Smith (1981) using a similar simplistic analytical model to describe the fracture behavior. However, as shown in 5.1.1, later work by Plahn, Nolte, and Miska (1997) showed that this interpretation was actually incorrect and resulted in an overestimation of the minimum horizontal stress.

5.1.3 Pump-in Flowback Test Applicability to Wellbore Breathing

The downhole process which occurs during wellbore breathing events is very similar to a pump-in flowback test and should enable interpretation of PWD measurements during breathing events in a similar manner. The similarities between wellbore breathing and a pump-in flowback test include:

- Increased wellbore pressure forces fracture opening and forces fluid into the fracture causing propagation.

- Wellbore pressure then decreases, allowing fractures to close and forcing fluid back into the wellbore.

The dissimilarities between wellbore breathing and a pump-in flowback test include:

- There is an uncontrolled flowback rate during wellbore breathing events while pump-in flowback tests typically incorporate a constant flowback rate or use a choke to restrict flowback at surface.
- Wellbore breathing often takes place within a large open hole-section while pump-in flowback tests are typically performed in a confined hole-section or short rat hole below a casing shoe.
- Pump-in flowback tests start with a pressure below the minimum horizontal stress, create and propagate a fracture, and then end with a pressure below the minimum horizontal stress. In wellbore breathing this may or may not be the case.

Plahn, Nolte, and Miska (1997) showed that rate of flowback does not have an effect on the ability of their interpretation method to determine the minimum horizontal stress, but increased flowback rate does shorten the linear portions of the pressure versus time plot. Therefore, in wellbore breathing cases where the flowback rate is high and fracture closure occurs quickly, it may be difficult to identify the linear behavior required to estimate the minimum horizontal stress.

Wellbore breathing events which take place within a large open hole-section may also make interpretation difficult. This opens up the potential for multiple fractures within different formations. This scenario would make interpretation difficult, if not impossible, because the pressure responses would be occurring simultaneously and the in-situ stresses would likely be different. Additionally, the fracture in wellbore breathing may or may not be at the same depth as the PWD device recording the pressures. Because of this, the interpretation of downhole pressure measurements and expression of results should use a pressure gradient rather than actual pressure values. If the specific wellbore breathing zone can be identified via LWD tool or some other means, these gradients can easily be converted to actual pressure and stress values for that given depth.

Last, wellbore breathing can occur in circumstances where the static wellbore pressure is at or above the minimum horizontal stress. In these cases, interpretation of the PWD data would not yield an estimate for the minimum horizontal stress because fracture closure would not occur. In this case, the static wellbore pressure could be taken as the upper bound for the minimum horizontal stress.

A potential advantage of using wellbore breathing events for estimation of the minimum horizontal stress is the repetitive nature of wellbore breathing compared to pump-in flowback tests or LOT's, which are typically performed only once at the casing shoe. This repetition will provide a larger data set and reduces the risk of an incorrect estimation of the minimum horizontal stress as any outliers can be identified and excluded.

If the volume lost and gained during a breathing event is large, in the tens to hundreds of barrels, the fracture will likely reach more than several wellbore radii into the formation, depending on the fracture height. Therefore, the fracture closure pressure will be indicative of the far field minimum horizontal stress and will not be altered due to stress concentrations around the wellbore. During LOT's, the fracture is typically not propagated into the far field as this would reduce wellbore strength. Because of this, fracture closure pressures obtained using LOT, if obtained at all, may be influenced by near wellbore stress concentrations and result in an inaccurate estimate of the minimum horizontal stress.

5.1.4 Previously Proposed Methods

Use of downhole pressure measurements during wellbore breathing events for estimation of the minimum horizontal stress was first proposed by Ward and Clark (1998) and subsequently by Edwards, Bratton, and Standifird (2002). Ward and Clark (1998) proposed that the early departure of pressure from linearity with time during flowback could be interpreted as the minimum horizontal stress similar to the method in LOT's, but referenced no theoretical background for this assertion. Edwards, Bratton, and Standifird (2002) proposed using two different methods to estimate the minimum horizontal stress: (1) early departure of pressure from linearity with time during flowback could be interpreted as the minimum horizontal stress, (2) plotting the square root of pressure versus time results in the intersection of the lines drawn through the two linear portions indicating the minimum horizontal stress.

Using the early departure from linearity in a pressure versus time graph, proposed by both Ward and Clark (1998) and Edwards, Bratton, and Standifird (2002) is the same method originally proposed by Nolte and Smith (1981) for interpretation of pump-in flowback tests. However, as mentioned in section 5.1.2, later work by Plahn, Nolte, and Miska (1997) showed that this method was incorrect and overestimates the minimum horizontal stress.

The second method proposed by Edwards, Bratton, and Standifird (2002) originates from shut in tests used during hydraulic fracturing to estimate the fracture closure pressure. These shut in tests rely on fluid leakoff into the formation to allow fracture closure. While this test will not be detailed here, the square root of time relationship used to estimate the fracture closure pressure originates from Carter Leakoff theory (Howard, Fast, and Carter, 1957) which states that the flow rate of fluid leaking off into the formation is:

$$q_{leakoff} = \frac{2A_pC_L}{\sqrt{t-\tau_p}} \tag{5.2}$$

Where,

A_p = fracture surface area

τ_p = time when the fracture formed

C_L = leakoff coefficient

While this square root of time relationship is useful for shut-in test, fluid flow out of the fracture during wellbore breathing is dominated by flow back into the wellbore rather than flow into the formation via leakoff. Because of this, there will not be a square root of time relationship for wellbore breathing and the second method proposed by Edwards, Bratton, and Standifird (2002) will yield inaccurate estimates of the minimum horizontal stress.

While Ward and Clark (1998) and Edwards, Bratton, and Standifird (2002) each proposed estimating the minimum horizontal stress using PWD measurements during wellbore breathing, to the best of the author's knowledge, this is the first proposal to use the pump-in flowback interpretation proposed and verified by Plahn, Nolte, and Miska

(1997) to interpret PWD data from wellbore breathing events in order to estimate the minimum horizontal stress.

5.2 Results for Estimation of Minimum Horizontal Stress Using PWD Measurements

This section presents results for the estimation of the minimum horizontal stress using PWD data during wellbore breathing events. The methodology used to interpret the data and estimate the minimum horizontal stress is the same method originally presented by Plahn, Nolte, and Miska (1997) for pump-in flowback tests. A number of wells with published PWD data during breathing events will be presented. Estimates of the minimum horizontal stress obtained from these PWD measurements will be compared with the values obtained during LOT's as well as the pressures which initiated losses or the wellbore breathing itself. These minimum horizontal stress values will be expressed in terms of the pressure gradient, lbs/gallon (ppg), rather than an exact stress in psi as the measurements occur at different depths in the wellbore and the exact depth of the fracture is often unknown.

5.2.1 Gulf of Mexico, Well 1

Ward and Clark (1998) published a case detailing wellbore breathing incidents and included PWD measurements for three wellbore breathing events. Each of the wellbore breathing events occurred in the 8 ½" hole section at connections between 16,877 and 17,553 feet. The first connection did not exhibit a noticeable increase in flowback at surface, but the pressure decay after pump shut down indicated that breathing was occurring. The second two connections showed flowback volumes of 170 bbls and 60 bbls respectively, indicating that the fractures were likely propagated into the far field. The third connection was performed quickly and the pumps were turned back on prior to the static mud weight being reached. For reference, a LOT was performed near the casing shoe, 15,616 feet, and indicated a fracture pressure of 16.45 ppg. Also, the drilling fluid in use was an OBM. The PWD data from each of the connections is plotted below with lines drawn through the linear behavior and the intersection of these lines indicating the minimum horizontal stress.

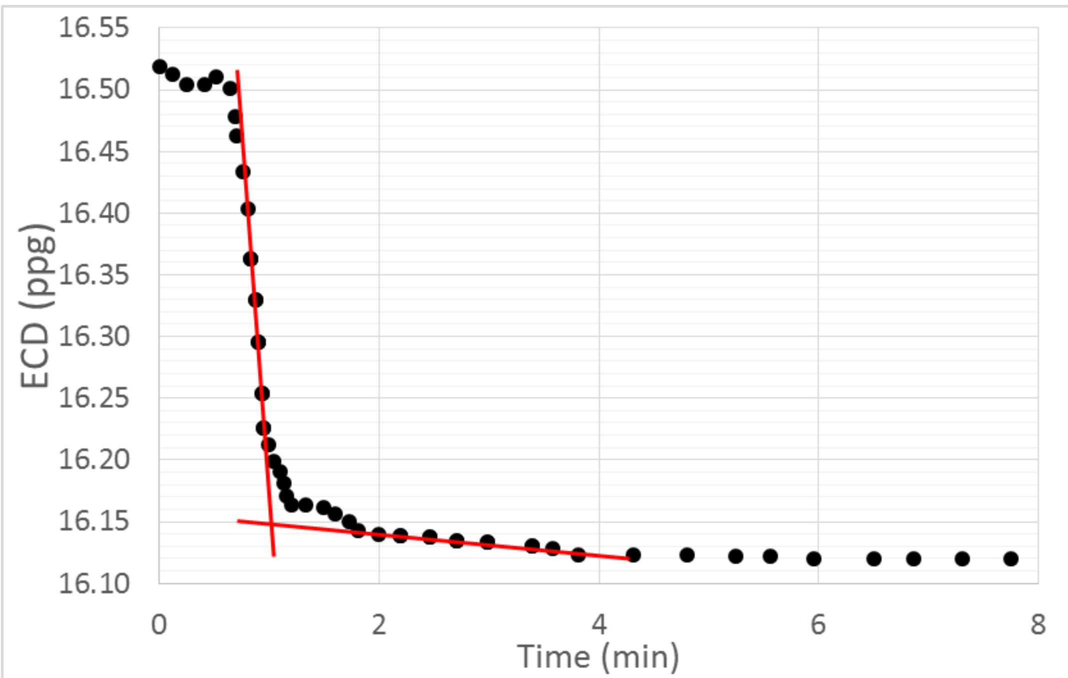

Figure 5.4: Minimum horizontal stress estimation for first connection on GOM well 1 (Data from Ward and Clark, 1998)

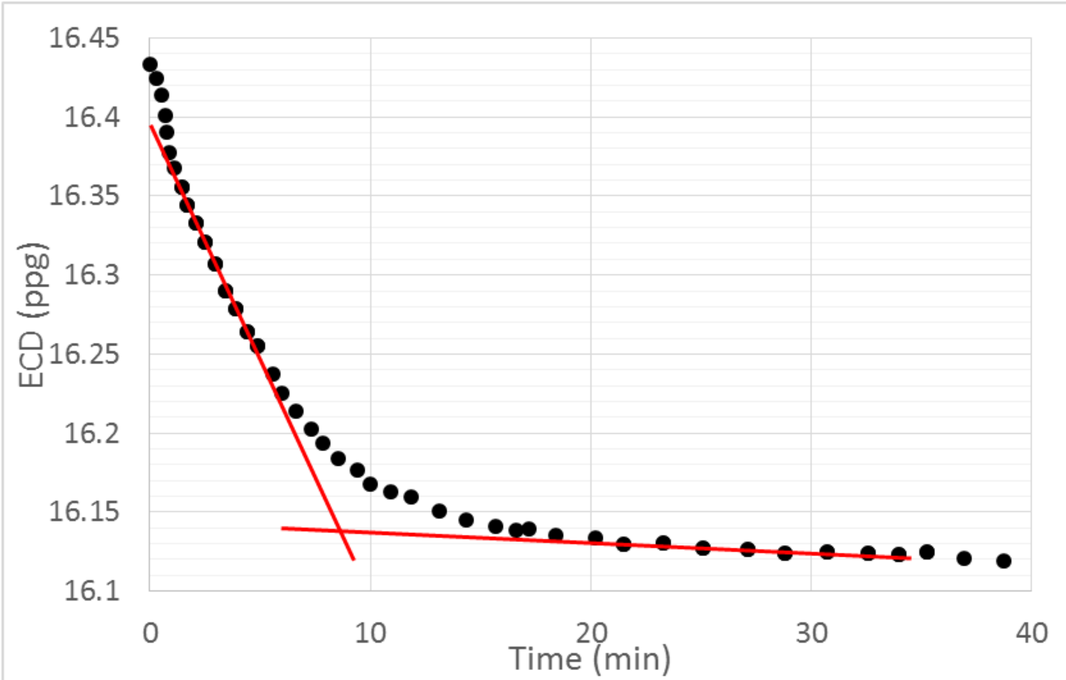

Figure 5.5: Minimum horizontal stress estimation for subsequent connection on GOM well 1 (Data from Ward and Clark, 1998)

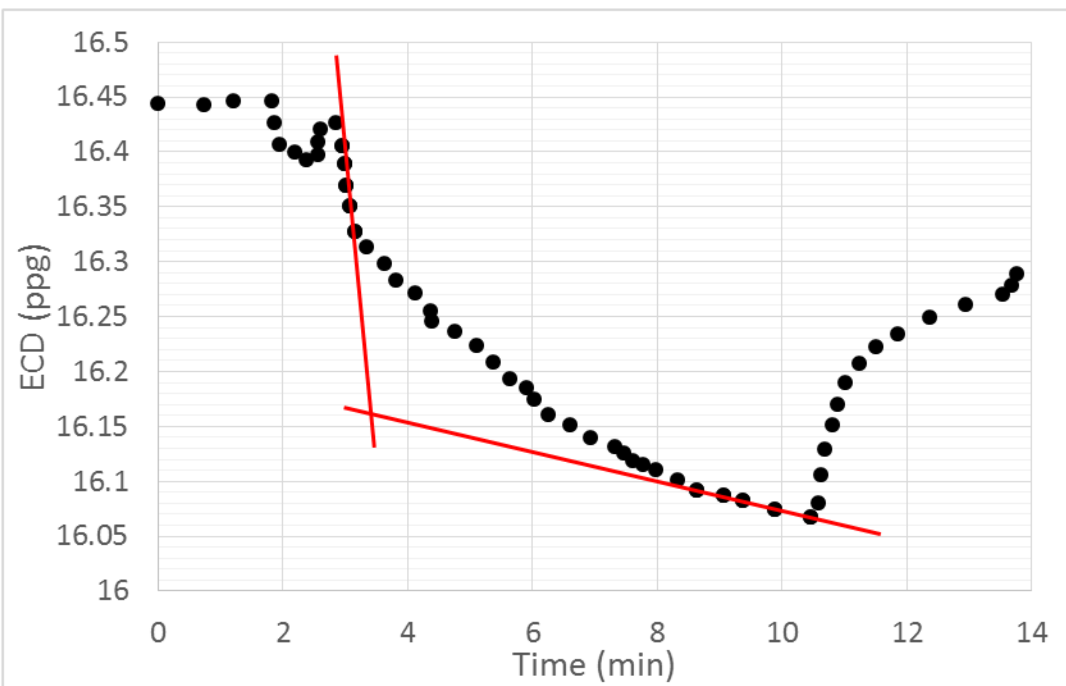

Figure 5.6: Minimum horizontal stress estimation for third connection on GOM well 1 (Data from Ward and Clark, 1998)

The PWD data from the three connections indicate a minimum horizontal stress value of 16.15, 16.14, and 16.16 ppg respectively. Care should be taken interpretation of the last connection, shown in Figure 5.6, as the pressure decline is cut short when pumps are started up. While the data just prior to pump start up does appear to exhibit a linear tend, the trend is relatively short and it is unknown if this trend would have continued. However, the fact that the analysis yielded a similar result to the other two connections is encouraging. These estimates show that the LOT pressure recorded was significantly larger than the pressure required to induce losses. Ward and Clark (1998) stated that the mud weight was later decreased, resulting in ECD's of 16.23-16.28 ppg, which reduced but did not eliminate flowback from wellbore breathing. This indicates that the minimum horizontal stress was below these ECD's, which is consistent with the values estimated in this analysis.

5.2.2 Gulf of Mexico, Well 2

Edwards, Bratton, and Standifird (1998) published a case detailing wellbore breathing incidents and included PWD measurements for wellbore breathing events in two different wells. The first of these two wells will be examined here. The wellbore breathing events occurred in the 8 ½" hole section and PWD data for one is included in the paper. Over 50 barrels of drilling fluid was flowed back at this connection, indicating the fracture was likely propagated into the far field and should provide an accurate estimate of the minimum horizontal stress. . The pressure data from the connection is plotted in Figure 5.7 below. The data exhibits a distinct linear trend early in the flowback, while the linear trend in later part of flowback is more difficult to identify. The minimum horizontal stress is estimated as 16.87 ppg, but it is difficult to gauge the accuracy of this without more data.

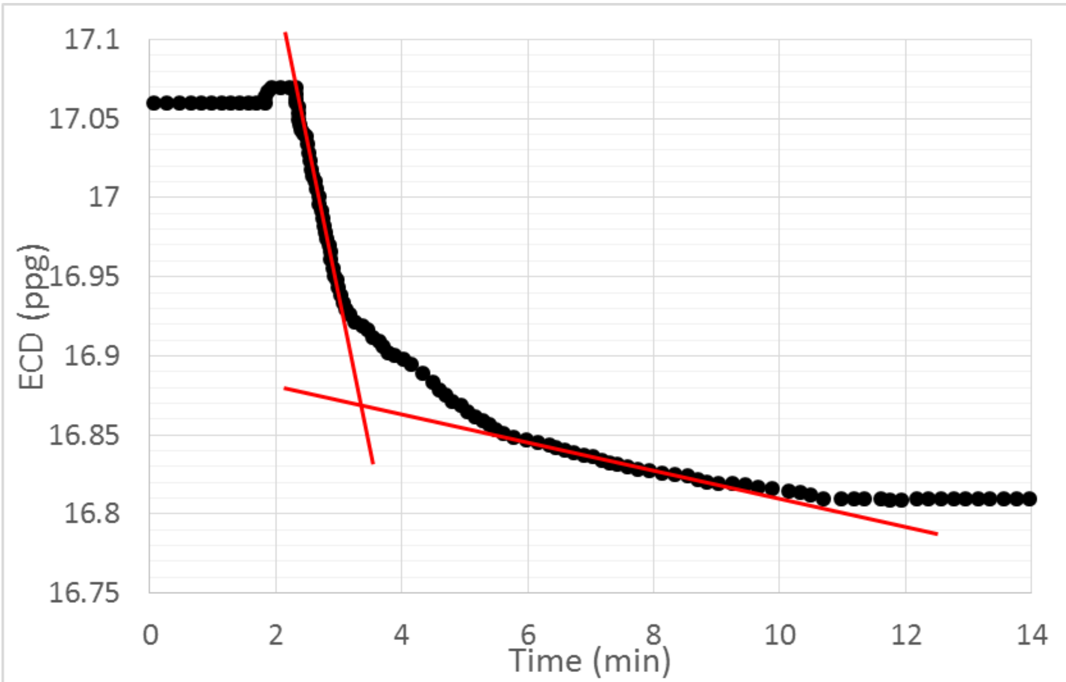

Figure 5.7: Minimum horizontal stress estimation for connection on GOM well 2 (Data from Edwards, Bratton, and Standifird, 1998)

5.2.3 Gulf of Mexico, Well 3

The second well Edwards, Bratton, and Standifird (1998) included in their paper is included here. LWD data presented in the paper shows that the fracture responsible for this wellbore breathing event was in a sandstone bounded by shale intervals. The fracture height was roughly 75 feet. . The pressure data from the connection is plotted in Figure 5.7 below. The data exhibits a distinct linear trend early in the flowback, while the linear trend in later part of flowback is more difficult to identify. This is likely due to the pumps being turned back on at the 8 minute mark, which would have stopped fluid flow out of the fracture. The minimum horizontal stress is estimated as 12.93 ppg, but it is difficult to gauge the accuracy of this without more data concerning the well. More connection data with breathing would be useful to compare the estimated minimum horizontal stress from each.

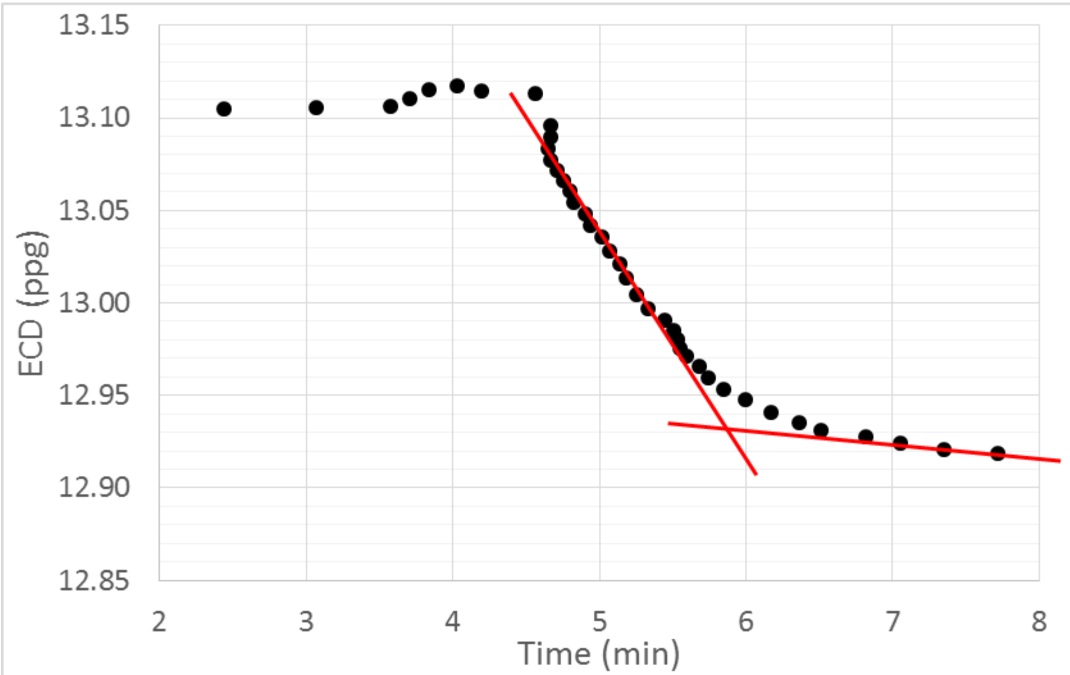

Figure 5.8: Minimum horizontal stress estimation for connection on GOM well 3 (Data from Edwards, Bratton, and Standifird, 1998)

5.2.4 Gulf of Mexico, Well 4

Nagy et al. (2013) published a paper concerning geomechanical modeling in the Gulf of Mexico and include PWD data for a well which experienced wellbore breathing. The PWD data for two connections is plotted below in Figure 5.9 and Figure 5.10. Similar to the prior examples shown, the early linear period is distinct and easy to identify while the late linear period is more indistinct and difficult to identify. The minimum horizontal stress is estimated to be 15.29 ppg using the data from the first connection in Figure 5.9

and 15.295 ppg using the data from the second connection in Figure 5.10. These estimates are similar, but more data points would be useful in confirming the validity of the estimates as the late linear period is not distinct in either of these data sets.

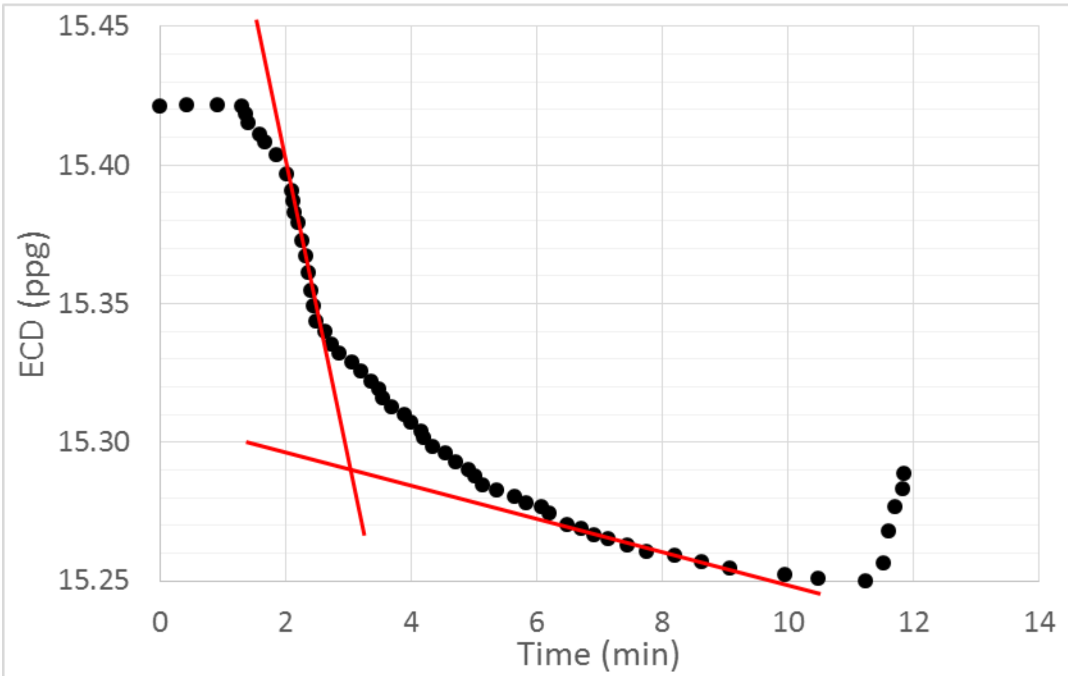

Figure 5.9: Minimum horizontal stress estimation for first connection on GOM well 4 (Data from Nagy et al., 2013).

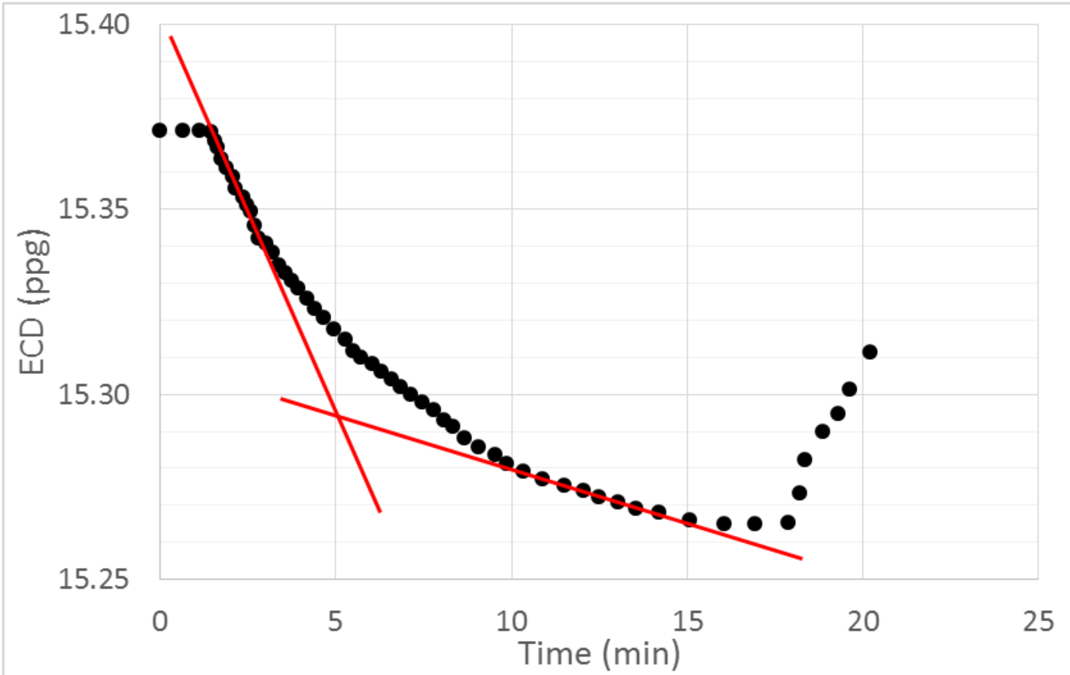

Figure 5.10: Connection with wellbore breathing (Data from Nagy et al., 2013).

5.2.5 Offshore Nova Scotia Well

Marland et al. (2007) published a case study regarding deepwater subsalt well off the coast of Nova Scotia, Canada. The section that experienced wellbore breathing was directly below the salt body and believed to be related to the pressure perturbation caused by the salt. The breathing occurred in the 14” hole section and a LOT had been performed at the casing shoe prior to drilling out, which indicated a fracture pressure of 13.6 ppg. The pressure data for a connection during this hole section is shown in Figure 5.11. A distinct linear trend can be seen both early in the flowback and late in the flowback, which provides for relatively easy interpretation. The minimum horizontal stress is estimated to be 12.592 ppg in this case, which is a full 1 ppg below the LOT performed at the top of hole section.

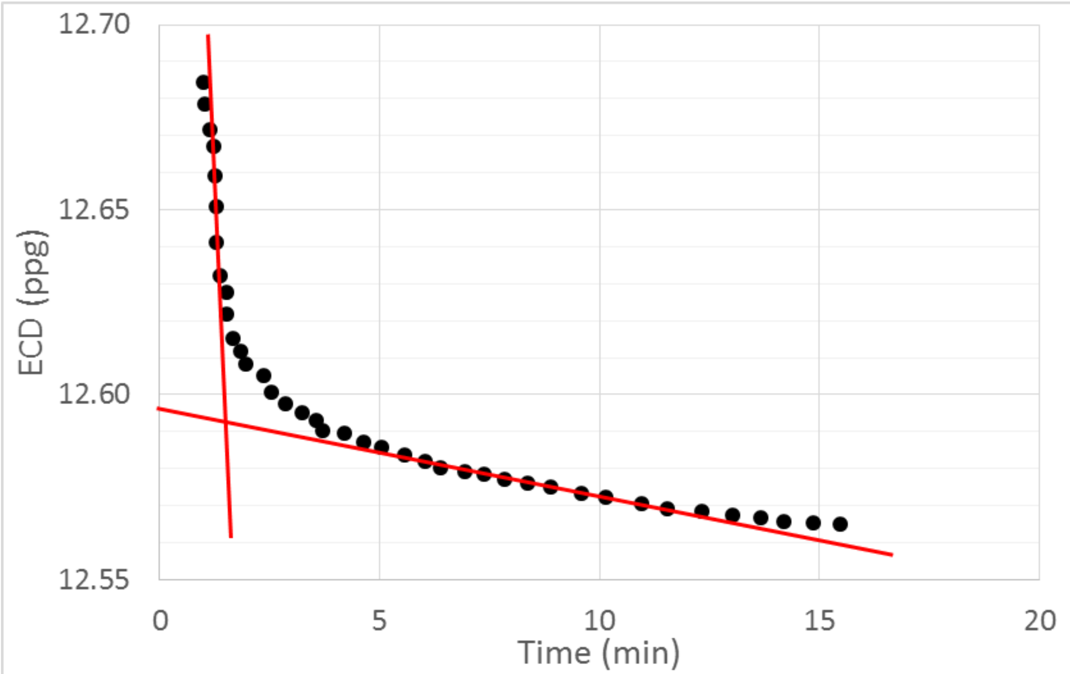

Figure 5.11: Minimum horizontal stress estimation for Nova Scotia well (Data from Marland et al., 2007)

5.3 Application of Minimum Horizontal Stress Estimations

The method for minimum horizontal stress estimations using PWD data during wellbore breathing events proposed in the last section can provide valuable data for better understanding the earth stresses in a given area. While the PWD connection data is not available in real-time, it can be used to better plan the remainder of the well once the BHA is tripped out to surface and the data downloaded. If quickly interpreted, the minimum horizontal stress estimates can be useful in properly designing the cement design on that hole section. Additionally, the minimum horizontal stress estimations can be used to calibrate the pore pressure/frac gradient model on the well. This should yield better estimates of the fracture gradient for the next hole section. In the case that this new data alters the well design in some way, this also provides extra lead time for contingency plans.

The minimum horizontal stress estimation are most useful for calibrating geomechanical models to better predict the stresses in the region. Typically, the values obtained in LOT's are used in these geomechanical models for calibration. However, LOT's are often difficult to interpret and can provide poor stress estimates, while pump-in flowback tests are easy to interpret and have been shown to provide more accurate stress estimates (Økland et al., 2002). Since wellbore breathing events are essentially the same process as a pump-in flowback test, they should also provide better stress estimates if interpreted correctly. Better calibrated geomechanical models can be extremely useful for future wells as it will enable better well planning, casing design, and well placement.

Chapter 6: Conclusions and Recommendations

6.1 Case Studies

The three case studies presented in this work provide useful context to wellbore breathing scenarios that may be encountered in the field, how these mechanisms can present themselves at surface, and some potential pitfalls to avoid when wellbore breathing is encountered. The Jura-1 case study was especially useful in exemplifying the dangers present when wellbore breathing is coupled with hydrocarbon swap-out. Furthermore, this case study stressed the importance of proper interpretation of shut in pressures during well control situations as misinterpretation of the pressures ultimately resulted in the loss of this well. Last, the successful drilling of the subsequent Bard-1 well showcased the effectiveness of a well-trained and educated crew in combination with sound operational procedures in handling wellbore breathing during drilling operations.

The ESS-107 case study was useful in representing the difficulty in identifying overpressure and wellbore breathing when they are encountered consecutively within the same hole section. Additionally, this case study illustrated the need to use correctly calculated kill mud weights as using a higher mud weight to be safe can result in exceeding the minimum horizontal stress. Last, this case study was useful in showing the effects thermal stress changes can have in a well control situation as the fluid gains during static conditions late in the well control sequence were likely caused by the warming of the formation forcing drilling fluid out of the fractures.

The 22/30-C-10 case study shows the significant impacts that the often neglected thermal regime can have on wellbore integrity. The initiation of wellbore fractures was caused by a reduction in the effective fracture gradient due to cooling and these fractures were then propagated with subsequent increases in mud weight. This case study also exhibited the coupled relation of wellbore breathing with both pressures and temperatures. Some of the wellbore breathing was driven by pressure fluctuations between static and circulating conditions, but other instances of drilling fluid flowback from the fractures were driven by thermal stress changes as the formation warmed and closed the fractures.

6.2 Identification, Mitigation, and Prevention

As far as real-time identification while drilling, the best current method is likely flowback finger printing but this method can only identify an increase in connection flowback volumes and cannot differentiate between a kick and wellbore breathing, just identify that one is occurring. PWD measurements offer the best potential for real-time identification of wellbore breathing as well as differentiation between breathing and kicks, but current downhole data transmission technologies limit it to use in post well analysis. Eventual implementation of wired pipe technology would eliminate the data transmission limitation and allow PWD to be used for true real-time identification of wellbore breathing and differentiation between breathing and kicks. The identification section also provided examples of SIDPP and SICP behavior for several different scenarios and explained how these pressures can be interpreted to differentiate between wellbore breathing and a kick.

In terms of mitigation, ECD management is the best method to reduce the effects of wellbore breathing during drilling operations. ECD management can be used to lessen the magnitude of fluid gains and losses from breathing and to decrease the rate at which these gains and losses occur. Bridging or plugging the fracture can also be deployed as a mitigation technique, but this can be time consuming, expensive, and sometimes ineffective.

For prevention, in conventional drilling, focus must be on keeping wellbore pressures to a minimum and monitoring fluid and bottom-hole temperatures to ensure that the formation is not weakened significantly by cooling. In effect, the goal for conventional drilling operations should be to maximize the available fracture gradient through prudent operational procedures. Both managed pressure drilling and continuous circulation systems provide the prospect of eliminating downhole pressure fluctuations and therefore the wellbore breathing mechanism associated with those fluctuations. However, each require some incremental cost to install and operate. This has limited the implementation of these systems in areas where they are not absolutely needed. For instance, MPD is widely used in the Asia Pacific region, but this is only because narrow drilling margins make conventional drilling of many reservoirs impossible.

6.3 Estimation of Minimum Horizontal Stress Using PWD

This work details the theoretical background pertaining to the interpretation of pump-in flowback tests in hydraulic fracturing developed by Plahn, Nolte, and Miska (1997). Using this interpretation, minimum horizontal stress estimations were made using PWD measurements from wellbore breathing published in literature. The estimations obtained for each of these wellbore breathing events was validated qualitatively, when possible, by comparing across multiple connections and comparing with LOT data. These estimations of minimum horizontal stress can provide value to industry by enabling calibration of geomechanical models to better predict the earth stresses within this area.

This will allow better well design and well placement and can potentially provide value for production operations and reservoir engineering if the wellbore breathing events occur near or in a hydrocarbon reservoir.

6.4 Future Work

While the method proposed for estimation of the minimum horizontal stress using PWD measurements during wellbore breathing events was validated qualitatively, it requires further validation across a larger data set. Furthermore, comparison against a more common method for minimum horizontal stress estimation would be useful. Last, development of a full model of the wellbore breathing mechanism would be a useful endeavor. This could provide details about the mechanism itself and could be used to evaluate the accuracy of the proposed method in its estimation of the minimum horizontal stress.

List of Acronyms

BHA: Bottomhole assembly

BHP: Bottomhole pressure

BOP: Blowout preventer

CFS: Continuous flow system

DGD: Dual gradient drilling

ECD: Equivalent circulating density

EMW: Equivalent mud weight

FCP: Fracture closure pressure

FIP: Fracture initiation pressure

FIP: Fracture initiation pressure

FIT: Formation integrity test

FPP: Fracture propagation pressure

GOM: Gulf of Mexico

HPHT: High pressure high temperature

ISIP: Instantaneous shut-in pressure

JIP: Joint industry project

LCM: Lost circulation material

LOT: Leak off test

LP: Limit pressure

LT: Limit test

LWD: Logging while drilling

MAASP: Maximum allowable annular surface pressure

MLP: Mudlift pump

MPD: Managed pressure drilling

MPT: Mud pulse telemetry

NPT: Non-productive time

OBM: Oil based mud

PMCD: Pressurized mud cap drilling

PSP: Pump stop pressure

PWD: Pressure while drilling

RCD: Rotating control device

ROP: Rate of penetration

SBM: Synthetic-oil based mud

SG: Specific Gravity

SICP: Shut-in casing pressure

SIDPP: Shut-in drill pipe pressure

SMW: Static mud weight

SPU: Solids processing unit

TD: Target depth

TVD: True vertical depth

UFP: Uncontrolled fracture pressure

WBM: Water based mud

XLOT: Extended leak off test

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