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Simulation study evaluating alternative initial responses to formation fluid influx during managed pressure drilling

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SIMULATION STUDY EVALUATING ALTERNATIVE INITIAL RESPONSES TO FORMATION FLUID INFLUX DURING MANAGED PRESSURE DRILLING

A Thesis

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ABSTRACT

Managed pressure drilling is an innovative technique to precisely manage wellbore pressure. It is particularly applicable for reducing the risk of a kick or lost returns when drilling with a narrow window between pore pressure and fracture pressure. The constant bottomhole pressure method of managed pressure drilling uses annular frictional pressure and choke pressure in addition to mud hydrostatic pressure to achieve precise wellbore pressure control.

This project investigated alternative initial responses to kicks to determine which would be most effective and reliable under different well scenarios when applying the constant bottomhole pressure method of managed pressure drilling. Three different initial responses to a kick, 'shut-in the well', 'apply back pressure' and 'increase mud pump rate' were studied using an interactive transient multiphase flow simulator. The kick scenarios were varied by changing the hole size, type of kick fluid, initial kick volume, pressure differential at the kick zone, and fracture injectivity index.

No single best response was identified for the kick scenarios that were studied. Nevertheless, some conclusions were reached. The validity of these conclusions may be limited to the range of scenarios studied.

'Increasing mud pump rate' is advantageous when it increases bottomhole pressure enough to stop formation flow because it results in the minimum casing and shoe pressures. Therefore, it should minimize the risk of lost returns or surface equipment failure. However, it is unlikely to be successful in large hole sizes.

The 'apply back pressure' response has a similar but smaller advantage versus the 'shut-in' option because circulation creates friction in the annulus. However, in cases

where lost returns occurred, no reliable way of identifying the loss of returns and avoiding unintentional formation flow to the surface was defined.

The ‘shut-in’ reaction generally results in the highest casing and casing shoe pressures. Therefore, it may be most likely to cause loss of returns before stopping formation flow and consequently causing an underground transfer with continuous influx. Nevertheless, it is probably the least likely to unintentionally allow formation fluid flow to the surface or to cause loss of significant mud volume downhole.

1. INTRODUCTION

1.1 Drilling Challenges with Narrow Pore Pressure-Fracture Pressure Window

Drilling with a narrow window between the pore pressure (PP) and the fracture pressure (FP) is always problematic as it is difficult to manage the wellbore pressure to fit within the window using conventional drilling techniques. A simultaneous or alternating loss and kick scenario while drilling such wells with conventional methods is a common concern. Often wells where this occurs are abandoned because it was not possible to mitigate the problem.

Conventional drilling relies solely on mud hydrostatic pressure to manage the wellbore pressure to fit the PP-FP window at all times during drilling of the well. In a successful conventional well design, sufficient trip and kick margins must be provided for well safety during drilling and tripping including well control operations in the event of a kick. Often, minimum trip and kick margins are prescribed by the regulatory agency to ensure safe operations.

Imposition of minimum safe trip and kick margins in an already narrow PP-FP window makes the available mud weight window even smaller. That results in drilling comparatively shorter hole intervals before being required to run casing to protect the wellbore from lost returns. As a result, the number of hole sections and protective casing strings required to reach the well target depth increases. Consequently, the cost of the well increases due to longer drilling time and the higher cost of casing and accessories. Often, in a conventional well design with a narrow PP-FP window, the size of the production casing becomes very small due to the requirement for a large number of protective intermediate casing strings in the well. The lower production rate consequent to the small production casing size may be uneconomical in a high capital and operating cost environment. Furthermore, drilling a small diameter hole is difficult due to various technical and operational constraints such as high circulating pressure, difficulties in drill bit torque transmission, high drag in the open hole, susceptibility to drillstring sticking etc. Operations such as wireline logging, running and cementing casing, and running completion equipment also experience great difficulties in small size holes.

Typically in deepwater prospects, pore pressures are abnormally high at relatively shallow depths below the sea floor due to rapid sedimentation and lack of compaction. On the other hand, the fracture pressures are typically low because of less overburden owing to large column of water instead of denser sediments. This results in a narrow window between the pore pressure and the fracture pressure. However, deepwater prospects are generally more rewarding in terms of the size of the field, rate of production and the net reserve in comparison to shallow water prospects[40]. Often, pressure depletion in a mature field reduces the effective mud weight window posing similar drilling challenges.

1.2 Managed Pressure Drilling Concept

The IADC definition of managed pressure drilling (MPD) is as follows[3].

"MPD is an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly."

MPD techniques for precise control of wellbore pressure are considered to be an acceptable solution in a downhole environment with a narrow window between pore pressure and fracture pressure, which, if successfully implemented can reduce trouble time and well cost substantially. This method endeavors to manipulate wellbore pressure in such a way that a longer hole section can be drilled without fracturing overlying formations than possible with conventional drilling.

The concept of MPD is related to underbalanced drilling (UBD), where the wellbore pressure is deliberately kept lower than the pore pressure during drilling. UBD is an applicable technology to successfully drill low productivity reservoirs without causing formation damage. Also, underbalanced drilling may produce hydrocarbon during drilling which needs to be handled at the surface requiring special equipment. The underlying difference between MPD and UBD is that the MPD does not intend to cause formation fluid flow into the wellbore during drilling, and therefore, always seeks to maintain a slight overbalance in the wellbore.

1.3 Constant Bottomhole Pressure (CBHP) Method of MPD

Among the various forms of MPD methods, the CBHP method utilizes and manipulates choke pressure and wellbore frictional pressure in a closed drilling system to always maintain a constant bottomhole pressure (BHP), slightly above the pore pressure. The closed drilling system utilizes a rotating control head (RCH) and an adjustable drilling choke through which the return mud is circulated enabling back pressure to be applied to effectively control the BHP. A simple sketch illustrating the operation of a RCH is shown in Figure 1.1.

The BHP has three components: hydrostatic pressure, annulus frictional pressure (AFP) and choke pressure in a closed circulating system. The CBHP technique is intended to utilize the combination of these three pressure components for precise wellbore pressure management at all times during drilling. Figure 1.2 illustrates these three components of BHP and the variables that effect the magnitude of these pressure components.

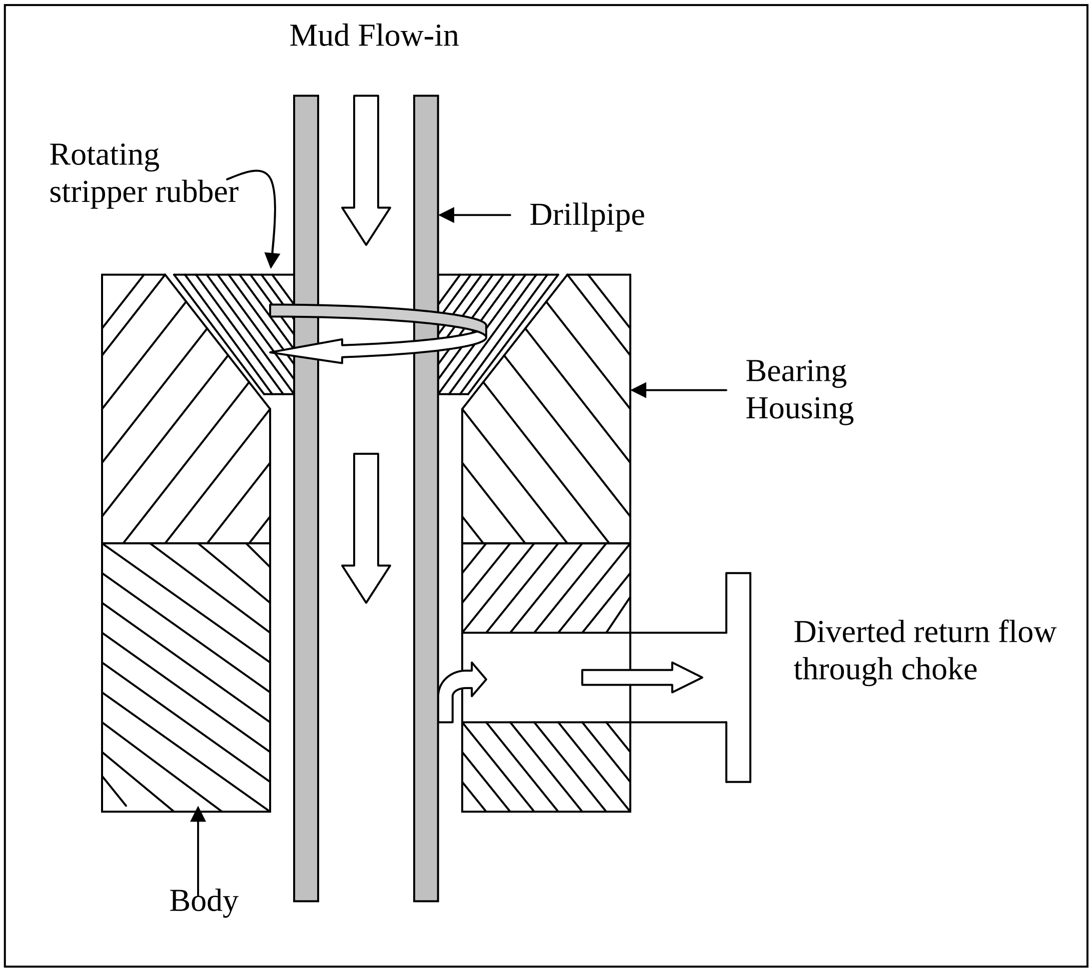

Figure 1.1: Rotating control head

The variables such as mud flow rate which controls the AFP and choke pressure which controls the back pressure can be manipulated in real time during drilling allowing relatively quick changes in the wellbore pressure. Conversely, changing the magnitude of the mud properties, such as mud weight and viscosity, has a more delayed impact. The borehole annular geometry also has an important role in determining the AFP in the well, but cannot be changed without tripping the drillstring. The AFP losses will be higher as the clearance between the wellbore and the drillstring become smaller.

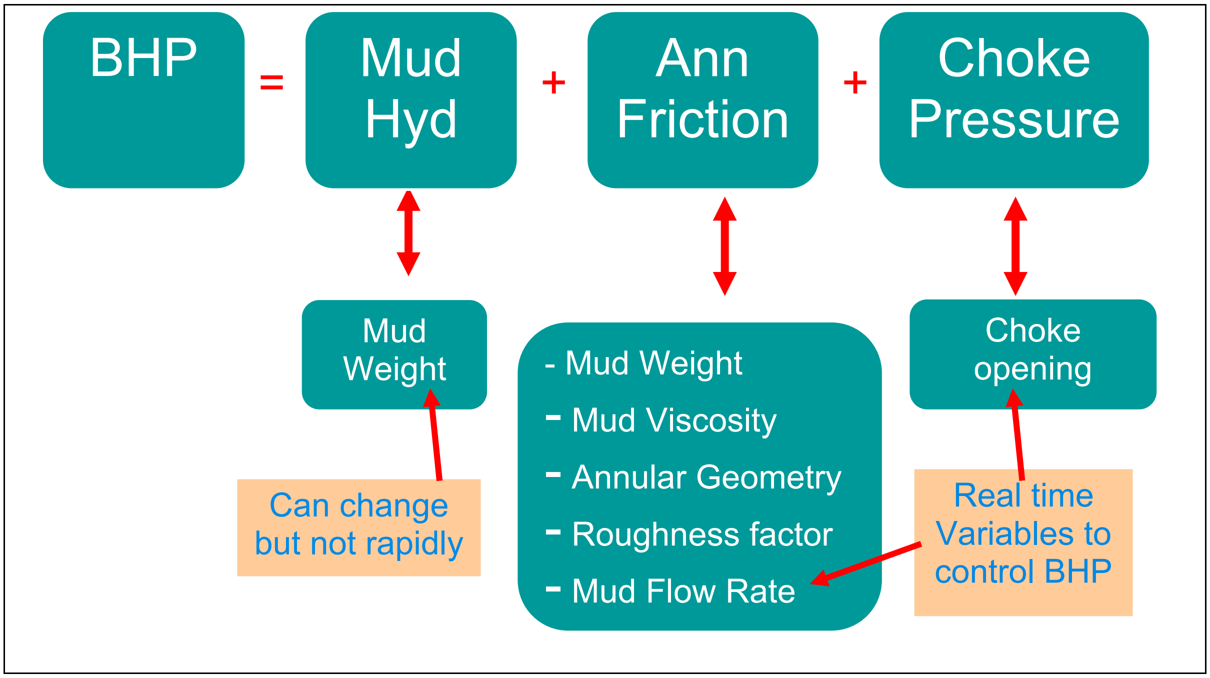

Figure 1.2: Components of wellbore pressure

Figure 1.3 illustrates the conceptual differences in the wellbore pressure profile for the CBHP method of MPD versus conventional drilling. The wellbore pressure is maintained slightly higher than the pore pressure during drilling by a combination of mud hydrostatic pressure and the AFP or by a combination of mud hydrostatic pressure, AFP and back pressure applied through the choke in a typical CBHP operation. In this form of drilling, the mud hydrostatic pressure alone may not be sufficient to maintain an overbalance over the pore pressure as in case of conventional drilling. This implies that in CBHP well design, static mud weight (MW) is normally kept lower than the pore pressure gradient as opposed to conventional drilling. During pipe connections, when mud circulation is stopped, back pressure may be applied through the choke to compensate for the loss of annular frictional pressure component, so that an overbalance is maintained at all times.

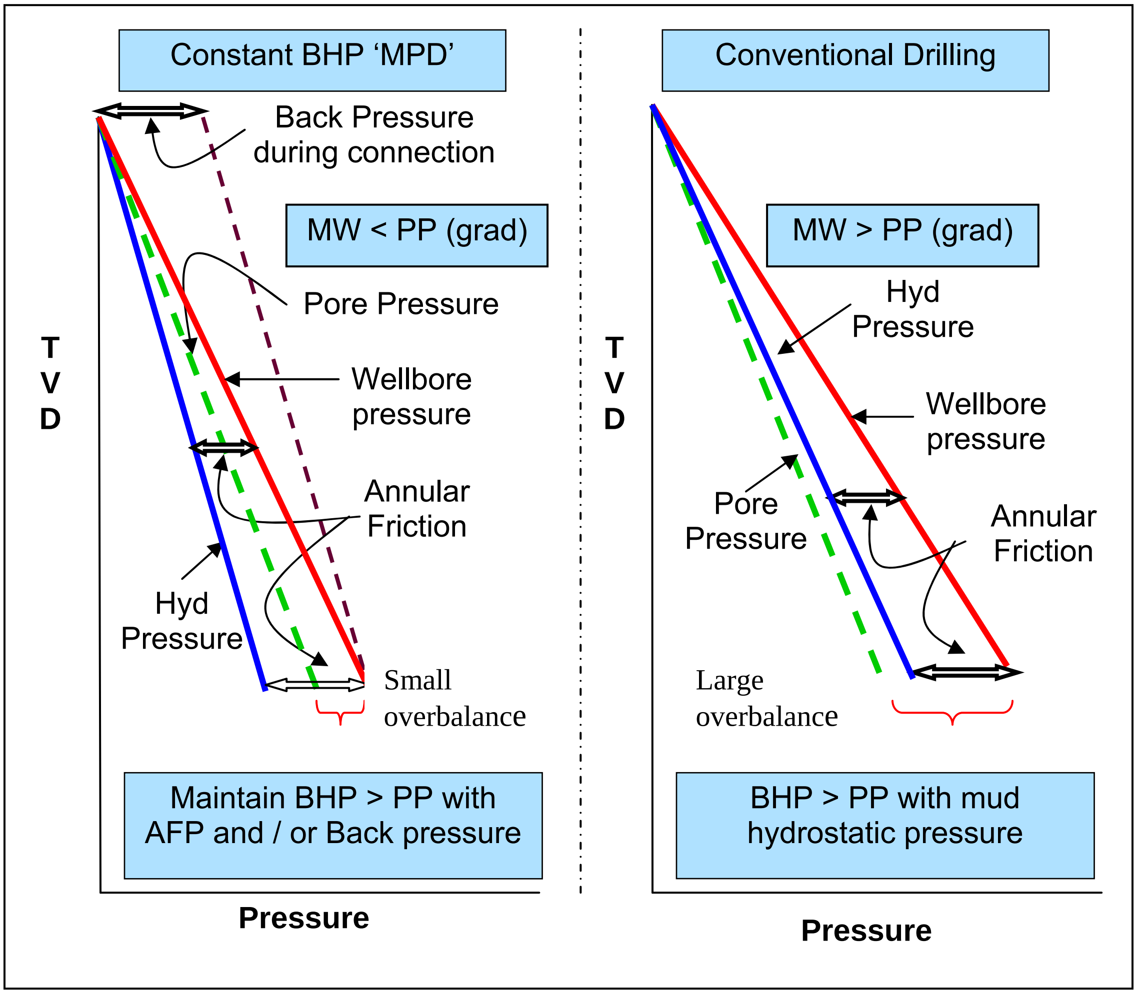

Figure 1.3: CBHP method of MPD against conventional drilling

There are other forms of MPD namely dual gradient drilling, pressurized mud cap drilling, riserless drilling and zero discharge riserless drilling in addition to CBHP method of MPD; all seek to manage the wellbore pressure profile to fit the specific PP-FP window. The exact methodologies of these forms of MPD are not discussed here as being outside the scope of this research.

1.4 Application of CBHP Method of MPD

The CBHP method of MPD can be useful in several applications in addition to the application in narrow mud weight window, which is common in deep water drilling. Some of these specific applications are described below.

1.4.1 Slim-hole Drilling in Reentry Sidetrack Well

Due to the tight annular geometry in slim hole drilling, AFP is high, which results in a high equivalent circulation density (ECD). The hole sizes in reentry sidetrack wells with the objective of producing from deeper prospects are often small. These types of wells need precise wellbore pressure management in order to drill a stable wellbore without inducing a kick or fracturing a weak formation. In this type of MPD application, the MW is generally kept lower than the pore pressure gradient and the overbalance is maintained with ECD.

1.4.2 Drilling through Depleted Zone

Conventional drilling through a depleted zone with an overlying high pressure formation in a typical PP-FP window may cause lost returns due to high wellbore pressure against the depleted zone while overbalance is maintained at the high pressure formation. This problem may be mitigated by controlling the wellbore pressure precisely by CBHP operation so that the fracture pressure at the depleted zone is not exceeded while overbalance at the high pressure zone is still maintained. Similarly, if a high pressure formation is penetrated with an overlying depleted zone, CBHP operation may be able to maintain the well bore pressure within the required window that doesn't exceed the fracture pressure at the depleted zone and maintains overbalance at the high pressure zone. A proper combination of hydrostatic pressure, AFP and back pressure will be required for such precise control of the wellbore pressure.

The above applications of the CBHP method of MPD are a few common applications in typical wellbore pressure environments. However, this technique of MPD can be planned in any drilling environment where precise wellbore pressure management is desired.

1.5 Well Control Issues for the CBHP Method of MPD

The success of the CBHP method of MPD relies upon accuracy in pore pressure and fracture pressure predictions. Reliable pore pressure and fracture pressure data often are not available for an exploration prospect. In a producing field, reservoir pressure changes with time. Similarly, the pore pressure and the fracture pressure in a mature field are unlikely to remain constant over time. Therefore, an envelope of uncertainty of the pore pressure and the fracture pressure of the formations almost always exists while drilling a well.

Presently, fracture pressure measurement is typically accomplished by conducting a leak off test (LOT) after drilling out the shoe of a casing string. Also, integrity of the formation can be tested dynamically to a pre-determined pressure during drilling if a pressure while drilling (PWD) tool is installed in the bottom hole assembly (BHA). With the latest advancement of logging while drilling (LWD) technology, pore pressure measurement is also possible during drilling. However, these tools can not predict the anticipated pore pressures and fracture pressures of the formations to be drilled. Therefore, the risk of a kick or lost returns during CBHP operation is significant, especially if the PP-FP window is narrow.

A narrow PP-FP window will often require drilling with a small kick tolerance, resulting in an increased risk of losing returns during a well control operation. Therefore, MPD wells may be more susceptible to under ground blowouts than conventional wells.

Consequently, the well control issues for CBHP operations need careful attention for successful implementation of this technology.

1.6 Overall Research Objective

The overall objective of the project , of which this research is a part, is to establish comprehensive, reliable well control procedures for the CBHP method of MPD operations equivalent to or better than, those currently in use for conventional drilling operations. The project is financially and technically supported by a consortium, comprised of major oil companies and an established UBD consulting company. The tentative duration of this project is 3 years.

In order to accomplish the research objective, fundamental research will be carried out to determine (1) the best initial response to a kick, (2) an appropriate kick circulation procedure after stopping the formation influx, (3) a way to identify a threatened underground blowout, and (4) an appropriate initial response to a threatened underground blowout.

The validity of the results of this research is expected to be demonstrated in a real well at the LSU Petroleum Engineering Research and Technological Laboratory.

1.7 Specific Research Objective

The specific objective of the research described herein is to determine the best initial response to a kick under different well control scenarios as a part of the overall research objective.

The conventional well control procedure, after a kick is taken into the wellbore, requires shutting-in the well for stopping the formation fluid influx into the wellbore. Since the CBHP type of MPD is undertaken in a closed circulating system with pressure containment at the rotating control head, and return flow diverted through the drilling choke, alternative types of initial responses to a kick can possibly be undertaken without sacrificing the safety of the crew and the rig. The specific objective of this research is to study the effect of alternative initial responses to a kick taken during CBHP method of MPD in order to determine the best initial responses to different kick scenarios.

The various alternative initial responses that will be studied under this research are discussed in chapter 4.

1.8 Overview of Thesis

Chapter 1 introduces the concept of CBHP method of MPD and associated well control issues, explains the need for a detailed study of alternative well control procedures to determine the best practices under MPD applications and describes the work involved in the project.

Chapter 2 reviews the existing literature on MPD and associated well control issues.

Chapter 3 gives an account of the research plan and describes the methodology to perform the research. This includes a description of various tasks performed during the research and the description of the software (simulator) used to simulate well control scenarios for studying the effect of various initial responses to an oil or gas kick in the well. The main features of this software, input data requirements, simulator evaluation and simulation method used in this study are also discussed in this chapter.

Chapter 4 describes the various initial responses subsequent to kick detection for stopping the formation fluid influx into the wellbore. The potential advantages and disadvantages of various initial responses and their expected suitability for different kick scenarios are discussed.

Chapter 5 describes the simulation studies of representative well X. The results of simulations are analyzed and presented in this chapter.

Chapter 6 describes the simulation studies of representative well Z. The results of simulations are analyzed and presented in this chapter.

Chapter 7 analyzes the important results of simulations undertaken during this study. The effectiveness of each initial reaction in achieving the desired functions, specifically to stop formation feed-in, prevent lost returns, confirm stoppage of influx and identify lost returns, is discussed in this chapter.

Chapter 8 summarizes the study with overall conclusions including a discussion on the best initial reaction based on the simulation results and recommendations for future research.

2. LITERATURE REVIEW

A literature review was performed to fully understand the concept of CBHP method of MPD and its applications. Since the MPD method originated from the concept of underbalanced drilling, relevant published literature on underbalanced drilling was also consulted. Special emphasis was placed on the well control aspects of CBHP method of MPD operations. No publication on research to devise proper well control procedures for CBHP method of MPD to make this form of drilling safe relative to conventional operations was found in the literature search. An overall summary of the findings from the literature review is included in the following sections.

2.1 MPD General Concepts

Hannegan [3]gave an overview of MPD as an emerging technology. He explained the conceptual difference between UBD, MPD and power drilling (PD) for ROP enhancement. The various forms of MPD as a means of wellbore pressure management such as dual gradient drilling, pressurized mud cap drilling, riserless drilling and zero discharge riserless drilling were explained. However, the well control issues associated with MPD were not discussed in this literature.

Fossil[4] described controlled mud cap (CMC) MPD technology for deepwater offshore applications. The system utilizes an engineering simulator to calculate the dynamic pressure losses in the wellbore during drilling and controls the speed of the mud-lift pump at the sea floor in real time to maintain the required mud level in the riser to control the BHP. In this system, during pipe connection, the effect of loosing friction during pipe connection is compensated by varying the level of fluid in the riser to maintain the same BHP same as during drilling.

Hannegan[9] discussed the potential application of MPD to precisely manage wellbore pressure to avoid methane hydrate dissociation while drilling through hydrate reservoirs.

Bern[16] described the development of a prototype downhole ECD reduction tool for MPD application. However, well control aspects of managed pressure drilling were not discussed.

Johnson[17] discussed a methodology of riserless drilling, a form of MPD for the surface casing interval using low cost, sacrificial, weighted, dynamic kill drilling (DKD™) fluids prepared with seawater. The advantage of using the DKD system is the ability to drill a comparatively longer section of stable surface hole into abnormally pressured formations so that the depth of surface casing and the subsequent intermediate casings can be pushed deeper. In a narrow PP–FP window, ability to push the surface casing deeper may result in less number of intermediate casings and a comparatively larger size production casing to achieve a higher production rate. Well control methods that might be generally applicable to the CBHP method were not described.

Cantu[19] described the selection criteria, operational issues and maintenance of RCH in MPD application. Well control issues of MPD were not discussed in this literature.

Quitzau[28] introduced a concept of managing wellbore pressures by drilling with large-diameter liner as part of the drill string. In this concept, the hole is drilled with a conventional drillstring to traditional kick tolerance limit. The drill-in liner is then run, mud weight is reduced and drilling continues. Circulating friction pressure around the liner raises ECD near bottom of the hole while the ECD in the shallower section is smaller due to larger annular clearance. The ECD profile may be managed within the pore pressure fracture pressure window by adjusting static mud weight and circulation rate.

2.2 Well Control

Saponja[1] addressed the question whether or not to close the BOP on a gas flow during UBD operations with surface facilities to handle the gas. Saponja refers to these as MPD operations. He has suggested a field specific flow control matrix (FCM) that would determine the severity of the well control hazard and recommend the well control measures to follow. The flow control matrix specific to the example well is reproduced here at Table 2.1 for a better insight.

Table 2.1: Flow control matrix (after Saponja[1])

		WELLHEAD FLOWING PRESSURE		
		0-3447 kP_a	3447-4800 kP_a	4800+ kP_a
RETURN GAS RATE	(0-594) $10^3\ m^3$/day (0-21) MMscfd	Manageable	Adjust system to increase BHP - Increase liquid injection rate - Decrease surface back pressure	Shut-in on Rig's BOP
	(594-892) $10^3\ m^3$/day (21-31.5) MMscfd	Adjust system to increase BHP - Increase liquid injection rate - Increase surface back pressure	Adjust system to increase BHP - Weight up drilling fluid	Shut-in on Rig's BOP
	(892+) $10^3\ m^3$/day (31.5+) MMscfd	Shut-in on Rig's BOP	Shut-in on Rig's BOP	Shut-in on Rig's BOP

The severity of the hazard is gauged by the return gas rate and flowing wellhead pressure. The well control measures are: change liquid injection rate, change surface back pressure, weighting up of drilling fluid or shut in the well. On the contrary, the Minerals Management Services (MMS)[44] have proposed that GOM lessees be required to revert to conventional well control with the BOP and primary choke manifold if a kick is detected in a MPD operation.

Bode[7] discussed well control methods and practices in slim-hole drilling. He explained the effectiveness of dynamic killing in slim hole drilling because of higher AFP. He recommended to routinely determine AFP during drilling to gain knowledge about hole wash-outs to determine whether dynamic killing will be effective or not. He recognized that for a large volume of gas influx, dynamic killing will be less effective because of less frictional pressure losses due to light density gas. He emphasized the use of sensitive quantitative electromagnetic flow meters for early kick detection in slim hole drilling. He described the technique of superimposing flow-out and flow-in plots as a means to identify kick in a computerized system.

Codazzi [36] suggested an advanced early detection technique for gas kick based on measuring the travel time of sonic pressure wave generated by the mud pump. The algorithm behind this early gas detection technique is that the presence of gas significantly reduces the speed of sound in mud. The pressure pulses generated by the mud pump are measured by transducers installed in two locations, one in the standpipe and the other just below the bell nipple. The system detects and monitors the sonic travel time between these two transducers, which is fairly constant during normal drilling operation and changes exponentially when the density of mud reduces substantially with influx of gas into the wellbore. The system can detect gas influx very early for both water-based and oil-based mud as in both cases the density of mud is reduced substantially effecting the sonic travel time. However, the system can not detect a liquid kick. The paper claimed to have detected gas influx as early as only one-half barrel of pit gain.

Bryant[37] described early detection of gas influx by measurement while drilling (MWD) using a similar acoustic principle of varying sonic travel time in different density fluid. This technique can distinguish between drilled gas and gas influx caused by underbalanced situation with different signature of MWD pulses.

The ability to detect the kick early is important to maintain an intact wellbore in a narrow PP-FP window with low kick tolerance during the well control operation. Surface detection of a kick by the conventional volumetric methods is not very conclusive for a small increase in return flow and / or pit volume because of low system accuracy. Therefore reliable and early down hole kick detection by an advanced tool could be very useful for MPD operations.

Shaughnessy[20] discussed the well control issues associated with ultra deep high-temperature, high-pressure drilling. He has identified “swabbing on trips”, “ballooning formations”, “low permeability kicks”, “liner top failure”, “flow after cementing” and “casing wear” as the main problems that need to be addressed to minimize potential well control problems.

Ward[31] describes the capability of a pressure while drilling (PWD) tool to help identify and evaluate the severity of alternating losses and gains associated with formation ballooning. Also, the PWD tool will accurately determine equivalent mud weight (EMW) in a well, even when there is a non-homogeneous mud in the annulus. PWD tool can also accurately record pressures during a lost circulation event, and swab and surge pressure during tripping.

2.3 Underbalanced Drilling

Bourgoyne[10] gave an overview of the difference in well control procedures between conventional drilling and UBD and emphasized the requirement for training on UBD well control procedures. However, the well control issues associated with MPD were not discussed in this literature.

Mykytiw[12] discussed the use of UbitTS^{TM}, the underbalanced multiphase transient flow simulator, for design and implementation of UBD by gas injection through concentric casing. However, use of UbitTS^{TM} for study of MPD well control issues was not discussed in this literature.

Sotherland[21] described the usage of a downhole deployment valve (DDV) in underbalanced drilling. With incorporation of a DDV, the well need not to be killed before tripping. Conventional tripping in open system is possible with closed DDV, and a pipe light situation can be avoided. The drillstring must be stripped in and out below the DDV, but the requirement to strip a BHA, which is impractical due to its geometry, is avoided with a DDV installed. Another advantage is that a sand screen can be run with a DDV installed, which otherwise is not feasible in an underbalanced well. A special DDV equipped with downhole sensors and mono conductor braided wireline provides real time downhole pressure below the valve and the valve position. The paper did not discuss well control issues.

2.4 MPD Case Histories

Calderoni[38] described a case history of MPD operation in an exploratory well where uninterrupted circulation was maintained during drilling, pipe connections and tripping using the continuous circulation system (CCS^{TM}). Earlier, conventional drilling was unable to make progress due to alternating gain and loss in a narrow PP-FP window. The well was re-entered to drill an 8-1/2” hole in balanced pressure mode at a constant ECD using CCS^{TM} technology to avoid BHP fluctuation. The main unit of CCS^{TM} is a pressure container constructed from three BOP units, with a combination make/break power tong and snubber at the top and a drill pipe slip at the bottom. The unit is rigged up on the rig floor and located centrally at the rotary table of a top-drive rig. The average time to make a connection by this unit was 21 min.

In spite of maintaining continuous circulation avoiding pressure surges during connections, the ECD could not always be contained within the required mud weight window, and the well experienced alternating loss and gain during drilling. The planned reaction for kicks was to increase circulation rate, but this was not feasible because lost returns were occurring at the present rate. “Over the next 14 days the well was brought under control by a combination of LCM pills and circulating out gas through the chokes until the required mud weight could be established.” After regaining control of the well and running and cementing a 7” liner, a 5-7/8” hole was drilled into the target reservoir using the CCS™. Increasing levels of gas at the surface required closing the annular preventor and bullheading through the drillpipe and bleeding gas from the annulus. Drilling resumed, but a subsequent gas flow required rigging up a rotating control head to allow drilling with continuous lost returns while holding 500 to 800 psi on the annulus. Drilling continued into the top of the target reservoir, and the openhole was then isolated with a cement plug extending up into the 7” liner. After two attempts to complete drilling of the well to target depth with a 5” drill-in liner were unsuccessful, the openhole was secured with cement plugs pending further work.

The above case history highlights the high risk factor associated with drilling in a narrow PP-FP window, even with extensive preparation and MPD equipment, and points to the requirement for an established and reliable well control procedure for such operations.

Wilson[22] gave case histories of three wells in Pompano field, Gulf of Mexico (GOM) and addressed the issues of drilling depleted sands, wellbore instability at high angle, and the associated risks of drilling sub-salt extended reach wells. The author placed emphasis on the necessity of correct prediction of PP–FP window for extended reach drilling where water depth varies considerably between surface and bottomhole location of the well. According to the paper, the typical loss and gain situation resulting from cycling of the pump on for drilling and off for connections, which occurs frequently in deepwater drilling with narrow pore pressure fracture pressure margin, is attributed to induced fractures opening and closing in the wellbore. The literature did not specifically discuss any well control issues.

2.5 New Technologies

Santos[2,47] introduced "micro-flux control", a new technology for constantly managing BHP within the PP-FP window by controlling back pressure as necessary through an automated choke system. The system continuously monitors mud flow-in versus mud flow-out to detect a loss or a kick in the well in real time. An alarm is automatically raised when the difference between the flow-in and the flow-out exceeds a certain specified value, and the control system adjusts the drilling choke to vary the back pressure until flow-in and flow-out equalizes. This equalization implies that influx or lost returns has been stopped, restoring the wellbore pressure within the PP-FP window. The technology claims to be capable of early kick detection with as low as 0.25 bbl of influx, which is favorable for keeping the wellbore pressure low with minimal chance of formation break down during kick circulation.

The system uses a mass flow meter, which is more sensitive and accurate than conventional flow paddle type sensors for measuring return mud flow rate. Once the kick is detected, the system claims to circulate out the kick by automatic choke adjustment keeping the bottom hole pressure constant.

The main challenge of MPD is maintaining bottom hole pressure within the desired range when the pump is turned-off for a pipe connection. The Dynamic Annular Pressure Control (DAPC)[11,32] tool uses a system that can apply additional back pressure on the well with static mud to compensate for the loss of ECD when circulation is stopped. The system incorporates a specially manufactured choke manifold with automated choke control and an auxiliary pump to circulate mud through the choke to apply back pressure in the well. The system is computer controlled, and with the data input from rig monitoring system and/or PWD, a hydraulics calculator calculates the bottom hole pressure requirement and a logic controller automatically controls the auxiliary pump output and choke adjustment to apply the required back pressure to the well. The technology was applied successfully for automated bottom hole pressure control in a deepwater Gulf of Mexico well[32].

Iverson[39] discussed the results of a simulation study of a MPD operation in a high pressure high temperature (HPHT) well to investigate the effect of (1) automatic choke regulation, (2) a continuous circulation device and (3) a mud heater. Application of a continuous circulation device or a mud heater has primarily a stabilization effect on the wellbore pressure profile, while automatic choke regulation is considered as a direct and fast response technique for back pressure application. The simulation results indicate that in case of drilling in the marginal high temperature reservoir, application of a mud heater does not contribute significantly to stabilization of downhole pressure, regardless of the type of mud is used. Application of a continuous circulation device may give great benefit especially in combination with back pressure. During drilling, an automatic linear choke control may secure a nearly constant pressure at target depth. Surge and swab fluctuations will occur during tripping, but this may be significantly reduced by proper tuning of the choke control.

3. RESEARCH METHOD

3.1 Introduction

The overall objective of this study is to develop an understanding of the behavior of both oil and / or gas kicks from the time the kick fluid enters the wellbore to the time the influx is stopped in order to determine the best initial response to a kick. An appropriate initial response to a kick is important for the subsequent well control measures to be effective and successful.

3.2 Research Plan

To accomplish the research objective, work was performed following the plan as detailed below.

1. Existing literature about MPD and associated well control issues was reviewed.

2. Training was received on the underbalanced drilling interactive transient training simulator (UbitTS™) to be used for the simulation studies of alternative initial responses to kick under MPD environment.

3. Descriptions of four offshore wells from different geological areas that were drilled or planned to be drilled in a MPD mode were collected from the project sponsors. The water depth of these wells ranges from 120 ft to 3000 ft. The primary reason for MPD in these wells is a narrow PP-FP window. The high ECD in slimhole drilling and weak depleted zones are the other reasons for MPD in some of these wells. The candidate sections for MPD operations include a range of hole sizes from 6 to 17.5 inches. Out of four wells, one is vertical and three are deviated. The target horizons include both oil and gas reservoirs. The total depth of these wells ranges from 9446 ft to 20,598 ft. Collectively, these wells cover a wide range of well scenarios. However, availability of data from ultra-

deep-water wells and deep, high pressure, high temperature, onshore wells would have constituted a more comprehensive spectrum of representative well scenarios.

4. In a particular well geometry and formation characteristics with a defined PP-FP profile, kick scenarios in a well can be varied by changing a multitude of factors such as differential pressure at the kick zone, productivity index of the reservoir, injectivity index and fracture pressure of potential loss zones, type of reservoir fluid, and type of drilling mud. The kick volume will depend on the kick detection time and the various factors mentioned above. The post-kick well scenario will depend on the size of the kick, the type of drilling mud used in the well and whether lost returns occurred and the severity of losses. Combinations of the above factors will make different well control scenarios possible in any given well.

Various well control scenarios were identified for simulation studies after analyzing the well data received from the sponsors. Different kick scenarios are useful to observe variation of simulation results under different circumstances. In this study, kicks are simulated in one 6 inch slim hole and in one large 17-1/2 inch hole of two different MPD wells. Fictitious names are given for these wells as well: X and well: Z.

5. The main goal of an effective "initial reaction" after kick detection is to stop the formation fluid influx by equalizing the bottomhole pressure with the pore pressure. Two of the most important parameters to judge the effectiveness of an initial reaction to a kick are: additional influx after the initial reaction and the increase of casing pressure required to stop fluid influx. A lower magnitude of these two parameters is favorable for avoiding lost returns and the associated risk of an underground blowout. Two additional, and potentially more important considerations are whether the reaction allows conclusive

determination of whether formation feed-in has stopped and whether the wellbore is intact or losses are occurring downhole. The other useful criteria to judge the effectiveness of the initial kick responses are:

- Ability to determine hydrostatic pressure increment needed
- Minimum kick volume to handle at surface.
- Maximum time before casing pressure is excessive threatening to underground blowout
- Impact of and / or need for special capabilities e.g. PWD tool and flow out metering.
- Ability to identify a kick versus instrument error or formation breathing.

The representative well control scenarios were simulated and different initial reactions were studied. The results of the simulations were analyzed to determine their effectiveness as discussed above. Simulation descriptions and simulation results are provided in chapter 5 for well X and chapter 6 for well Z.

3.3 Well Control Simulator

Hypothetical kick scenarios for representative MPD wells can be simulated in a well control simulator, and the effect of different initial responses to a kick following the time it was detected can be studied. Since there will be multiphase flow of gas and liquid in the wellbore, especially for a gas kick, an advanced simulator with the capability to simulate multiphase flow behavior is required. Also, for a gas kick, as the pressure-temperature-volume (PVT) properties of the gas will be constantly changing as the gas migrates up the wellbore, and the flow from the reservoir will decrease as the wellbore pressure increases, steady-state flow behavior will not be realized. Hence, an advanced, multiphase, transient, well control simulator will be required to truly understand the effect of gas migration in the wellbore.

3.3.1 Transient Multiphase Flow Simulator (UbitTS^{TM})

A transient, multiphase simulator – UbitTS^{TM}, which runs on an OLGA 2000^{TM} engine[49], is used for this study. OLGA 2000^{TM} was originally created for complex, transient pipeline flow problems and was later adapted for well control application by incorporating a new model called the "Advanced Well" module to increase its utility for modeling upstream activities of oil and gas exploration. OLGA 2000^{TM} alone runs only in a batch mode, which means that the user control actions must be decided prior to running the simulation. However, pre-defining changes for well control operations is not practicable and therefore, direct application of OLGA 2000^{TM} for well control simulation is cumbersome. UbitTS^{TM} was developed to add the interactive input capability to OLGA 2000^{TM} for well control simulations, particularly for underbalanced drilling training[12,49,50].

3.3.1.1 Features of UbitTS^{TM}

The Graphical User Interface (GUI) in UbitTS^{TM} shown in Figure 3.1 supports the user with various interactive controls and a real time update of important parameters while the simulations are run by the OLGA engine. Since UbitTS^{TM} was developed for simulating underbalanced drilling, it is designed for simulating drilling, circulating and tripping with a closed circulation system incorporating a RCH and a drilling choke at the surface. A MWD tool can be incorporated in the drill string in order to get a continuous update of bottom hole pressure during the simulation. Also, a drill pipe float can be included in the drill string to prevent a u-tubing effect during pipe connections.

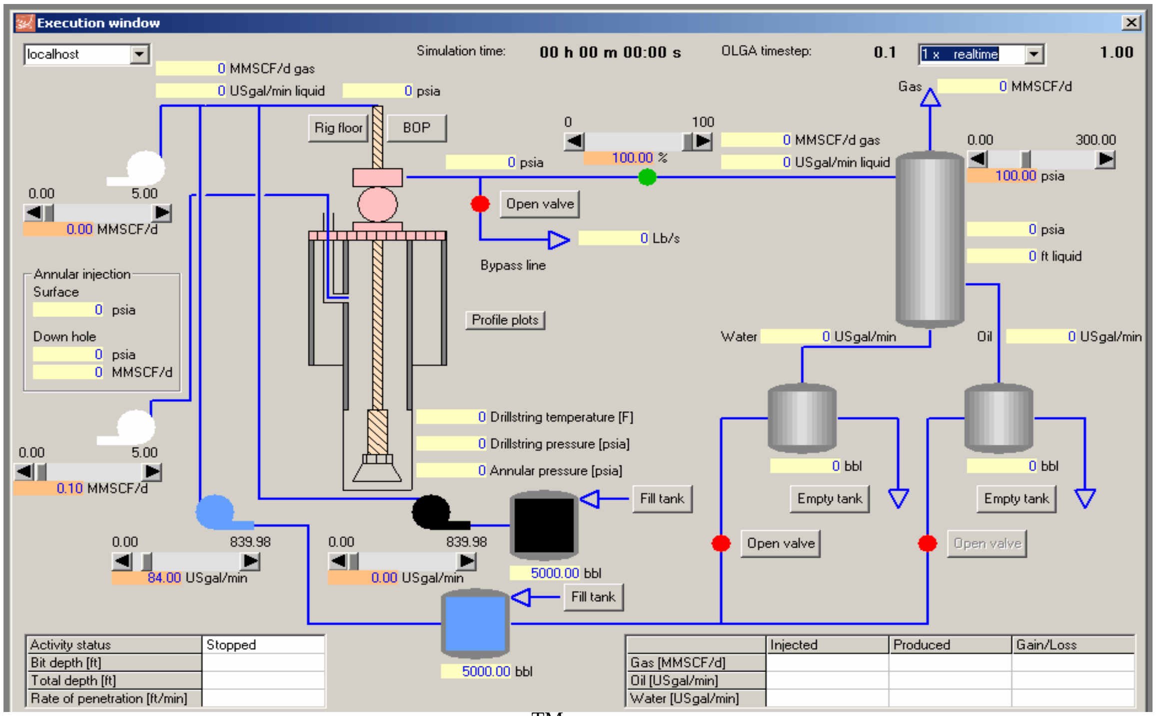

Figure 3.1: UbitTS^{TM} - graphic user interface

The circulating system in UbitTS^{TM} can optionally include a four phase separator down stream of the drilling choke. In addition to the continuous update of useful drilling parameters, updated time-based plots and profile plots of important variables can be seen while running simulations. The variables that are continuously plotted against time include important well control parameters such as drillpipe pressure, bottomhole pressure, choke pressure, flow rate-in and flow rate-out. The various profile plots include the pressure profile, temperature profile, liquid hold-up profile, etc. Liquid injection rate, gas injection rate and the choke opening are the main controls that can be manipulated by the user during a simulation.

3.3.1.2 Simulator Evaluation

Validation of the well control simulator is necessary to have confidence in a simulation study of the effect of various initial responses to kick. UbitTS^{TM} runs on an OLGA engine, which was used earlier in the research on “Analysis of Alternative Well

Control Methods for Dual Density Deepwater Drilling" conducted by Stanislawek[45] for his masters thesis at LSU. He has validated the simulator results against a full-scale experimental data performed by Lopes[46] at LSU. The experiment consisted of injecting nitrogen through a gas injection line and drilling fluid through a separate injection line in a test well. The annular pressures at the bottom of the well were recorded during the unsteady state system behavior in two phase flow during the experiment. Stanislawek[45] found a good match of the transient annular pressure data between the simulator and the experimental results, with a maximum error of 2.5 %.

UbitTS™ was used by Mykytiw[12] to understand the well slugging tendency during underbalanced drilling in order to optimize design of operational parameters to minimize the slugging tendency and pressure instability in the well when a concentric casing gas injection technique was employed. The simulator results were compared with real well data during periods of well slugging using the concentric casing injection method. The validation exercise results were not given, however, it was stated that an "acceptable level of confidence" was established with the model results.

Validation for this research began with simple functional checks. The drilling fluid injection pump of the simulator was tested with designated maximum pressure for a validation check. The pop-off valve of the pump blew out as the stand pipe pressure reached the maximum pressure limit. In another validation check, the drill pipe float was subjected to high pressure from below, and the float held. In a validation check for hydraulics under steady state single phase flow of water-based mud, discrepancies in AFP losses were noted between the simulator results and manual calculations. The results of the simulations are tabulated in Table 3.1. A comparison of AFPs between the simulator results and manual calculations is shown in Table 3.2.

Table 3.1: UbitTS™ simulation results for hydraulics validation

MW	Viscosity	Flow-in	SPP	Drillstring pressure (at bit)	Annular Pressure	Surface Pressure	Flow-out	AFP (ΔP)	Remarks
ppg	cp	Gpm	Psi	Psi	Psi	psi	gpm	psi	
13.2	38	0.3	0	9536	9536	11.34	0	0	
13.2	38	50.11	235	9601	9589	14.53	49.52	53	
13.2	38	100.06	750	9721	9670	14.78	100.9	134	
13.2	38	149.8	1510	9914	9798	15.17	150	262	
13.2	38	199.21	2496	10159	9950	15.84	200.3	414	
13.2	38	248.19	3659	10464	10136	16.44	250.1	600	
13.2	76	0.95	0	9550	9551	14.61	0-1.50	0	Temp: 100 deg F
13.2	76	1.79	0	9538	9539	14.56	0	0	Temp: 123 deg F
13.2	76	50.09	330	9663	9652	14.75	49.08	101	Temp: 100 deg F
13.2	76	100.03	956	9811	9760	14.92	101.2	209	Temp: 100 deg F
13.2	76	149.67	1829	9995	9879	15.21	150.5	340	Temp: 123 deg F
13.2	76	198.95	2978	10265	10057	15.93	200.57	518	Temp: 123 deg F
13.2	76	247.73	4379	10619	10294	16.55	250.5	755	Temp: 123 deg F

Table 3.2: Comparison of AFP from UbitTS™ and LSU calculations

Viscosity	Flow-out (gpm)	UbitTS™ AFP (psi)	Calculated AFP (psi)
38 cp	50	53	96
38 cp	101	134	192
38 cp	150	262	289
38 cp	200	414	570
38 cp	250	600	886
76 cp	49	101	192
76 cp	101	209	384
76 cp	151	340	577
76 cp	201	518	769
76 cp	251	755	961

From Table 3.2, we noticed that the friction factor in the simulation results appeared consistently low for all flow rates as compared to manual calculations based on initial fluid rheologies. A linear trend between 'AFP' and viscosity and 'AFP' and flow rate was observed only at a very low flow rate (50 to 100 gpm) suggesting earlier transition to turbulent flow than calculated manually based on a Reynolds number of 2100. The developer of the simulator Scandpower Petroleum Technology has been notified of this discrepancy.

The sensitivity of the shut in response time to different sizes of gas kicks was also considered. The results are provided in table 3.3. Figure 3.2 shows a plot of the initial kick volume versus the time after shut-in for the formation influx to stop.

Table 3.3: UbitTS^{TM} simulation results for shut-in response

Kick Size	Gas Kick Vol (bbl)	Time to stop kick (min)	Initial Condition (at well shut-in time)			Final Condition (when formation influx stopped)	
			Annular Pressure (psi)	Surface Pressure (psi)	Influx Rate (lb/s)	Annular Pressure (psi)	Surface Pressure (psi)
Small	6.34	12	9626.19	14.82	2.31	9902.58	342.01
Medium	14.4	8.34	9545.10	14.73	2.99	9902.71	405.06
Large1	18.97	5.2	9509.57	14.73	3.3	9900.2	452.25
Large2	23.25	4	9468.97	14.74	3.62	9900.68	500.82
Large3	28.68	3.3	9410.64	14.75	4.14	9901.84	563.39

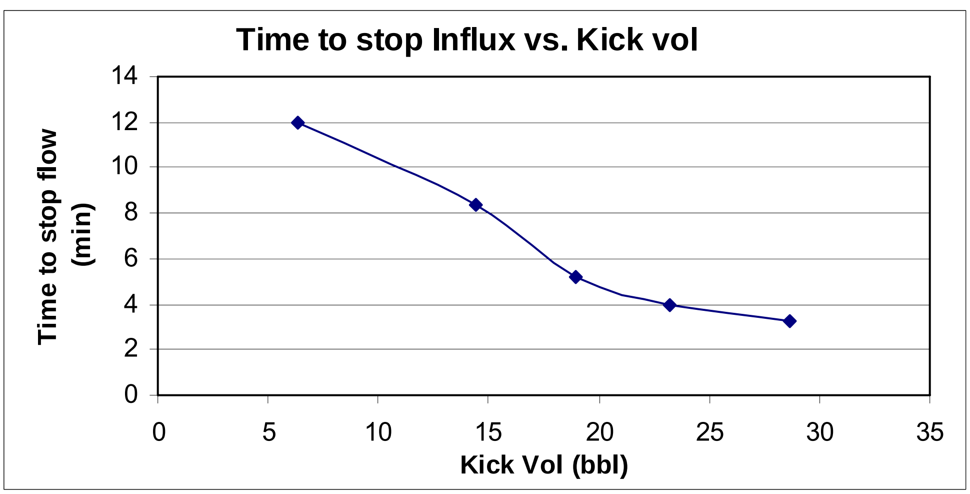

Figure 3.2: Time to stop influx versus kick volume

It may be seen that the 'time to stop the influx' was inversely proportional to the kick size as opposed to the expectation that it would be proportional due to the larger compressibility of larger kicks. In view of the complexity of transient multiphase flow during gas migration in a closed well, the question arises whether such results of simulations are valid. The resolution of this issue is currently the subject of consultation with the developer of the simulator.

3.3.1.3 Simulator Input

The various input to the simulator includes drill string and casing data, cement tops, water depth and deviation data in order to define the geometry of the well and surface and bottom hole temperature, pore pressure, fracture pressure, formation gas oil ratio (GOR), percentage water cut, type of reservoir fluid, productivity index (PI), injectivity index, and formation hardness in order to characterize the reservoir and other open hole formations. Various operational parameters such as mud weight, mud viscosity, pump capacity, mud tank capacities, mud type, RCH pressure limit, maximum choke size, return line diameter and length are also specified as input data for running simulations.

3.3.1.4 Simulation Method

Drilling is simulated in the well with an initial bit depth above the reservoir after entering all input data for an individual well control case. As drilling advances through the reservoir rock, the well becomes underbalanced, and the kick fluid enters the wellbore. In these simulation studies, kicks are identified by observing the increase in return mud flow rate. After a kick is identified, more kick fluid can be allowed to enter the wellbore in order to take a kick of pre-determined volume to simulate the range of kick detection and reaction times that might be achieved in practice in the field before taking action to stop the inflow. Thereafter, interactive controls are used to try out one of the different initial responses proposed to stop the formation fluid influx into the wellbore. The simulation results can then be compared as a basis for evaluating the different initial responses.

4. INITIAL RESPONSE TO KICK

4.1 Introduction

The proper initial response to a kick is very important for successful well control operation. Early kick detection and a proper initial response are needed to keep the initial kick size small. When kick is taken, achieving the smallest possible kick size is important because a larger kick will result in higher wellbore and casing pressures implying increased risk of lost returns or of a surface equipment failure. A larger volume of kick fluid to handle at the surface also increases the risk of a surface equipment failure or overflow. In addition, the ability to diagnose problems during the initial response e.g. the ability to identify lost returns or determine the incremental mud weight needed for primary well control as referred in section 3.2, are important considerations.

The procedure for initial kick response in conventional drilling is well established. It involves shutting-in the well after a positive flow check is recorded. This is followed by recording the shut-in drill pipe pressure, the shut-in casing pressure and the pit gain versus time.

However, in the CBHP method of MPD operation, the annulus is always closed at the RCH creating a closed circulation system. Therefore, there are several other options for initial responses to a kick. The various options for initial kick response are discussed below.

4.2 Shut-in the Well

Shutting in the well is the established initial response to a kick taken during conventional drilling[42]. One advantage of this method is that the mud weight required for primary well control can be calculated from the recorded shut-in drill pipe pressure data.

However, if a drill pipe float is used, which is normally the case in MPD, determining shut-in drill pipe pressure is difficult. The pressure to bump the float by pumping slowly and recording the pressure when the float appears to open is used as an estimate of shut-in drillpipe pressure. Another advantage is that stopping the flow of all fluids to the surface conclusively prevents formation fluid flow to the surface, at least initially. For this option, the annulus may be closed with either the BOP or the RCH for pressure containment.

4.3 Apply Back Pressure Through Choke

Increasing the back pressure applied to the well by adjusting the choke is another option. After a kick is identified by a noticeable increase in return mud flow rate, circulation is continued while back pressure is applied through the choke until the return mud flow rate becomes equal to the pumping rate, which would normally suggest the stoppage of formation fluid influx into the wellbore. At this point, the drillpipe pressure is read and used as the basis for further pressure control. In this type of initial response, pore pressure can not be calculated as directly as in case of the shut-in option. Nevertheless, the increase in drillpipe pressure is the pressure increase needed to balance the pore pressure. The magnitude of back pressure is limited by the maximum allowable casing pressure before formation breakdown, but the magnitude required is reduced by the AFP in the well.

4.4 Increase Pump Rate

Increasing pump rate after the kick is detected to increase the frictional pressure losses in the wellbore and the bottom hole pressure is another option. If the bottom hole pressure can be increased enough to equal or exceed the pore pressure, the formation fluid influx into the wellbore will be stopped, indicated by return mud flow rate equal to the mud flow rate-in. However, to a large extent, frictional pressure losses in the wellbore will depend on the annular clearance. A narrower clearance between the wellbore and the drillstring causes higher annular frictional pressure losses. In a slim hole geometry, this type of initial response may be effective provided mud pump capacity is not exceeded. In a big size hole with large annular clearance, this type of initial response is unlikely to be very effective.

4.5 Increase Pump Rate and Increase Back Pressure

The pump rate may also be increased simultaneously with application of back pressure by adjusting the choke to cause a more rapid increase of bottom hole pressure to stop the influx after the kick is detected. The combined approach may be desirable when either action alone is not sufficient to increase the bottom hole pressure to equalize the pore pressure.

4.6 Additional Considerations

Normally, drilling will be discontinued after a kick is identified and before application of any of these initial reactions to a kick. After stopping the influx by equalizing the bottom hole pressure with the pore pressure, the kick fluid is expected to be circulated out maintaining a constant BHP, and thereafter drilling resumed. However, another possible option is to keep drilling while the drilling choke and / or mud pump is manipulated to increase the bottomhole pressure to stop the influx. This option has conceptual advantages of eliminating non-drilling time associated with kick control and taking advantage of the density added by cuttings in the annulus.

There are several concerns with this approach. The increasing flow rate from additional penetration of the kick zone will result in a larger kick and may delay stoppage of formation feed-in. The routine strategy of keeping stand pipe pressure constant while circulating will not maintain a constant BHP opposite the kick zone as in the driller's method[41] of kick circulation due to the increase in frictional pressure with increasing depth. One safety concern is that the better pressure containment offered by the BOP can not be used unless drilling is stopped.

Another complication is that if the mud pump is running close to its pressure limit, the mud flow rate must be reduced while applying back pressure through choke during initial reaction to kick to avoid tripping of the relief valve.

4.7 Options Investigated

Only the shut-in, apply back pressure, and increase pump rate options will be considered in this study. The other options are adaptations or combinations of these and will be considered for future investigations.

5. SIMULATION OF REPRESENTATIVE WELL -X

5.1 Back Ground of Well Design

A sponsor provided a well description that was selected as representative of slim hole applications for MPD. This description was used as a basis for simulations to investigate alternative initial responses to kicks taken while conducting MPD in a slim hole. The well is planned to be drilled from an offshore platform in about 3000 feet water depth. The objective of this well is to produce from a gas condensate reservoir after sidetracking from 7” casing of an existing well. The sidetrack is to be drilled using MPD methods.

The main reason for MPD in this well is the desire to minimize overbalance opposite depleted zones in order to avoid lost returns or differential sticking. A high wellbore frictional pressure drop due to the slim hole geometry complicates this objective. The highest pore pressure gradient expected in this well is 13.6 ppge (pore pressure = 9901 psi) from a possible gas sand at 15632 ft measured depth, total vertical depth (TVD) 14000 ft, and therefore a minimum mud weight of 13.6 ppg (without considering trip margin) is required to ensure primary control of the well. However, at this mud weight, due to the high frictional pressure losses in the tight annulus, formation breakdown would possibly occur in the depleted zones below this sand during drilling. Therefore, a mud weight lower than 13.6 ppg is needed while drilling to provide an equivalent mud weight slightly more than 13.6 ppg to just over-balance the formation pressure.

During pipe connections, when there is no frictional pressure in the wellbore, the plan is to apply back pressure with a choke to maintain wellbore pressure greater than the pore pressure to avoid formation fluid influx. Also, this will help to maintain a stable wellbore with a constant bottomhole pressure. Table 5.1 provides the relevant well data, and the well schematic, plots of inclination versus measured depth (MD), horizontal drift (HD) versus TVD and PP-FP profiles are shown in Figure 5.1, Figure 5.2, Figure 5.3 and Figure 5.4 respectively

Table 5.1: Summary data of well-X

WELL SUMMARY	
Well Name	Well X
Vertical / Inclined	Inclined
Type of Well	Re-Entry Sidetrack
Offshore / Onshore	Offshore
Water Depth	~ 3000 ft
KB	170 ft
TD (MD / TVD)	19000 / 15000 ft
Objective	Produce from Deeper Sand
Reservoir Fluid	Gas Condensate
CGR	250 bbl / MMSCF
Mud Type	SBM
Bottom Hole Temp	165 degree F

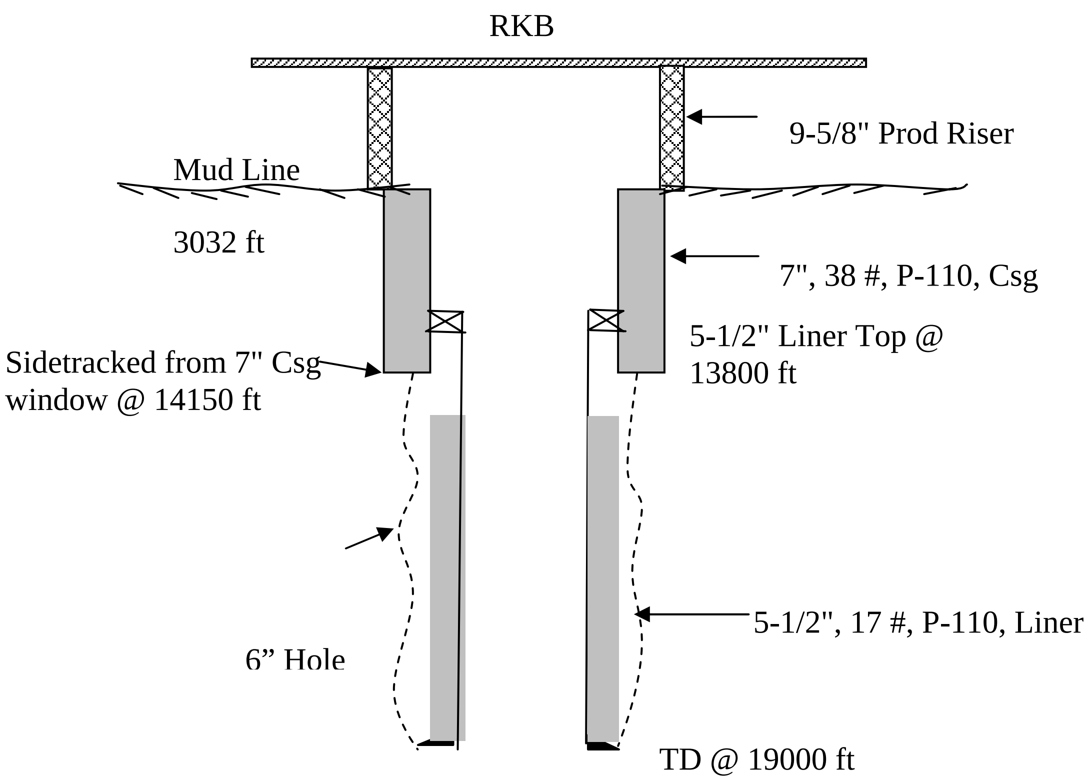

Figure 5.1: Well-X sidetrack schematic

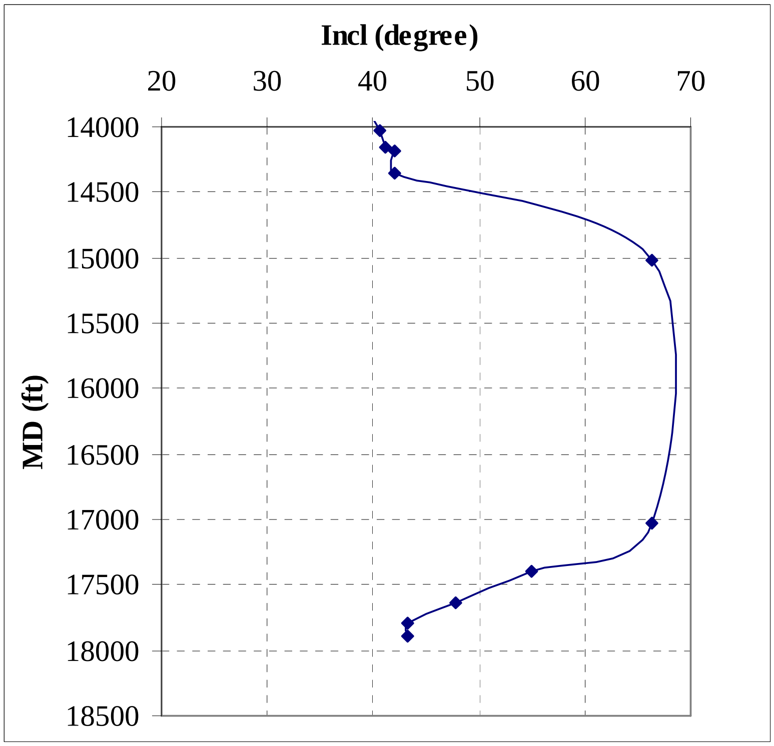

Figure 5.2: Well-X inclination versus MD

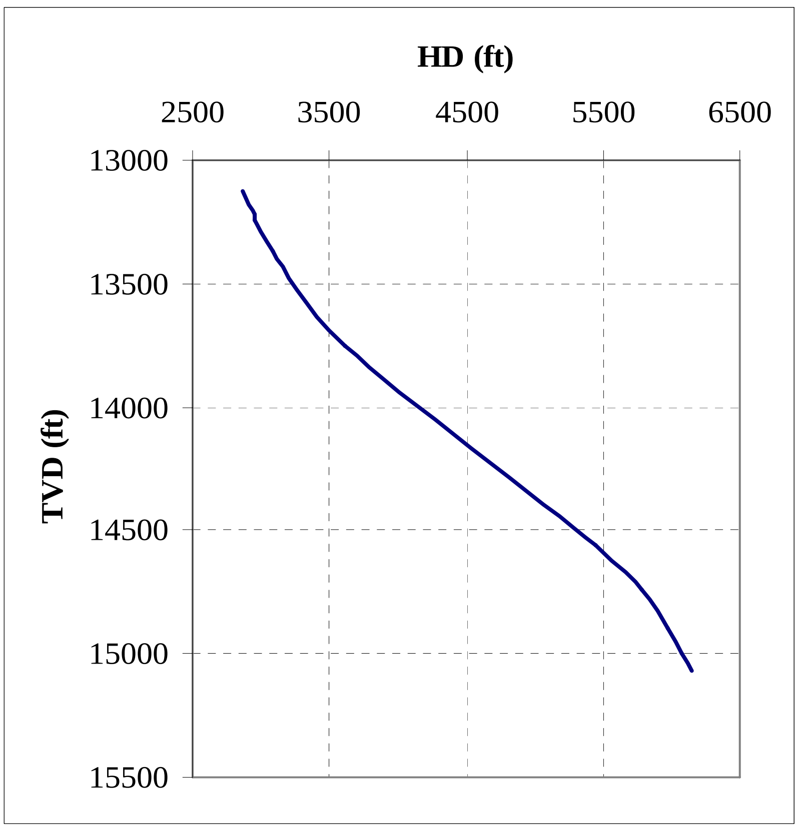

Figure 5.3: Well-X HD versus TVD

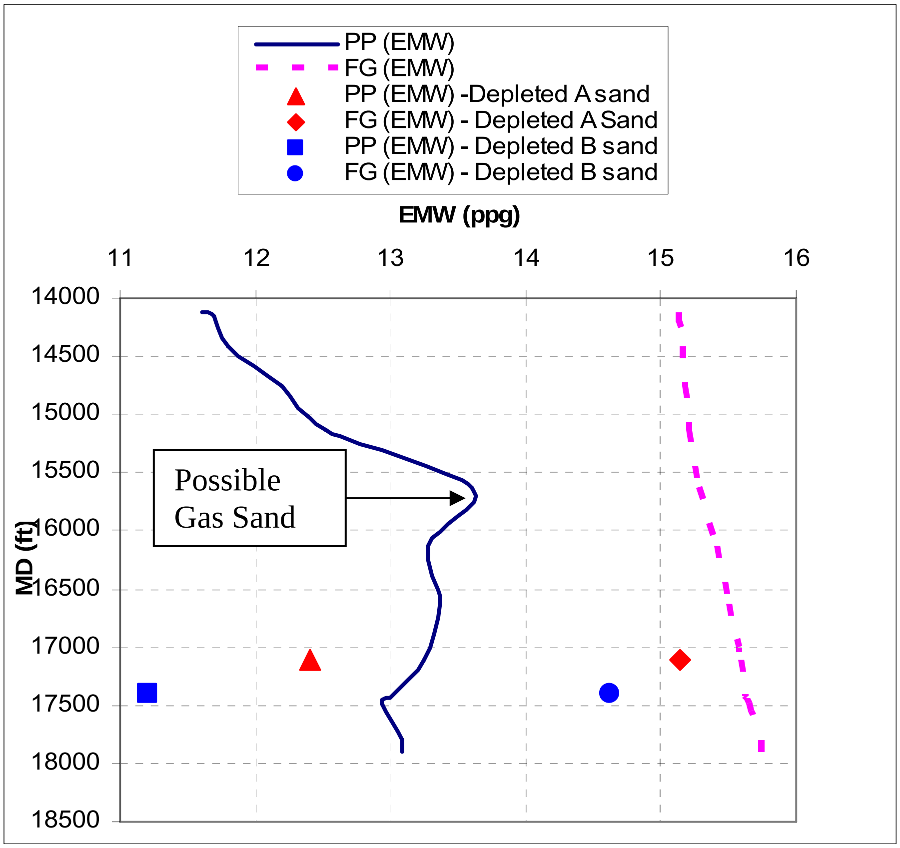

Figure 5.4: Well-X PP-FP profiles

There is risk of lost returns in the depleted B sand below the gas sand shown in Figure 5.4. The high ECD due to the slim hole, low FP at 17400 ft in the depleted zone, and uncertainty in PP at 15632 ft represent a formidable drilling challenge requiring precise wellbore pressure management.

5.2 Descriptions of Simulations

Three different initial responses, namely 'shut-in the well', 'apply back pressure' and 'increase of pump rate' were simulated for a range of possible well conditions to compare the results of the different initial responses. An overall summary of the reaction options and the controlling well conditions that were simulated in this study are presented in Table 5.2. A total of 36 simulations involving kicks while drilling into the over-pressured sand at 15632 ft in this slim hole sidetrack were undertaken. Varying kick sizes, type of drilling mud (water-based or oil-based), type of reservoir fluid (gas or oil) were considered for these simulations

The drilling operations were simulated for all cases with weight on bit (WOB): 20,000 lbf and rotary speed: 100 rpm. The WOB was chosen according to the available buoyed weight of the BHA. The rotary speed was chosen within the standard range normally used in rotary drilling. The pump rate was kept low, 150 gpm; for most cases due to high frictional pressure losses in the slim hole geometry.

A batch of 5 simulations, labeled 1M, were run where kicks were induced in the well from the high pressure gas sand while drilling through a deeper weak formation with partial losses. A higher flow rate, 225 gpm, was used in these simulations, so that the high pressure upper sand can be drilled through with a slight overbalance before penetrating the weak formation.

A final simulation, S/No 42 was run to observe the system behavior when the increase back pressure response was taken to a false alarm.

All simulations were conducted with a drilling mud represented with a Newtonian fluid rheological model.

In general, three different options of initial responses were simulated for the same input data. Simulating each alternative initial response required only different run-time control inputs to the simulator.

5.3 Simulations of Sub Group-1A, 1B and 1C

A total of 9 simulations in three batches with three different kick sizes were run in these simulations to compare the effectiveness of three different initial reactions to a gas kick in water-based mud.

Table 5.2: Well-X simulation cases

Sub Group	S/No	Case No	Initial Kick response	Mud weight	Reservoir Fluid	Kick Intensity		Productivity Index (MMSCF/day-psi) / (STB/day-psi)	Kick Volume (bbl)			Type of Mud
						Static	Dynamic		High	Medium	Low	
1A	1	Case 1	Shut-in Well	13.2	Gas	0.4 ppg	68 psi	0.4286			0.64	WBM
	2	Case 2	Apply Back Pressure	13.2	Gas	0.4 ppg	68 psi	0.4286			0.72	WBM
	3	Case 3	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	68 psi	0.4286			0.76	WBM
1B	4	Case 4	Shut-in Well	13.2	Gas	0.4 ppg	68 psi	0.4286	16.4			WBM
	5	Case 5	Apply Back Pressure	13.2	Gas	0.4 ppg	68 psi	0.4286	16.35			WBM
	6	Case 6	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	68 psi	0.4286	16.35			WBM
1C	7	Case 7	Shut-in Well	13.2	Gas	0.4 ppg	68 psi	0.4286		4.83		WBM
	8	Case 8	Apply Back Pressure	13.2	Gas	0.4 ppg	68 psi	0.4286		4.89		WBM
	9	Case 9	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	68 psi	0.4286		4.89		WBM
1D	10	case 1A	Shut-in Well	13.2	Oil	0.4 ppg	68 psi	87	15.49			WBM
	11	case 2A	Apply Back Pressure	13.2	Oil	0.4 ppg	68 psi	87	15.35			WBM
	12	case 3A	Increase Mud Flow Rate	13.2	Oil	0.4 ppg	68 psi	87	15.35			WBM
1E	13	case 4A	Shut-in Well	13.2	Oil	0.4 ppg	68 psi	87		5.71		WBM
	14	case 5A	Apply Back Pressure	13.2	Oil	0.4 ppg	68 psi	87		5.84		WBM
	15	case 6A	Increase Mud Flow Rate	13.2	Oil	0.4 ppg	68 psi	87		5.84		WBM
1F	16	case 7A	Shut-in Well	13.2	Oil	0.4 ppg	68 psi	87			0.96	WBM
	17	case 8A	Apply Back Pressure	13.2	Oil	0.4 ppg	68 psi	87			1.03	WBM
	18	case 9A	Increase Mud Flow Rate	13.2	Oil	0.4 ppg	68 psi	87			1.03	WBM
1G	19	case 1B	Shut-in Well	13.2	Gas	0.4 ppg	110 psi	0.4286	16.18			OBM
	20	case 2B	Apply Back Pressure	13.2	Gas	0.4 ppg	110 psi	0.4286	15.98			OBM
	21	case 3B	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	110 psi	0.4286	15.71			OBM
1H	22	case 4B	Shut-in Well	13.2	Gas	0.4 ppg	110 psi	0.4286		6.5		OBM
	23	case 5B	Apply Back Pressure	13.2	Gas	0.4 ppg	110 psi	0.4286		6.38		OBM
	24	case 6B	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	110 psi	0.4286		6.27		OBM
1I	25	case 7B	Shut-in Well	13.2	Gas	0.4 ppg	110 psi	0.4286			1.02	OBM
	26	case 8B	Apply Back Pressure	13.2	Gas	0.4 ppg	110 psi	0.4286			1.12	OBM
	27	case 9B	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	110 psi	0.4286			1.13	OBM

Table 5.2 Cont.

1J	28	case 1C	Shut-in Well	13.2	Oil	0.4 ppg	110 psi	0.4286	15.55			OBM
	29	case 2C	Apply Back Pressure	13.2	Oil	0.4 ppg	110 psi	0.4286	15.74			OBM
	30	case 3C	Increase Mud Flow Rate	13.2	Oil	0.4 ppg	110 psi	0.4286	16.24			OBM
1K	31	case 4C	Shut-in Well	13.2	Oil	0.4 ppg	110 psi	0.4286		7.5		OBM
	32	case 5C	Apply Back Pressure	13.2	Oil	0.4 ppg	110 psi	0.4286		7.31		OBM
	33	case 6C	Increase Mud Flow Rate	13.2	Oil	0.4 ppg	110 psi	0.4286		7.47		OBM
1L	34	case 7C	Shut-in Well	13.2	Oil	0.4 ppg	110 psi	0.4286			1.36	OBM
	35	case 8C	Apply Back Pressure	13.2	Oil	0.4 ppg	110 psi	0.4286			1.51	OBM
	36	case 9C	Increase Mud Flow Rate	13.2	Oil	0.4 ppg	110 psi	0.4286			1.49	OBM
1M	37	case 1D	Apply Back Pressure	13.2	Gas	0.4 ppg	-	0.4286		10		WBM
	38	case 1D-Altternate-1	Apply Back Pressure	13.2	Gas	0.4 ppg	-	0.4286		10		WBM
		In this simulation the return flow rate was forced to equal the pumping rate until the end of simulation										
	39	case 1D-Altternate-2	Apply Back Pressure	13.2	Gas	0.4 ppg	-	0.4286		10		WBM
		In this simulation the return flow rate was forced to equal the pumping rate for about 23 minutes, and thereafter, attempted to maintain the drillpipe pressure constant by choke adjustments										
	40	case 2D-	Shut-in Well	13.2	Gas	0.4 ppg	-	0.4286		10		WBM
	41	case 3D	Increase Mud Flow Rate	13.2	Gas	0.4 ppg	-	0.4286		10		WBM
	Remarks: This group of simulations involve kicks from upper sand because of lost returns in a deeper weak formation											
-	42	case 0	Apply Back Pressure	13.2	Response to False Alarm							WBM

The input data for these simulation cases is provided in Appendix: A1. Table 5.3 describes the nomenclature for the various simulations undertaken under these sub-groups. The Table 5.4 summarizes the simulation results of these sub-groups. Note that gains are quantified in pounds because the simulator uses this unit rather than barrels.

Table 5.3: Nomenclature of sub-group 1A, 1B and 1C simulations

Sub Group	Kick Volume (bbl)	Simulation	Option
1A	low (0.64 – 0.76)	Case 1	Shut-in Well
		Case 2	Apply Back Pressure
		Case 3	Increase Mud Flow Rate
1B	high (16.35 – 16.40)	Case 4	Shut-in Well
		Case 5	Apply Back Pressure
		Case 6	Increase Mud Flow Rate
1C	medium (4.83 – 4.89)	Case 7	Shut-in Well
		Case 8	Apply Back Pressure
		Case 9	Increase Mud Flow Rate

Table 5.4: Summary results of group 1A, 1B and 1C simulations

Initial Response to Kick	Gas Kick Volume (bbl)					
	Group 1A		Group 1C		Group 1B	
	0.64-0.76 (low volume)		4.83-4.89(medium Volume)		16.35-16.4 (high volume)	
	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)
Shut-in	114.43	404	53.05	457	101.36	520
Apply Back Pressure	183.45	179	124.00	263	871.45	357
Increase Mud Flow Rate	14.01	56	33.14	52	150.03	54

All three initial reactions were successful in stopping the formation fluid influx. It may be noted that larger the kick volume, the higher the surface pressure for all three options. Also, for each kick volume category, surface pressure is highest for the 'shut-in' option and lowest for the 'increase mud pump rate' option. The mud pump rates were raised to 190 gpm, 200 gpm and 230 gpm to stop the formation fluid influx for 'increase mud pump rate' option for low, medium and high volume kicks respectively. These flow rates were easily achievable, and the increase in drillpipe pressure for higher circulation rate was within the pump pressure limit.

No distinguishable pattern of the amount of additional influx after the initial reaction was noticed. The amount of additional influx will depend on several factors such as the influx feed-in rate at the start of the initial reaction, how quickly the choke was adjusted to increase the surface pressure, and how quickly the mud pump rate was increased to increase the ECD. For example for the 'apply back pressure' option, the choke was manually adjusted in small steps until the flow-out was equal to the flow-in. Similarly for the 'increase flow rate option', the mud pump rate was increased in steps until the flow-out became equal to the flow-in. A human factor is also involved to an extent, especially regarding timing, for manual choke and mud pump operations. On the other hand in the 'shut-in' option, the choke was closed almost instantaneously. Therefore, a true comparison of the effectiveness of different initial reactions in terms of additional gain before the stoppage of influx depends on the timing of manual actions and was not made.

5.4 Simulations of Sub Group-1D, 1E and 1F

The next three batches of simulations were run with oil as the reservoir fluid instead of gas. All other input data including drilling parameters were same. High, medium and low kick volumes were simulated in sub-group 1D, 1E and 1F respectively. In each sub-group, three different initial responses to kick were simulated, and the results were compared. Table 5.5 describes the nomenclature for the various simulations undertaken under these sub-groups. Table 5.6 summarizes the simulation results of these sub-groups. All three initial responses were successful in stopping the formation fluid influx. The advantage of the 'increase flow rate' option is that the surface pressure was minimum, and therefore there was the least chance of formation breakdown during the initial reaction.

Table 5.5: Nomenclature of sub-group 1D, 1E and 1F simulations

Sub Group	Kick Volume (bbl)	Simulation	Option
1D	high (15.35-15.49)	Case 1A	Shut-in Well
		Case 2A	Apply Back Pressure
		Case 3A	Increase Mud Flow Rate
1E	medium (5.71 - 5.84)	Case 4A	Shut-in Well
		Case 5A	Apply Back Pressure
		Case 6A	Increase Mud Flow Rate
1F	low (0.96 - 1.03)	Case 7A	Shut-in Well
		Case 8A	Apply Back Pressure
		Case 9A	Increase Mud Flow Rate

Table 5.6: Summary results of group 1D, 1E and 1F simulations

Initial Response to kick	Oil Kick Volume (bbl)					
	Group 1F 0.96-1.03 (low volume)		Group 1E 5.71-5.84 (medium Volume)		Group 1D 15.35-15.49 (high volume)	
	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)
Shut-in	133.02	379	54.24	408	139.68	438
Apply Back Pressure	58.06	212	171.07	261	903	320
Increase Mud Flow Rate	19.64	54	44.97	40	114.94	55

As expected, the surface pressure was maximum for the shut-in option for all sizes of kicks, and a higher kick volume resulted in a higher surface pressure to stop the influx. The mud pump rates were raised to 180 gpm, 190 gpm and 200 gpm to stop the formation fluid influx for ‘increase mud flow rate’ option for low, medium and high volume kicks respectively.

5.5 Simulations of Sub Group-1G, 1H and 1I

The next three batches of simulations were run with gas as the reservoir fluid and oil-based mud as the drilling fluid. All other input data including drilling parameters were same. In each sub-group, three different initial responses to kick were simulated, and the results were compared. Table 5.7 describes the nomenclature for the various simulations undertaken under these sub-groups. Table 5.8 summarizes the simulation results of these sub-groups.

Table 5.7: Nomenclature of sub-group 1G, 1H and 1I simulations

Sub Group	Kick Volume (bbl)	Simulation	Option
1G	high (15.71-16.18)	Case 1B	Shut-in Well
		Case 2B	Apply Back Pressure
		Case 3B	Increase Mud Flow Rate
1H	medium (6.27 - 6.50)	Case 4B	Shut-in Well
		Case 5B	Apply Back Pressure
		Case 6B	Increase Mud Flow Rate
1I	low (1.02 - 1.13)	Case 7B	Shut-in Well
		Case 8B	Apply Back Pressure
		Case 9B	Increase Mud Flow Rate

Table 5.8: Summary results of group 1G, 1H and 1I simulations

Initial Response to Kick	Gas Kick Volume (bbl)					
	Group 1I		Group 1H		Group 1G	
	1.02 – 1.13 (low volume)		6.27-6.50 (medium Volume)		15.71-16.18 (high volume)	
	Additional Gain after reaction till stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction till stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction till stoppage of influx (lb)	Max Surface Pressure (psi)
Shut-in	65.43	376	43.00	494	51.86	647
Apply Back Pressure	154.50	190	265.08	240	577.56	345
Increase Mud Flow Rate	66.99	35	35.72	54	363.51	55

All three initial reactions were successful in stopping the formation fluid influx. Surface pressures were higher for shut-in options than 'apply back pressure' option for all sizes of kicks, and a higher kick volume resulted in a higher surface pressure to stop the influx.

Compared to water base mud, a rapid increase in return mud flow rate was observed with oil base mud as the high pressure reservoir was penetrated. Although the mud weights were same for both mud types, the frictional pressure losses in the wellbore for oil base mud was less than for the water base mud. For the simulation cases with oil base mud, the bottom hole pressure at the time the kick was taken was 42 psi less than the simulation cases with water base mud, which caused the higher feed-in rate of formation fluid into the wellbore.

The pump rates were raised to 210 gpm, 220 gpm and 270 gpm to stop the formation fluid influx for low, medium and high volume kicks respectively.

Table 5.9 records the 'mud flow rate' required to stop formation fluid influx for the 'increase pump rate' reaction for the group 1A through group 1I simulation runs.

Table 5.9: Mud pump rate for stopping formation fluid influx for group 1A -1I simulations

Kick Fluid	Mud Type	Simulation No	Kick Size		
			Low (gpm)	Medium (gpm)	High (gpm)
Gas	WBM	Case 3	190		
		Case 6			230
		Case 9		200	
Oil	WBM	Case 3A			200
		Case 6A		190	
		Case 9A	180		
Gas	OBM	Case 3B			270
		case 6B		220	
		Case 9B	210		

The data in table 5.9 shows that higher rate was required to stop the formation fluid influx for oil base mud than for water base mud for all three kick sizes. This is understandable as the borehole frictional pressure losses were lower in oil base mud than in water base mud. Also as expected, a higher pump rate was required to stop a larger formation fluid influx.

5.6 Simulations of Sub Group-1J, 1K and 1L

The next three batches of simulations were run with oil as the reservoir fluid and oil base mud as the drilling fluid. All other input data for simulations including drilling parameters were same. In each sub-group, three different initial responses to kick were simulated, and the results were compared. Table 5.10 describes the nomenclature for the various simulations undertaken under these sub-groups.

Table 5.10: Nomenclature of sub-group 1J, 1K and 1L simulations

Sub Group	Kick Volume (bbl)	Simulation	Option
1J	high (15.55-16.24)	Case 1C	Shut-in Well
		Case 2C	Apply Back Pressure
		Case 3C	Increase Mud Flow Rate
1K	medium (7.31 - 7.50)	Case 4C	Shut-in Well
		Case 5C	Apply Back Pressure
		Case 6C	Increase Mud Flow Rate
1L	low (1.36 - 1.51)	Case 7C	Shut-in Well
		Case 8C	Apply Back Pressure
		Case 9C	Increase Mud Flow Rate

Table 5.11 summarizes the simulation results of these sub-groups.

Table 5.11: Summary results of group 1L, 1K and 1J simulations

Initial Response to Kick	Oil Kick Volume (bbl)					
	Group 1L		Group 1K		Group 1J	
	1.36 -1.51 (low volume)		7.31-7.5-(medium Volume)		15.55 – 16.24 (high volume)	
	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)	Additional Gain after reaction until stoppage of influx (lb)	Max Surface Pressure (psi)
Shut-in	137.96	359	119.68	389	71.72	480
Apply Back Pressure	90.92	166	228.99	233	323.64	405
Increase Mud Flow Rate	52.24	54	87.47	60	162.19	59

All three initial reactions were successful in stopping the formation fluid influx. Surface pressures were higher for bigger size kicks for all three options. The maximum surface pressures were recorded for shut in options.

The mud flow rates were raised to 200 gpm, 240 gpm and 260 gpm to stop the formation fluid influx for the ‘increase mud flow rate’ option for low, medium and high volume kicks respectively. The trend is similar to that for gas kicks in oil base mud.

5.7 Discussions on Simulations of Sub Group 1A through 1L

The three initial reactions simulated to stop the influx resulting from gas and oil kicks of varying sizes from a high productivity reservoir in water-based as well as oil-based mud systems were successful in a deep well with a slim hole geometry. In a relatively large window with 15.1 ppge fracture gradient at the weakest formation at the depth of sidetrack and 13.6 ppge pore pressure gradient at the kick zone, the maximum surface pressure did not cause formation breakdown in any of these simulations. However, in a narrow PP-FP window, the surface pressure is a very important factor that will determine the effectiveness of the initial reactions to kick. It has been observed that the surface pressure was maximum in the shut-in option irrespective of kick sizes, types of kick fluid and mud type.

In a slim hole geometry, the ‘increase pump rate’ option has a definite advantage of having the lowest surface pressure because an increased ECD is used to increase the bottomhole pressure to counterbalance the pore pressure.

The additional gain after the initial reaction will impact the surface pressure required to stop the influx for the ‘shut-in’ and the ‘apply back pressure’ options. The impact is generally small if the reaction times are short. Since reaction times for choke adjustment in the ‘apply back pressure’ option, pump speed adjustment in the ‘increase pump rate’ option and closing the choke in the shut-in option are dependent on the individual operator’s actions in a manually controlled system, a comparison of additional gains taken during the initial reactions are not meaningful in this study.

Formation flow was stopped successfully in all of these simulations without losing returns. Therefore, a comparison of the cases from the perspective of identifying whether feed-in was successfully stopped or lost returns have occurred is not possible without conducting additional simulations.

5.8 Simulations of Sub Group-1M

Lost returns in the depleted zone below the high pressure gas sand were a specific concern for the example well. The simulations in Sub Group 1M were set up with a fracture pressure of 10,000 psi, equivalent to 13.54 ppg at a depth of 16130 ft representing the depleted sand. This resulted in a very narrow window between that fracture gradient and the pore pressure of 9901 psi, equivalent to 13.6 ppg in the gas sand. Consequently these simulations present a case with essentially a certainty that either the gas sand will be flowing or losses will be occurring in the zone at 16130 ft or both. These simulations are intended to provide a basis for comparing the effectiveness of different initial responses in this scenario.

The fracture pressure was changed in the input data at 16130 ft. to simulate fracture in the well. The injectivity at 16130 ft was changed to a higher value of 0.4 mmscfd / psi. All other input data for this group of simulations were kept same as the case where gas kicks were simulated before. The well was drilled with 13.2 ppg mud with a higher mud flow rate (225 gpm) compared to the previous simulations so that the high pressure sand could be drilled through with a dynamic overbalance preventing a kick.

The simulation began by drilling the well below the high pressure zone at 15632 ft with dynamic overbalance, until losses were experienced at 16130 ft at about 265 minutes into the simulation, see Figure 5.5. Drilling continued, losses gradually increased, and the return flow rate declined to about 150 gpm versus the pumping rate of 225 gpm at about 320 minutes into the simulation. Thereafter, the return flow rate began increasing, exceeding the pumping rate at about 350 minutes.

Evidence of a kick occurring became stronger as drilling continued to 16287 ft, and a 10 bbl net gain after the flow-out started to exceed the flow-in was used as the starting condition for simulating reactions to this kick. In this case, the kick from the high pressure sand at 15632 ft was triggered by the loss of ECD due to the losses in the weak depleted zone at 16130 ft. The three options for initial reactions to a kick were simulated to control the well, which are described below. Several variations of the ‘apply back pressure’ option were simulated to observe the sensitivity of the results to the specific approach used.

5.8.1 Apply Back Pressure - Case 1D

Back pressure was applied through the choke to reduce the return flow rate gradually to the level of flow rate-in, see Figure 5.5 at about 360 minutes. At that stage, control was switched to maintain the drillpipe pressure constant by adjusting the choke to circulate out the kick maintaining a constant bottomhole pressure. However, the drillpipe pressure continuously declined despite further reduction in the choke opening in an attempt to keep the drillpipe pressure constant. Finally the well was completely closed on choke just before 380 minutes. The simulation was continued for about another 30 minutes to observe the trend of choke pressure and the drillpipe pressure. Figure 5.5 shows that the drillpipe pressure and the choke pressure were nearly constant after the well was closed with continued pumping implying no significant gas migration and total mud losses.

Figure 5.6 and Figure 5.7 show plots of formation fluid flow profile before the back pressure application and at the end of simulation when the choke was completely closed, respectively. From these two plots, it may be seen that there were simultaneous loss and kick in the well before back pressure application. Conversely at the end of simulation, the well was only experiencing lost returns in the fractured zone, and the influx had stopped. Pumping at a constant rate of 225 gpm while holding drillpipe pressure of 2250 – 2300 psi successfully stopped the formation flow, but resulted in total lost returns.

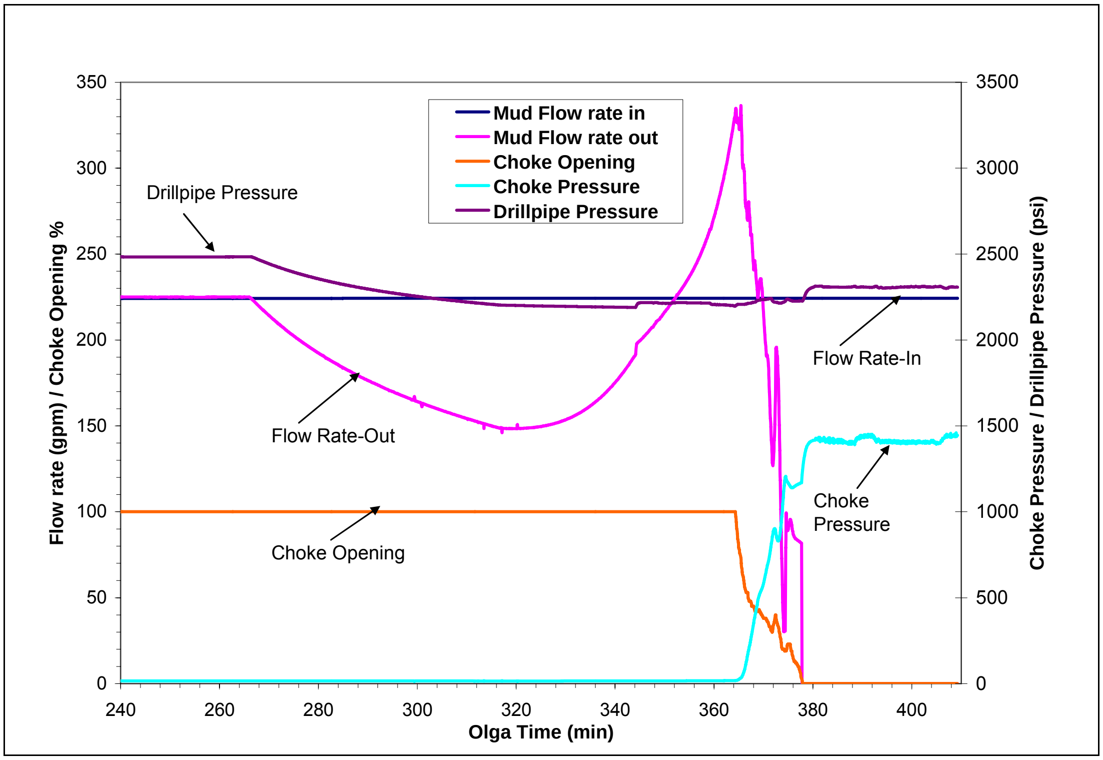

Figure 5.5: Well behavior versus time for well-x, sub-group 1M, case 1D – back pressure

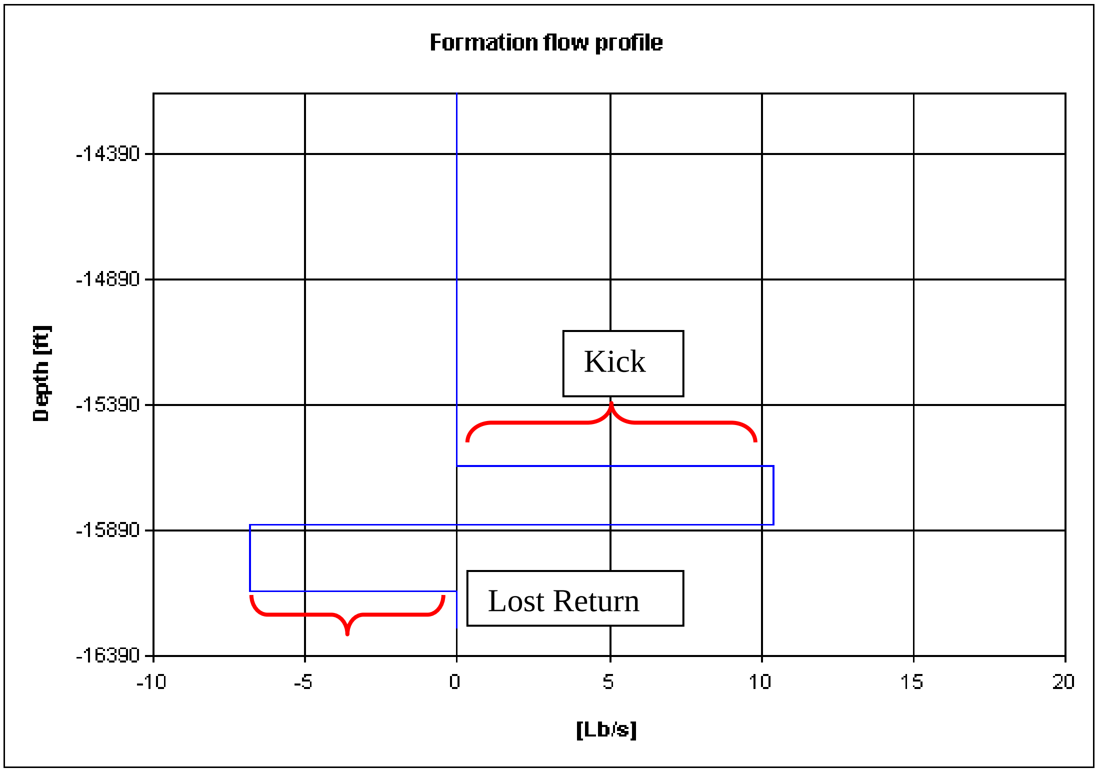

Figure 5.6: Formation flow profile before applying back pressure for well-x, sub-group 1M, case-1D – back pressure

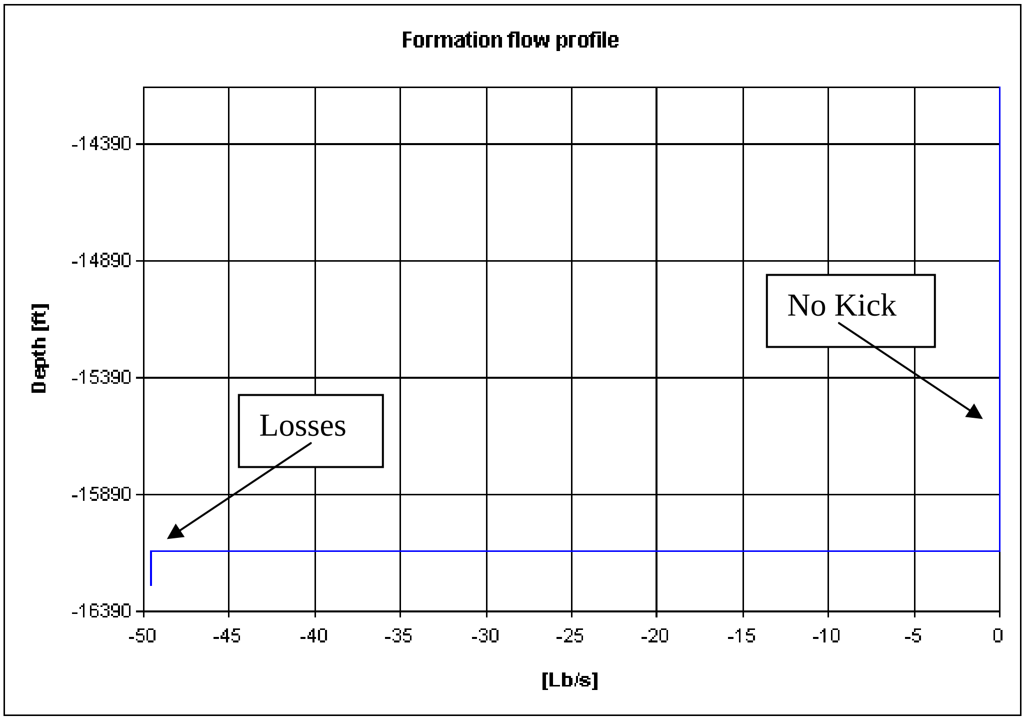

Figure 5.7: Formation flow profile at the end of simulation
for well-x, sub-group 1M, case-1D – back pressure

5.8.1.1 Apply Back Pressure - Case 1D-Alternate-1

A second variation of the 'apply back pressure' response was simulated to determine the effect of forcing flow rate-out to equal flow rate-in for an extended period of time. The choke was adjusted to keep the return flow rate same as the flow rate-in from 350 minutes to the end of the simulation, see Figure 5.8. It may be seen that this resulted in gas flowing to the surface at a progressively higher rate until the end of simulation at about 480 minutes. The well was flowing at 3767 scfm (5.42 mmscfd) at the end of simulation. The choke pressure also continued to increase during this period. The drillpipe pressure gradually declined from about 2250 psi to 2200 psi despite the increase in choke pressure. This approach resulted in a failure to prevent continuous formation flow to the surface despite drillpipe pressure being only 100 psi less than the previous case, however, the losses had ceased.

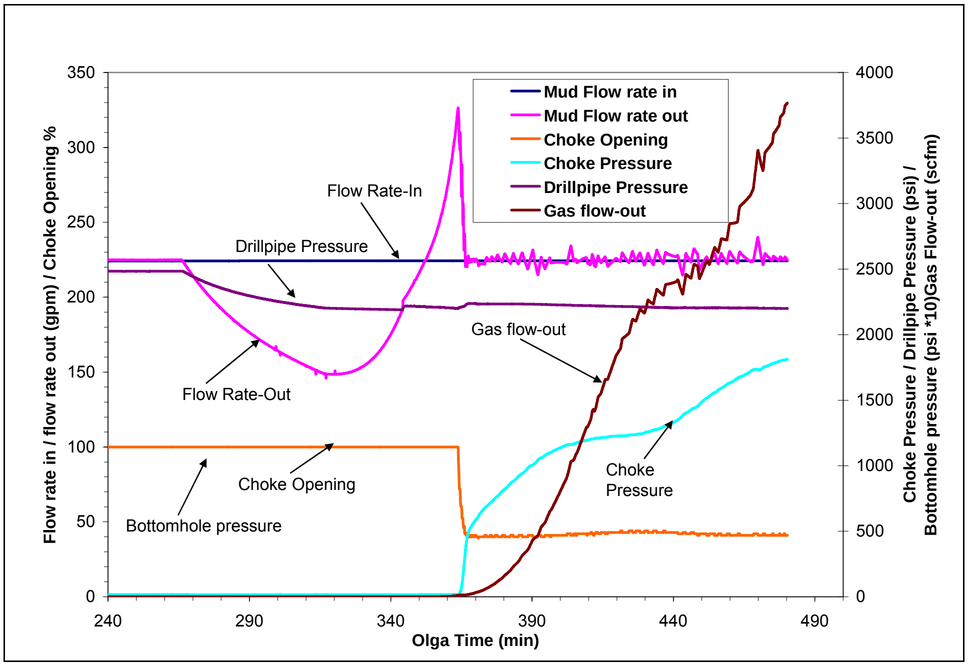

Figure 5.8: Well behavior versus time for well-x,
sub-group 1M, case 1D-Alternate-1 – back pressure

5.8.1.2 Apply Back Pressure - Case 1D-Alternate-2

A third variation of the 'apply back pressure' reaction was simulated to try to more carefully select the drillpipe pressure to maintain constant. All of the input data for this simulation is same as the previous two simulations. The choke was adjusted to maintain the flow-out equal to flow-in for about 23 minutes, and thereafter, the control was switched to maintain the drillpipe pressure constant by choke adjustments. This resulted in maintaining a drillpipe pressure of about 2235 psi, see Figure 5.9. Figure 5.10 shows how more back pressure was applied to check the decline trend of the drillpipe pressure and an increasing rate of gas flowing at surface until about 445 minutes. This induced a higher rate of losses in the fracture. The return flow was reduced to 30 gpm when drillpipe pressure was nearly stabilized. The gas flow rate peaked and then slowly declined. The drillpipe pressure was maintained with little choke adjustment until the end of simulation while loosing returns at a steady rate. The choke pressure gradually decreased as the rate of gas flow reduced.

The simulation was run for prolonged duration until the gas flow rate-out was nearly reduced to zero. Figure 5.9 shows time-based composite plots of drillpipe pressure, choke opening, flow-in and flow-out from 360 to 400 minutes of simulation. Figure 5.10 and Figure 5.11 show the composite plots of drillpipe pressure, choke pressure, choke opening, gas flow out, flow-in and flow-out from 375 to 800 minutes and from 800 minutes to the end of simulation respectively.

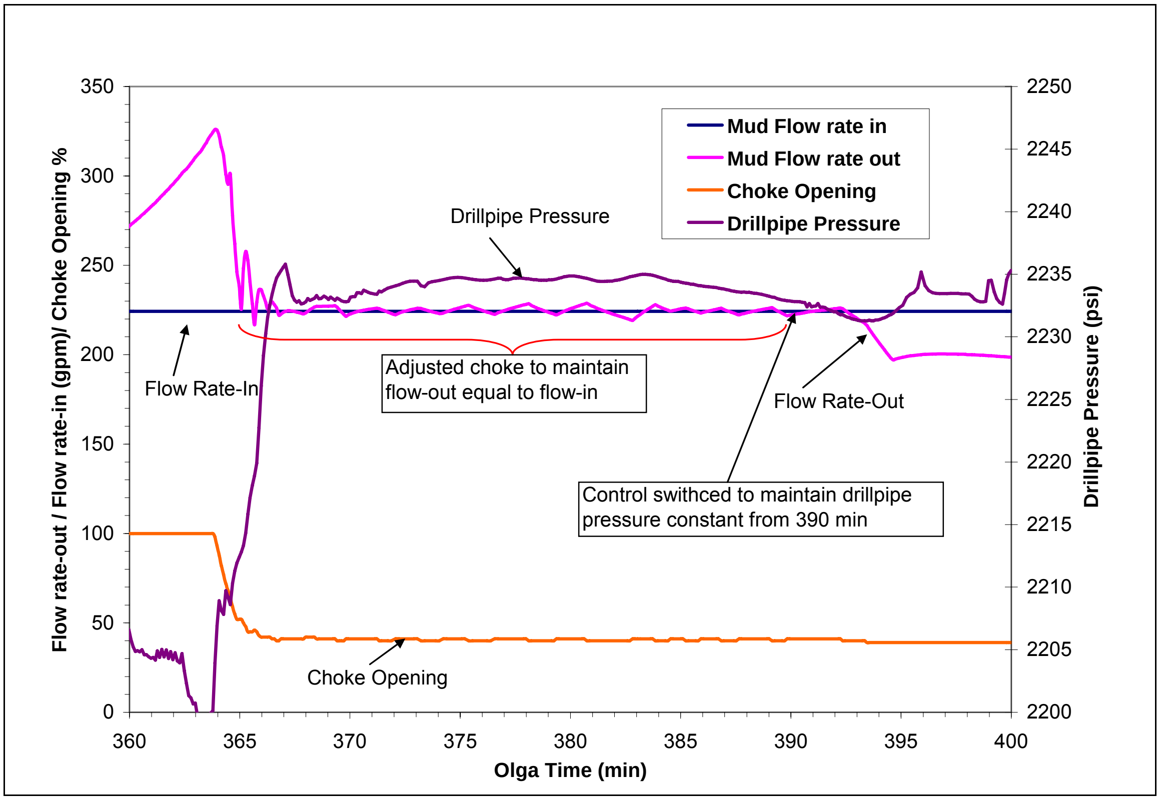

Figure 5.9: Well behavior versus time (360 to 400 minutes)
for well-x, sub-group 1M, case 1D-Alternate-2 – back pressure

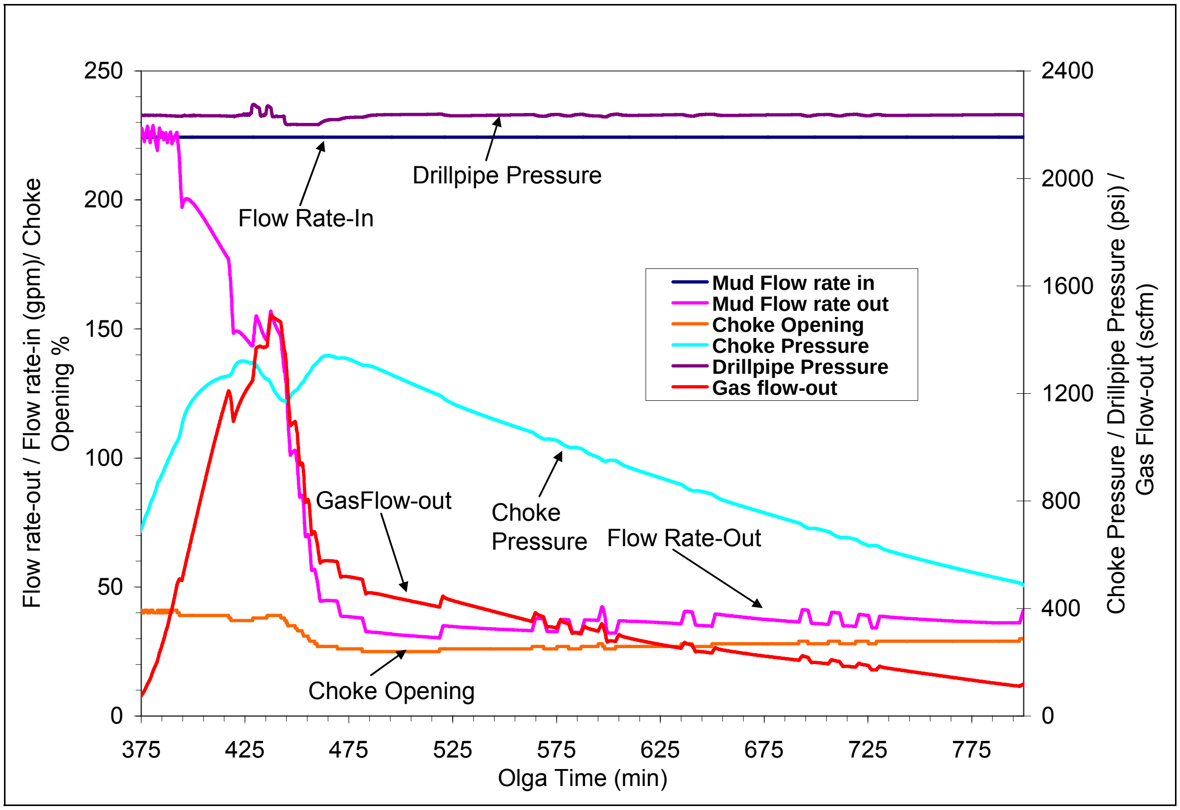

Figure 5.10: Well behavior versus time (375 to 800 minutes) for well-x, sub-group 1M, case 1D-Alternate-2- back pressure

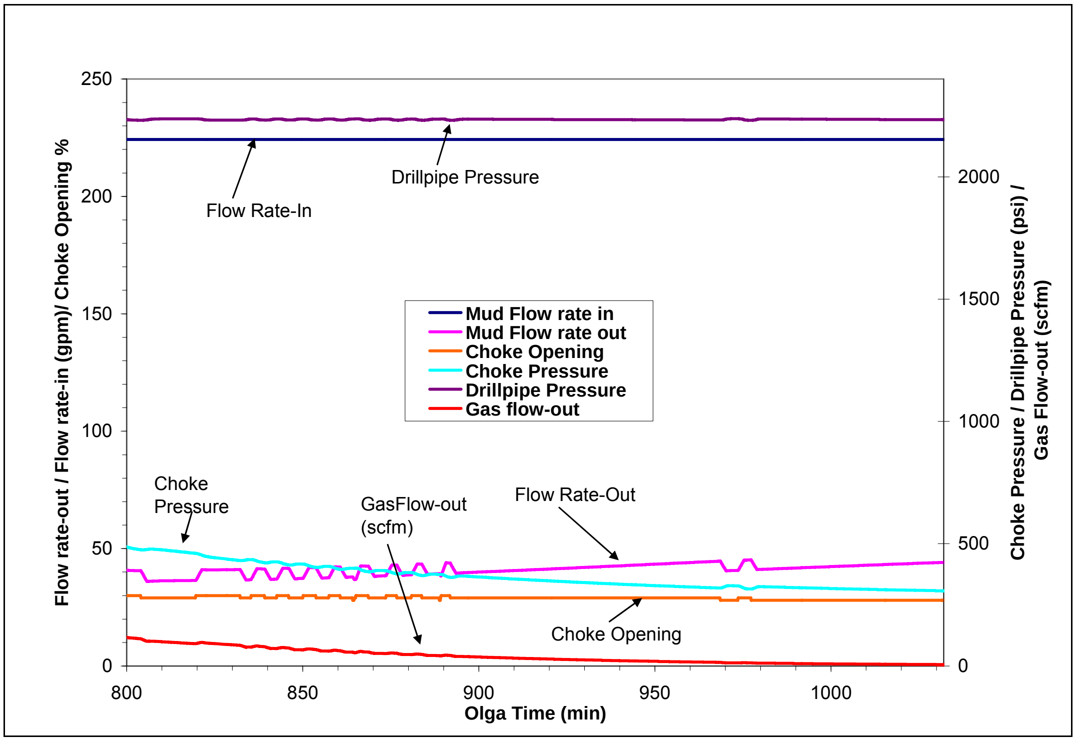

Figure 5.11: Well behavior versus time (800 minutes to the end of simulation) for well-x, sub-group 1M, case 1D-Alternate-2 – back pressure

Figure 5.12 is a time-based plot of choke pressure, drillpipe pressure, bottomhole pressure and gas flow-out from 360 minutes to the end of simulation. It may be seen that the bottomhole pressure was also constant along with a constant drillpipe pressure.

Figure 5.13 shows the liquid holdup profile at the end of simulation. The liquid holdup at the kick zone at the end of simulation is 100 percent implying no influx into the wellbore. The high holdup, greater than 98 percent, indicates that essentially all of the gas has been successfully removed from the well. The low flow rate-out in Figures 5.10 and 5.11 confirm that significant losses are still occurring

These simulations for a kick caused by lost returns in a deeper zone with a fracture pressure only 100 psi more than the kick zone formation pressure demonstrate the difficulty controlling this scenario. Completely successful well control, i.e. stopping formation feed-in and maintaining full returns was not possible. A variation of less than 100 psi in wellbore pressure caused results ranging from essentially uncontrolled gas flow to the surface to complete lost returns.

5.8.2 Shut-in Well - Case 2D

Another potential response that was simulated is shutting the well in. The well was shut-in after taking a 10 bbl kick, and the choke pressure and drillpipe pressure were monitored. In this simulation, the float was removed so that the drillpipe pressure could be monitored. Figure 5.14 is a time-based composite plot of flow rate-in, flow rate-out, choke opening, choke pressure and the drillpipe pressure during the simulation run. It is interesting to note that even without a float, the drillpipe pressure did not respond to the continuous increase in choke pressure that resulted due to gas migration in the closed well.

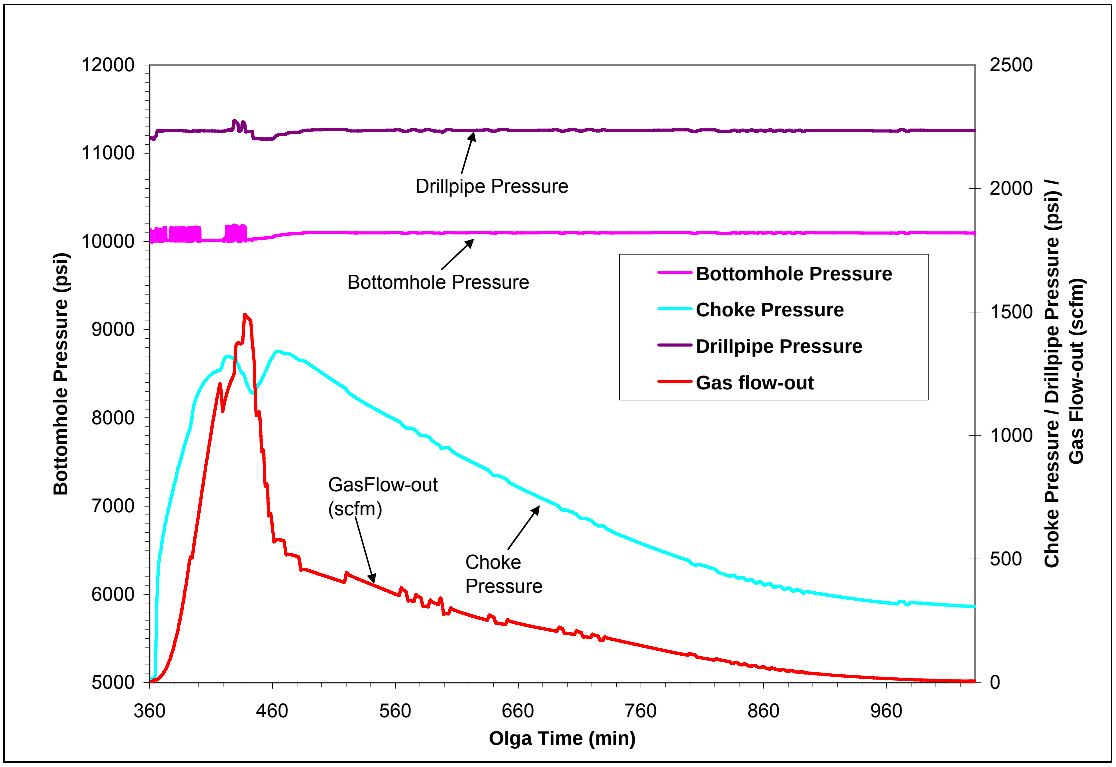

Figure 5.12: Choke, drillpipe and bottomhole pressure versus time from 360 minutes to the end of simulation for well-x, sub-group 1M, case1D-Alternate-2 – back pressure

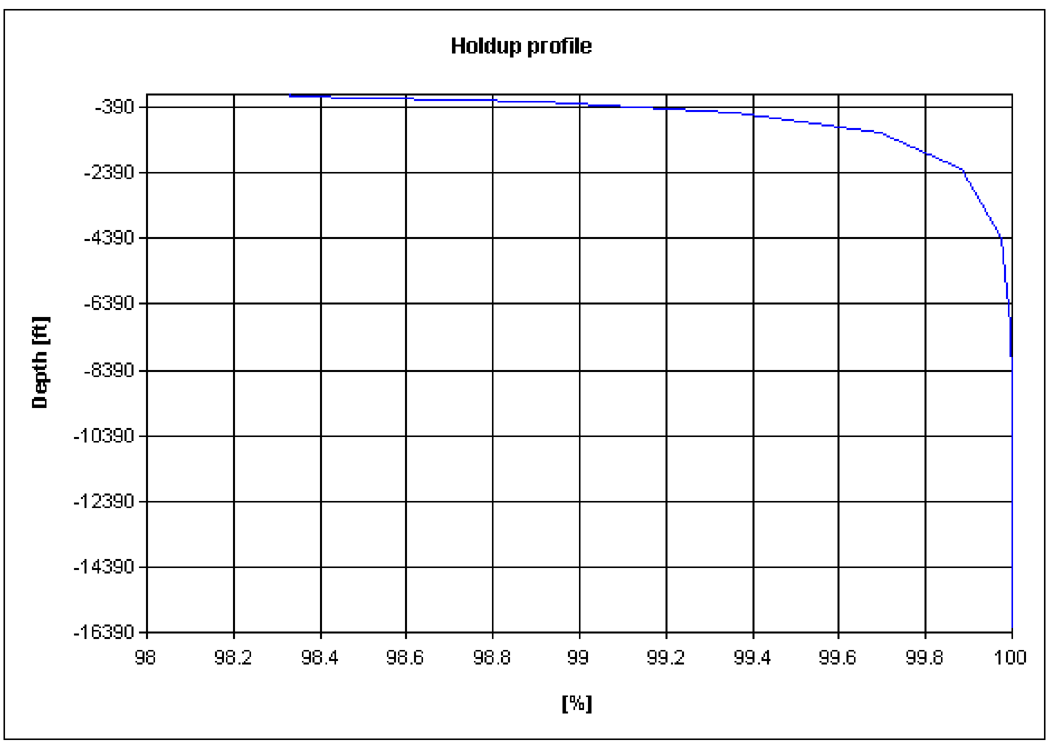

Figure 5.13: Liquid holdup profile at the end of simulation for well-x, sub-group 1M, case 1D-Alternate-2 – back pressure

This could be due to non-intact wellbore with losses below the kick zone, but is not consistent with the bottomhole pressure of 9,900 to 10,000 psi shown in Figure 5.15. This inconsistency has not been resolved. Figure 5.15 shows a time-based composite plot of choke pressure, drillpipe pressure and the bottomhole pressure during the simulation. It may be seen that the choke pressure and the bottomhole pressure were fluctuating after the well was closed. This may suggest a cyclic pattern of gain from the upper kick zone and loss from the lower weak zone in a closed well, experiencing gas migration. However, the short period of these rapid fluctuations is probably more related to the simulation code than to actual well behavior.

Figure 5.16 shows the liquid holdup profile at the end of simulation. The profile suggests that the influx from 15632 ft is continuing as gas is migrating toward the surface. Lost returns in the zone at 16130 ft is probably also occurring, at least intermittently.

5.8.3 Increase Mud Pump Rate - Case 3D

The final response evaluated was increasing the mud pumping rate. The pump rate was increased gradually, after taking a 10 bbl gas kick, to increase the ECD in an attempt to stop the influx. The flow rate-out was monitored against the flow rate-in to identify stoppage of influx. When the pumping rate was increased to 395 gpm, the pump relief valve tripped as the pressure limit was reached. As shown at the end of the simulation in Figure 5.17, the flow-out was then nearly equal to the pumping rate. Because of losses, the pumping rate required to increase ECD to counterbalance the pore pressure is higher in this case than the previous simulations where the wellbores were intact and was never achieved.

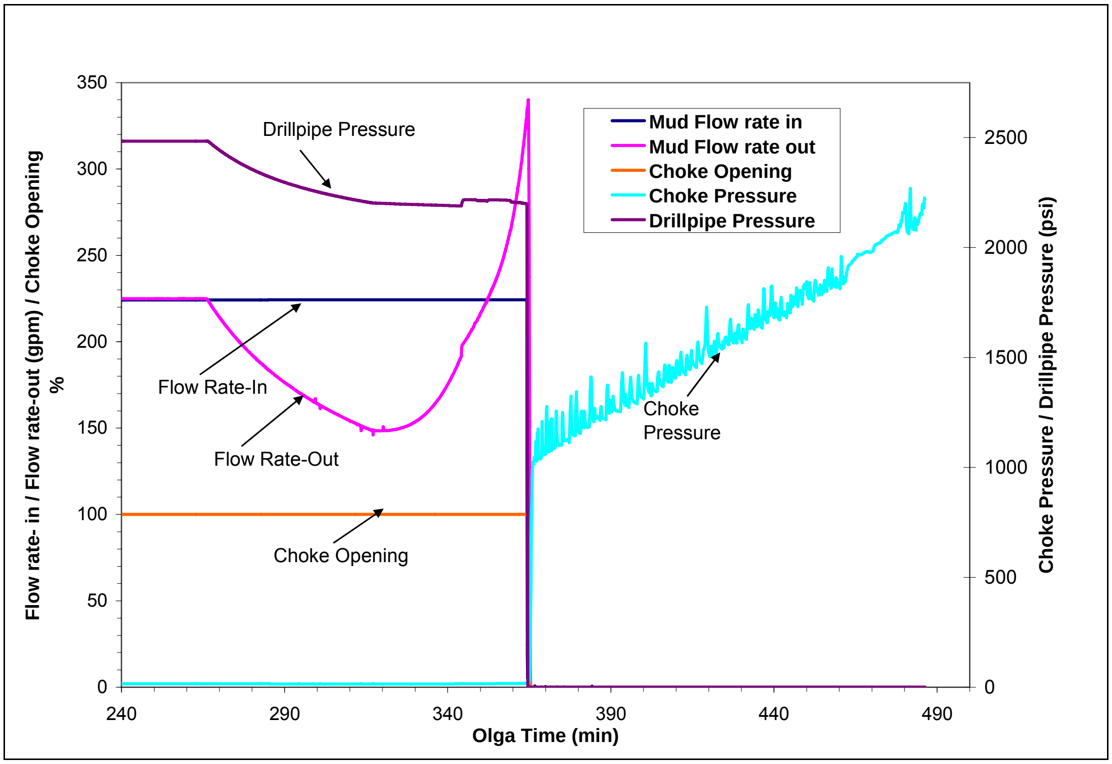

Figure 5.14: Well behavior versus time for well-x, sub-group 1M, case 2D- shut-in

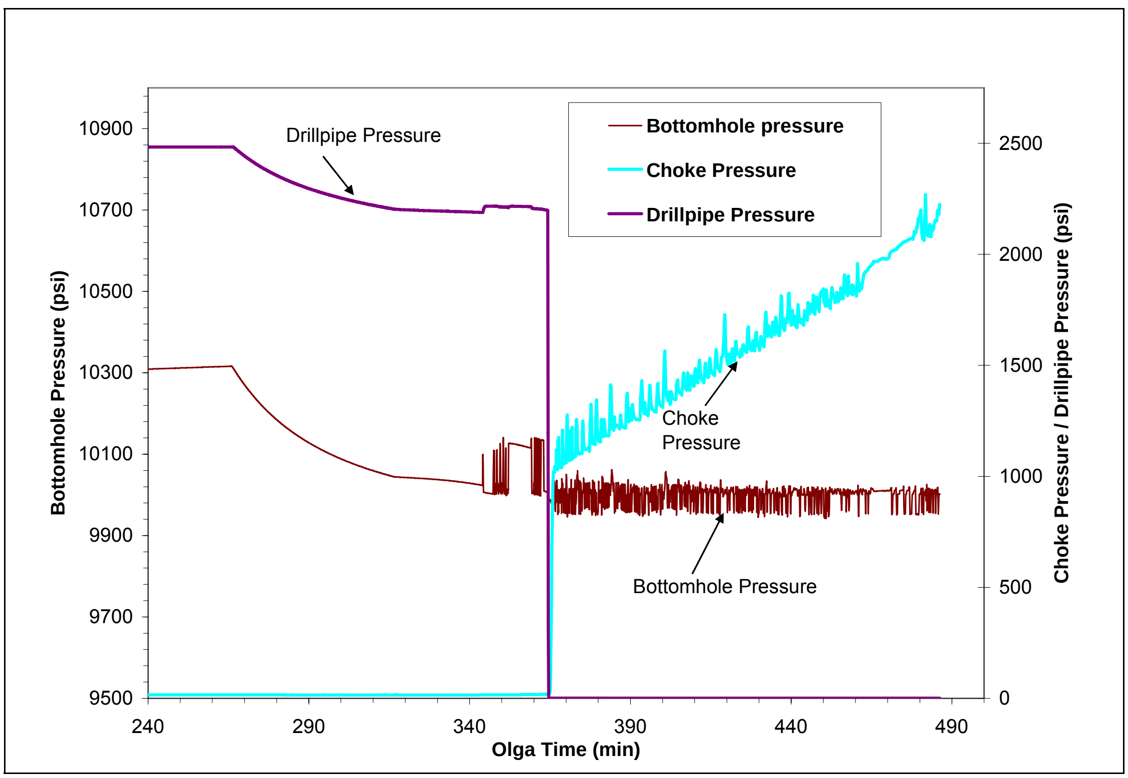

Figure 5.15: Choke pressure, bottomhole pressure and drillpipe pressure versus time of well-x, sub-group 1M, case-2D – shut-in

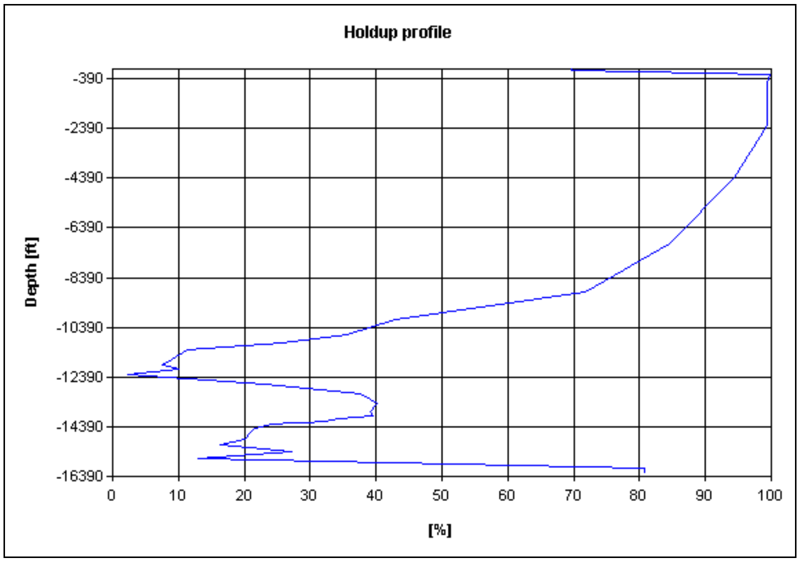

Figure 5.16: Liquid holdup profile at the end of simulation
for well-x, sub-group 1M, Case-2D – shut-in

Figure 5.17 shows the composite time-based plot of flow rate-in, flow rate-out and drillpipe pressure. In this case, in spite of a slim hole geometry with narrow annular clearance, the 'increase flow rate' option to stop the formation influx was not effective because of losses in the wellbore below the kick zone. Figure 5.18 shows the formation fluid flow profile at the end of simulation. It may be seen that both losses and influx were occurring simultaneously, confirming that the increased pump rate was not adequate to stop the influx.

5.8.4 Discussions on Sub Group 1M Simulations

It has been seen that in a narrow PP-FP window, continued drilling with losses into a weak zone may trigger a kick from an upper high pressure zone. While drilling with partial losses, the initiation of a kick from the high pressure zone may not be identified until the return flow rate increases significantly above the pumping rate. In actual drilling, it is likely that a decline in loss rate will be interpreted as bridging or sealing of fractures rather than a threatened kick until the rate or volume of flow back is substantial. Successful well control was not achieved with any of the alternative reactions in this scenario.

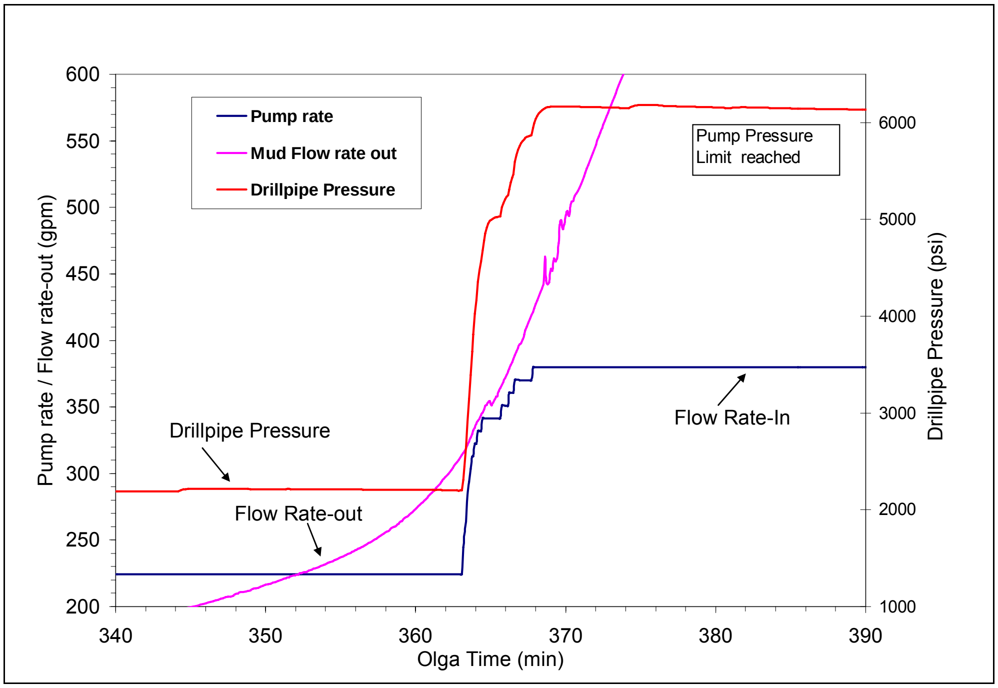

Figure 5.17: Flow rate-in, flow rate-out and drillpipe pressure versus time for well-x, sub-group 1M, case-3D – increase mud flow rate

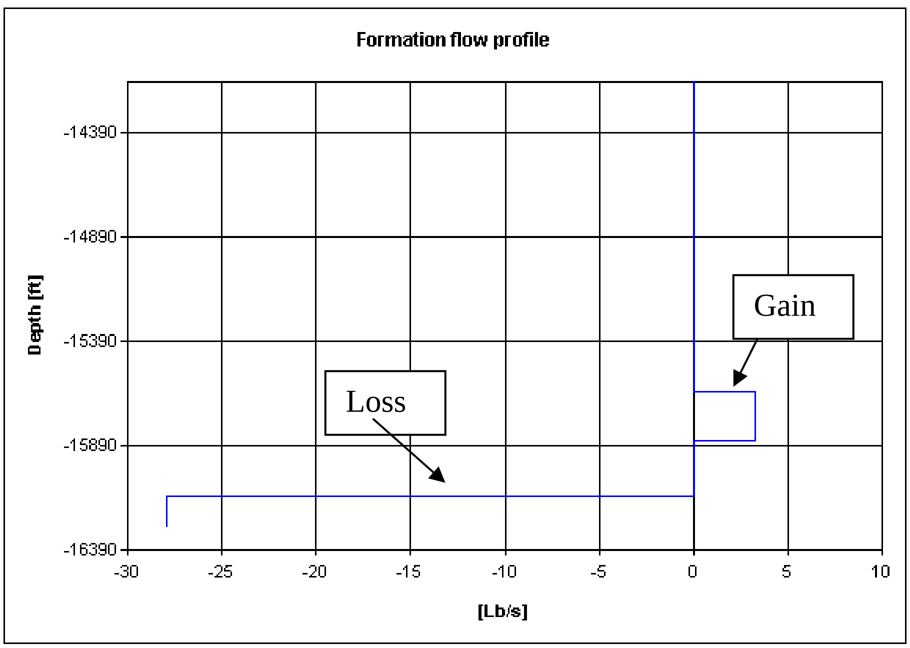

Figure 5.18: Formation fluid flow profile at the end of simulation for well-x, sub-group 1M, case-3D – increase mud flow rate

Increasing mud flow rate to dynamically overbalance the kick zone pressure was not successful as the necessary additional ECD above the kick zone could not be generated. It is unlikely that this approach will be successful in any scenario with significant losses below the kick zone. Logically, however, it might be the preferred option for avoiding losses above the kick zone.

Shutting in the well stopped flow at the surface and the loss of muds from the pits. However, a continuous increase of the choke pressure was observed. Conclusions about whether influx from the formation and downhole losses have stopped are difficult to reach. In the simulation, the formation fluid flow profile suggested that the influx continued. The fluctuation of the choke pressure and the bottomhole pressure after the well was shut-in may be indicative of cyclical loss and gain in the well. In addition, the casing pressure versus time was generally the highest of all the simulated reactions.

The ‘application of back pressure’ to control the well was comprehensively simulated for prolonged periods and with different specific strategies to understand the complex behavior of the well in a simultaneous loss-gain scenario.

Although none of the back pressure reactions effectively controlled the well without lost returns, the cases where the control was switched to maintain the drillpipe pressure constant after the flow-out became equal to the flow-in were able to stop the influx. However, there are multiple complications with this approach. Both variations on this approach required pumping with complete or almost complete lost returns. The difference in drillpipe pressure between cases with no flow to the surface and the case that circulated out the kick was only 50 psi. A clear-cut conclusion that formation feed-in had been stopped was not possible in either case. Specifically, the criteria of flow-out equal to flow-in is neither conclusive nor straight forward to apply to kicks initiated by lost returns. Given that this scenario requires a wellbore pressure at the kick zone almost equal to the fracture pressure in the zone below it, an approach similar to the pressurized mud cap drilling method might be the most appropriate well control approach.

5.9 Simulation of Base Case for Detection of False Alarm – Case 0

A final simulation was run, where the back pressure was applied through the choke, for a case without any noticeable kick in the well. The purpose of this simulation was to establish a baseline well response for comparison to cases with kicks and investigate the ability to identify a false alarm of a kick. The basic input data for this simulation was same as the group 1 simulations. At 15620 ft (12 ft shallower than the kick zone), drilling was discontinued to check whether the well was active or not. The well was circulated for about 5 minutes with only slight changes in flow-out. Thereafter, the choke was gradually closed to increase the bottomhole pressure by increasing the choke pressure as if in response to a kick. The choke pressure was raised to about 100 psi, and thereafter, the choke opening size was held constant at 46 percent for about 5 minutes before ending the simulation. The response of the return flow rate, drillpipe pressure and the choke pressure to the choke adjustments were monitored during the simulation.

Figure 5.19 shows a composite plot of flow rate-in, flow rate-out, choke pressure and choke opening for this simulation. The return flow rate did not increase during drilling or circulation, indicating that that the well was not underbalanced. The overall return flow rate was decreased slightly during the period from 32 to 37 minutes due to fluid compressibility in response to the choke size reduction. However, the return flow rate equalized with the pump rate within three minutes, indicating no lost returns or kick. The choke pressure also stabilized and remained constant when the choke position was held constant implying no gas influx and lost returns.

Figure 5.20 shows the response of the drillpipe pressure and the choke pressure to the choke opening size. It may be seen that the drillpipe pressure had gradually increased with back pressure application from about 31 to 40 minutes and then remained constant like the choke pressure as the choke opening was held constant, showing no indication of an influx or a gas migration effect. The simulator does not provide pit gain as an output, but the only change in pit level should be a slight reduction in the pit volume due to the compressibility of the wellbore fluid. This behavior is as expected, but it does not provide as conclusive a basis for rejecting false alarms as a flow check does for conventional drilling.

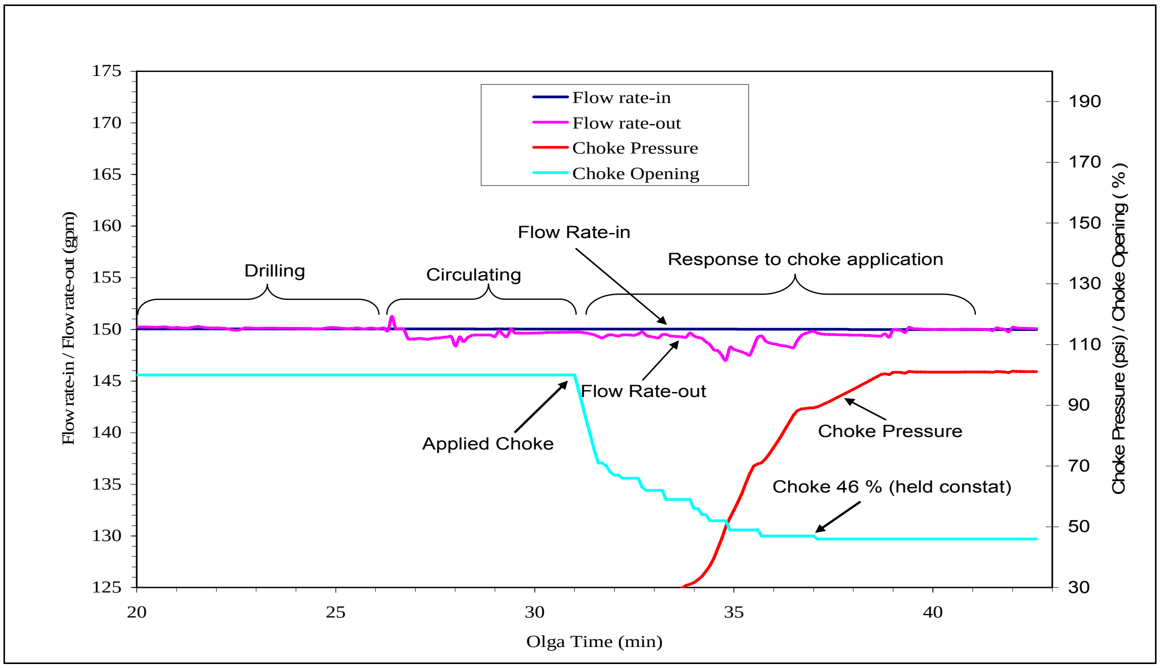

Figure 5.19: Response of choke pressure and flow rate-out to choke adjustments, well-x, case 0 - detection of false alarm

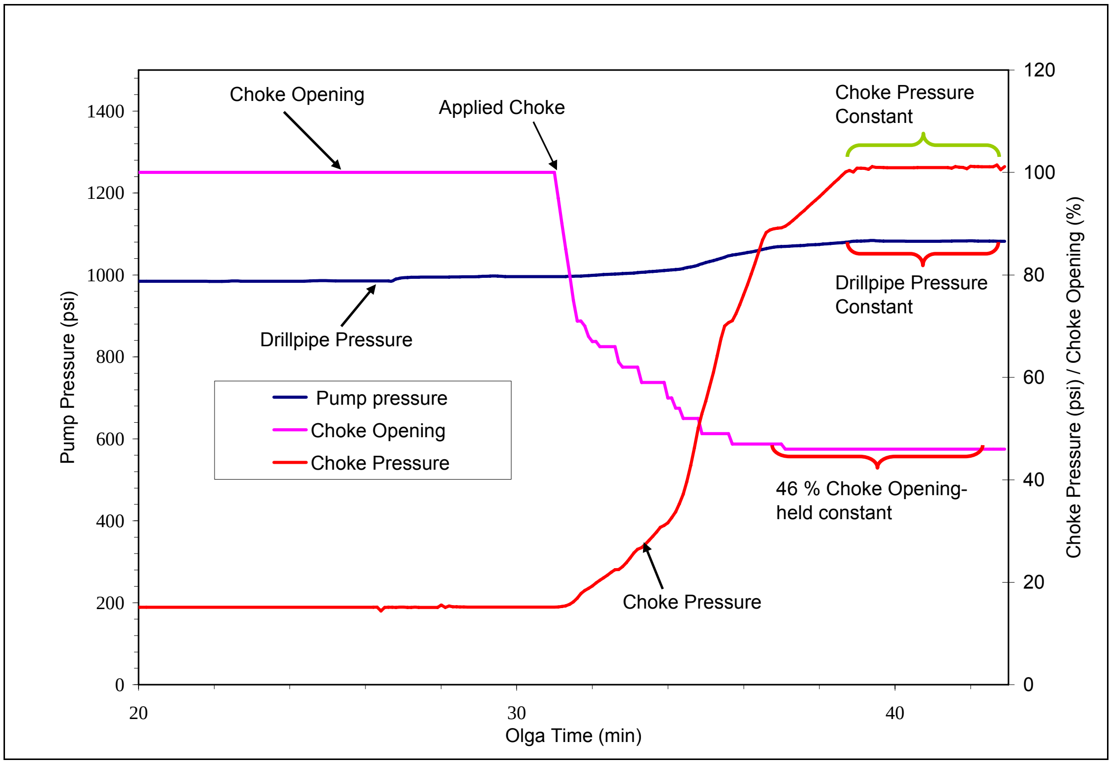

Figure 5.20: Response of drillpipe pressure and choke pressure to choke adjustments, well-x, case 0 - detection of false alarm

6. SIMULATION OF REPRESENTATIVE WELL -Z

6.1 Back Ground of Well Design

A sponsor provided a well description that was selected as representative of large hole applications of MPD. The well is a planned wildcat well in shallow water. The operator has identified this well as a potential candidate for MPD due to narrow margin between the pore pressure and fracture pressure in both the shallow and deeper sections of the well. Table 6.1 provides a summary of relevant well data, and the well schematic and the PP-FP profiles are shown in Figure 6.1 and Figure 6.2 respectively.

The 17-1/2 inch hole section of this well is an interesting candidate for MPD being a big hole with a rapidly increasing pore pressure (from 8.8 ppge at 3280 ft to 13.94 ppge at 4756 ft), and a progressively decreasing margin between the pore pressure and the fracture pressure. Therefore, it is a good candidate for simulated kicks to see the effectiveness of different initial responses for a large hole geometry. To maintain hydrostatic balance over the entire section interval from 3280 to 4756 ft, a minimum of 13.94 ppg mud is required without considering a trip margin. For these simulations, the well was drilled with a 12.51 ppg mud in order to induce kick in the lower section of the hole with a substantial section of open hole.

Table 6.1: Summary data of well-Z

Well Summary	
Well Name	Well Z
Vertical / Inclined	Vertical
Type of Well	Wildcat
Offshore / Onshore	Offshore
Water Depth	115 ft
KB	140 ft
TD	11480 ft
Objective	To Produce Gas / Oil
Mud Type	WBM / OBM

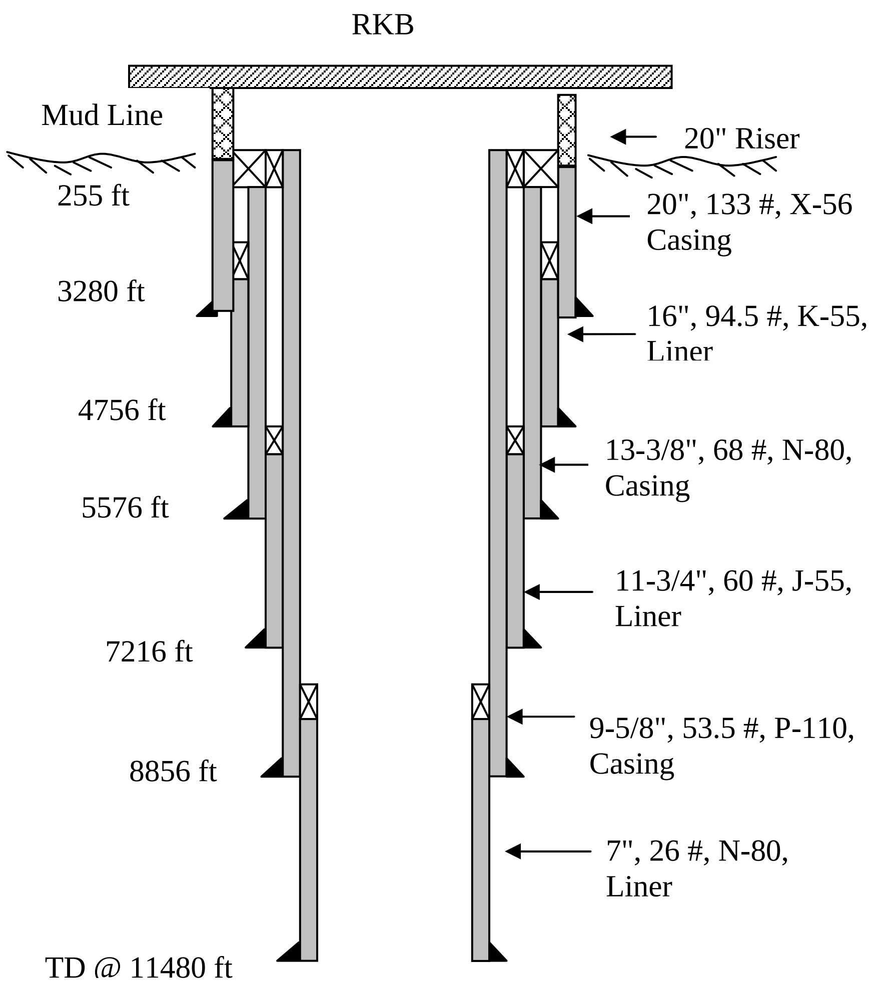

Figure 6.1: Well-Z schematic

The 17-1/2 inch hole section of the well was drilled with 80,000 lbf WOB, 100 RPM and 984 gpm mud flow rate using water-based mud as the drilling fluid. All simulations were conducted with a drilling mud represented with a Newtonian fluid rheological model.

6.2 Description of Simulations

Three different initial responses, namely ‘shut-in the well’, ‘apply back pressure’ and ‘increase in pump rate,’ were simulated for a range of possible well control scenarios to compare the results of the different initial responses. An overall summary of the reaction options and the controlling well conditions that were simulated in this study are presented in Table 6.2. A total of 14 simulations involving kicks while drilling 17-1/2 inch hole into a gas sand at 4500 ft were simulated. Varying kick sizes, differential pressures at the kick zone and fracture injectivity indices at the shoe were considered in these simulations.

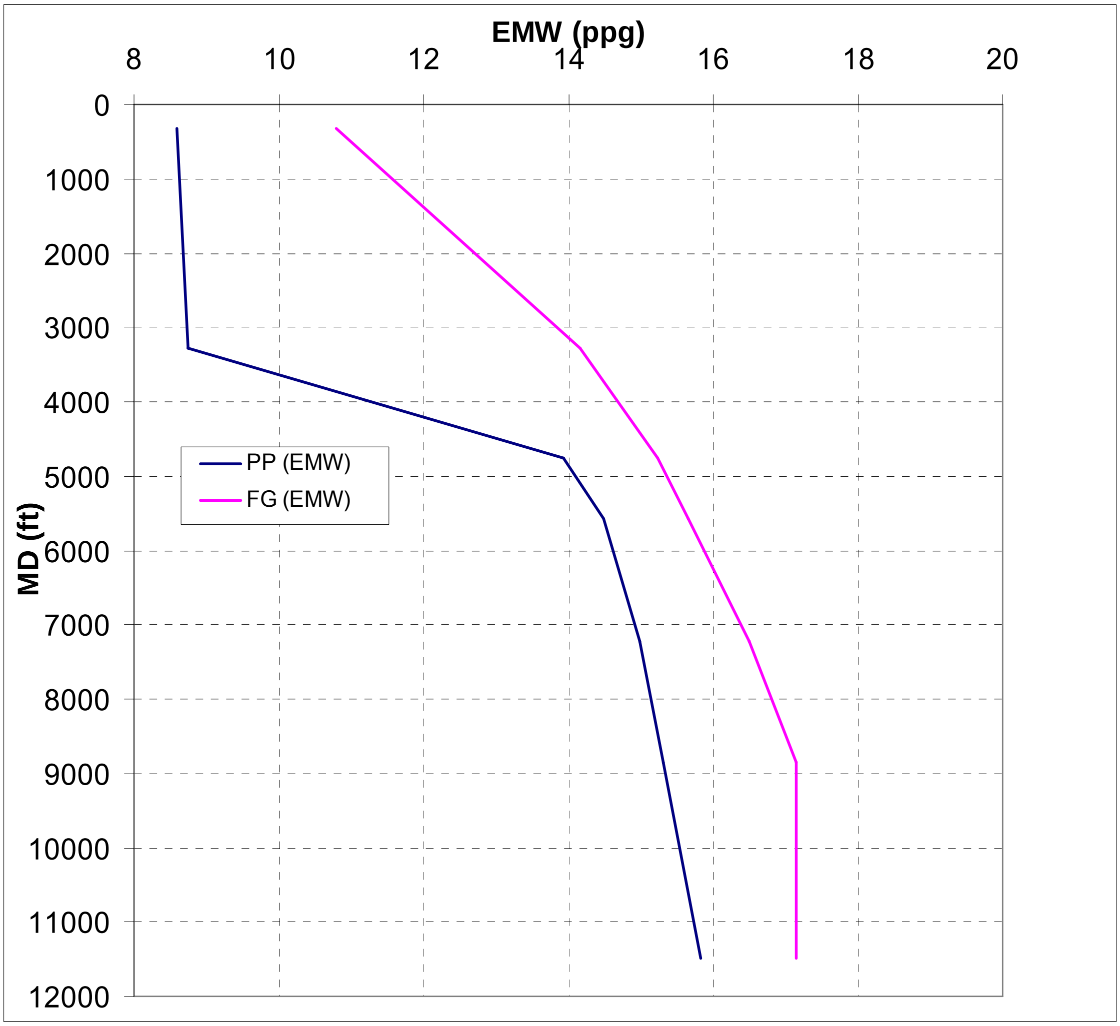

Figure 6.2: Well-Z Pore Pressure and Fracture Pressure Profile

One simulation, S/No 15 was run to observe the system behavior when the ‘increase back pressure’ reaction was taken to a false alarm.

A simulation was run to observe the system behavior when the ‘apply back pressure’ response was taken to a false alarm.

Table 6.2: Well - Z simulation cases

Sub Group	S/No	Case No	Initial Kick response	Mud weight	Reservoir Fluid	Kick Intensity		Productivity (MMSCF/day-psi)	Injectivity (MMSCF/day-psi)	Kick Volume (bbl)		Type of Mud	Remarks
						Static	Dynamic			High	Low		
1	1	Case 1	Increase Mud Flow Rate	12.51	Gas	0.49 ppg	32 psi	0.5564	0.0004		5.5	WBM	
	2	Case 2	Shut-in Well	12.51	Gas	0.49 ppg	32 psi	0.5564	0.0004		5.5	WBM	
	3	Case 3	Apply Back Pressure	12.51	Gas	0.49 ppg	32 psi	0.5564	0.0004		5.5	WBM	
2	4	Case 1A	Increase Mud Flow Rate	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5	WBM	
	5	Case 2A	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5	WBM	
	6	Case 3A	Shut-in Well	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5	WBM	
3	7	case 2A (longer)	Apply Back Pressure & circulate out kick	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5	WBM	
	8	case 3A (longer)-no float	Shut-in Well for longer duration	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5	WBM	
4	9	Case 2B	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4	50		WBM	
	10	Case 3B	Shut-in Well	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4	50		WBM	
5	11	Case 2C	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5	WBM	
	12	Case 3C	Shut-in Well	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5	WBM	
	13	case 2C-Alternate-1	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5	WBM	
		In this simulation, flow rate-out was forced to equal the flow rate-in by choke adjustment until the end of simulation.											
	14	case 2C-Alternate-2	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5	WBM	
		In this simulation, flow rate-out was forced to equal to the flow rate-in for about 15 minutes, and thereafter, attempted to maintain the drillpipe pressure constant by choke adjustments.											
	15	Case 0	Apply Back Pressure	12.51	Gas	Base Case – No Kick		0.5564	0.0004	-	-	WBM	To identify False Alarm

6.3 Simulations of Group 1

A kick was identified by an increase in return flow while drilling a gas sand at 4500 ft. At this depth, the mud hydrostatic pressure was 2927 psi (12.51 ppge), and the circulating bottomhole pressure was 3010 psi. The formation pore pressure at 4500 ft was 13 ppge, i.e. 3042 psi. The drilling was continued to 4532 ft in an underbalanced condition with 32 psi differential pressure until about 5.5 bbl of gas kick was taken in the well.

At that point, it was considered that the kick was identified, and each of the three primary alternative initial responses to stop the influx was simulated. The hard copy of the simulator input file is placed at Appendix A2. The results of these simulations are discussed in the subsequent subsections.

6.3.1 Increase Mud Flow Rate – Case 1

The mud flow rate in, pump rate was slowly increased **a**fter the kick was identified to increase the wellbore frictional pressure in an attempt to stop the influx. The difference between the mud flow rate in and out was monitored to identify stoppage of formation fluid influx. As the pump rate was increased, the drillpipe pressure also increased. At an 1155 gpm flow rate, the standpipe pressure reached the pump pressure limit of 6285 psi for 6 inch liners. At that time, the formation fluid influx had not stopped as evidenced by the return flow rate, which was 1169 gpm, 14 gpm higher than the pump rate. Figure 6.3 shows the time-based plot of the pump rate versus the mud flow rate-out. Figure 6.4 shows the pump pressure reaching its limit, and the formation fluid influx declining but not ceasing. Consequently, this was not a successful response for stopping the kick.

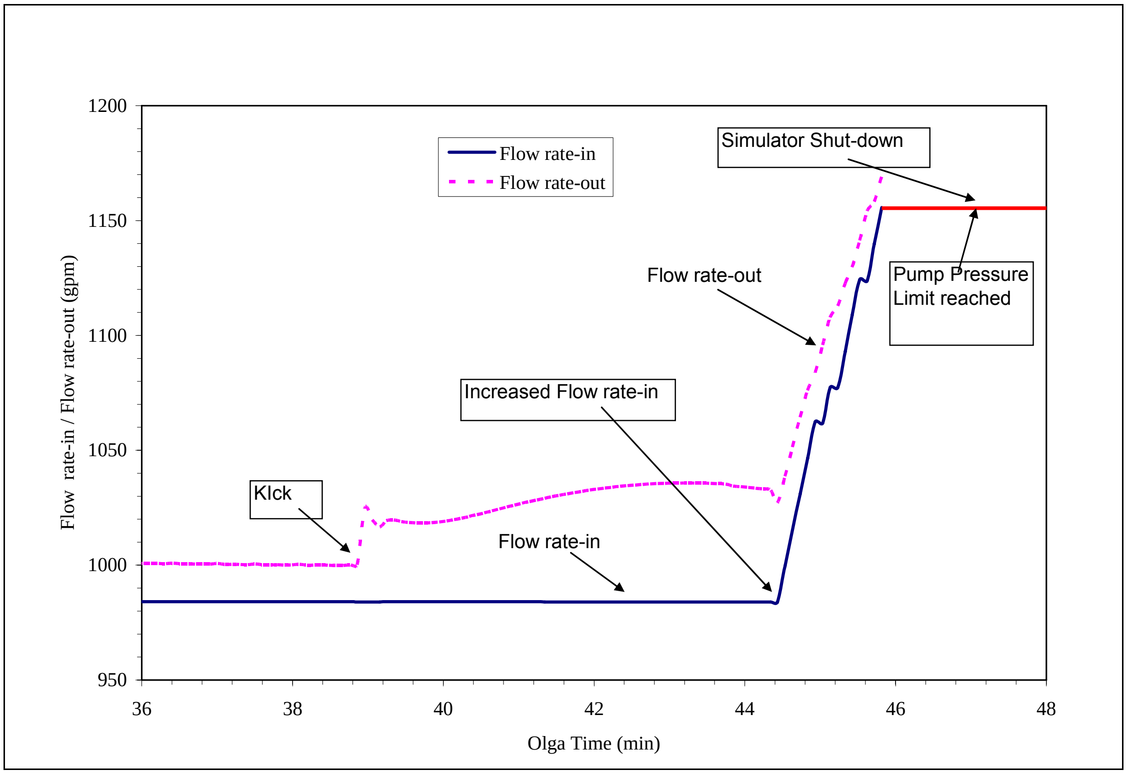

Figure 6.3: Flow rate-in and flow rate-out versus time
for well-z, group1, case1 – increase mud flow rate

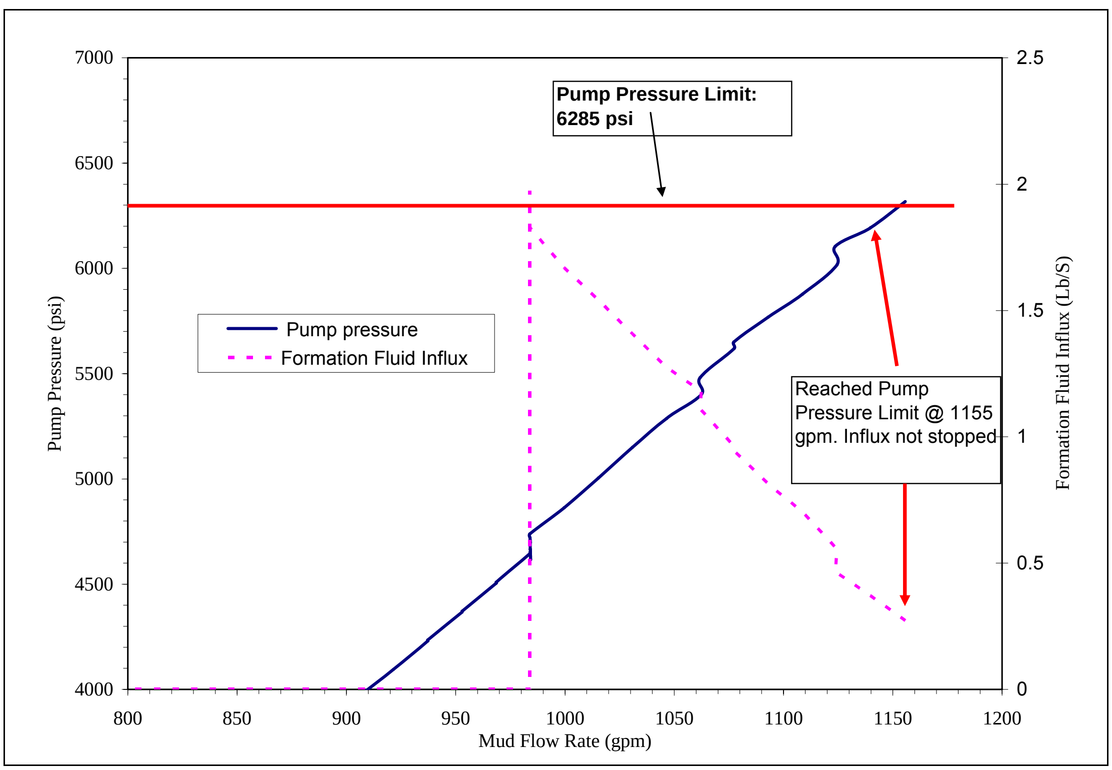

Figure 6.4: Mud flow rate, pump pressure, formation fluid influx versus time
for well-z, group1, case1 – increase mud flow rate

The friction factors for annular pressure losses are low in a bigger hole with large annular clearance, and therefore, the increase of mud pump rate has a smaller impact on the bottomhole pressure. The mud flow rate has a much higher impact on pump pressure due to the more rapid increase in frictional pressure losses in the drillstring because of the smaller flow areas through the drillpipe and the bit nozzles. In this study, the mud pump pressure limit was reached before the bottomhole pressure could adequately be increased to equal the pore pressure to stop the influx. The rig mud pump capacity plays an important role in determining whether dynamic well control will be effective or not, especially for a large size hole. For dynamic well control, the rig circulation system should have the capacity to pump at high circulating rate with high circulation pressure. To increase the pressure rating of the mud pump, the liner size has to be reduced, which reduces the maximum pump rate.

In this study, the simulator input data for the mud pump capacities was equivalent to having 3 National triplex mud pumps, model: 14P-220 with a pressure rating of 6285 psi for 6 inch liner and 540 gpm each pumping capacity (total: 1620 gpm with 100 percent volumetric efficiency), were used in the simulator input data.

MPD operations in big hole would require detailed hydraulics calculations during well design to determine the pump capacity required to dynamically control the well in the event of a kick. The pressure rating of the surface equipments in the circulation system would also need to match the requirement for a dynamic kill.

6.3.2 Apply Back Pressure – Case 2

The back pressure, i.e. choke or casing pressure, was gradually increased after the kick was identified with about 5.5 bbl of gain. The return flow rate was monitored to identify the stoppage of influx. At a reduced choke opening of 87 percent and 53 psi back pressure, the influx stopped at about 36 minutes into the simulation, see Figure 6.5. This was recognized by observing the return flow rate being the same as the flow rate-in. The choke pressure and the drillpipe pressure steadily increased in response to the reduction of choke opening size suggesting no lost returns during back pressure application. Figure 6.5 shows a composite time-based plot of formation influx rate, choke pressure, drillpipe pressure, bottomhole pressure and the choke opening. It may be seen that the choke pressure began slowly increasing at about 49 minutes due to gas migration effect after the formation fluid influx stopped.

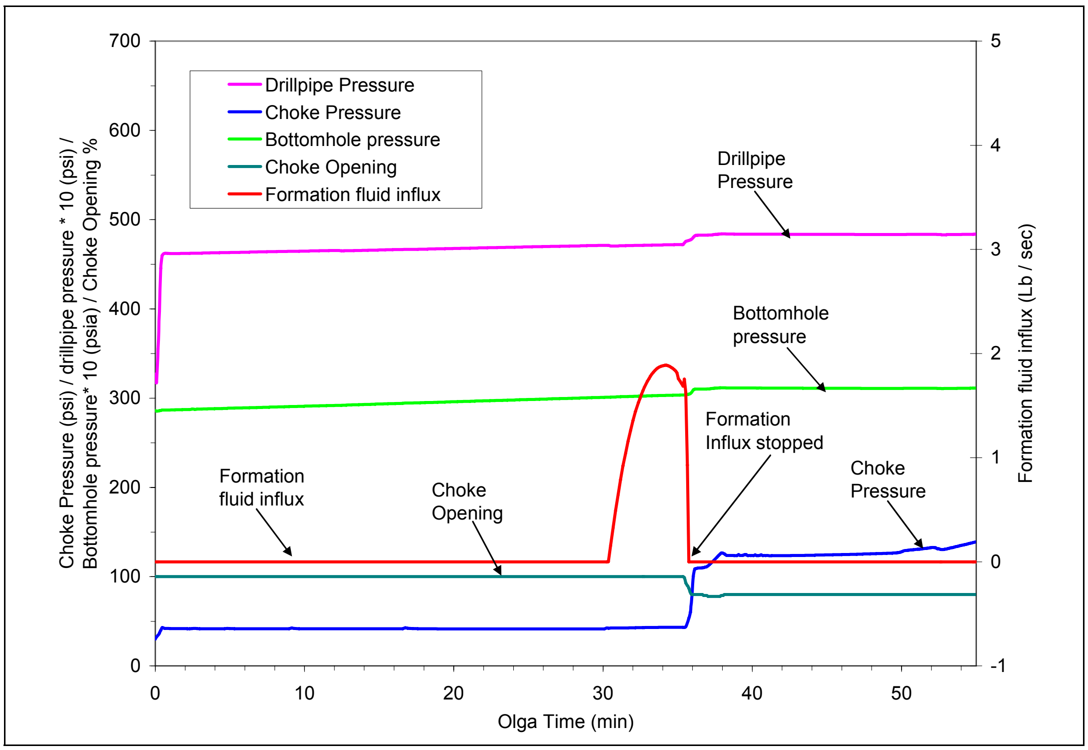

Figure 6.5: Well behavior versus time for well-z, group-1, case-2 – back pressure

6.3.3 Shut-in – Case 3

The well was shut-in after taking a 5.5 bbl gain. A conventional flow check was not carried out before shutting-in the well because the well was assumed to be strictly underbalanced before the kick was taken. However, a peak in the influx rate of formation fluid is shown in Figure 6.6. This is attributed to loss of annulus frictional pressure during gradual shut down of the mud pump. This peak could have been avoided by increasing the choke pressure to offset the loss of friction. After shut in, the influx stopped at a casing pressure of 74 psi which is slightly more than the casing pressure in the 'apply back pressure' option, as expected. As seen from Figure 6.6, a negligible amount of influx entered the wellbore before the influx stopped at 50 minutes. Similar to the 'back pressure' option, there were no signs of any lost returns in the wellbore after shut-in.

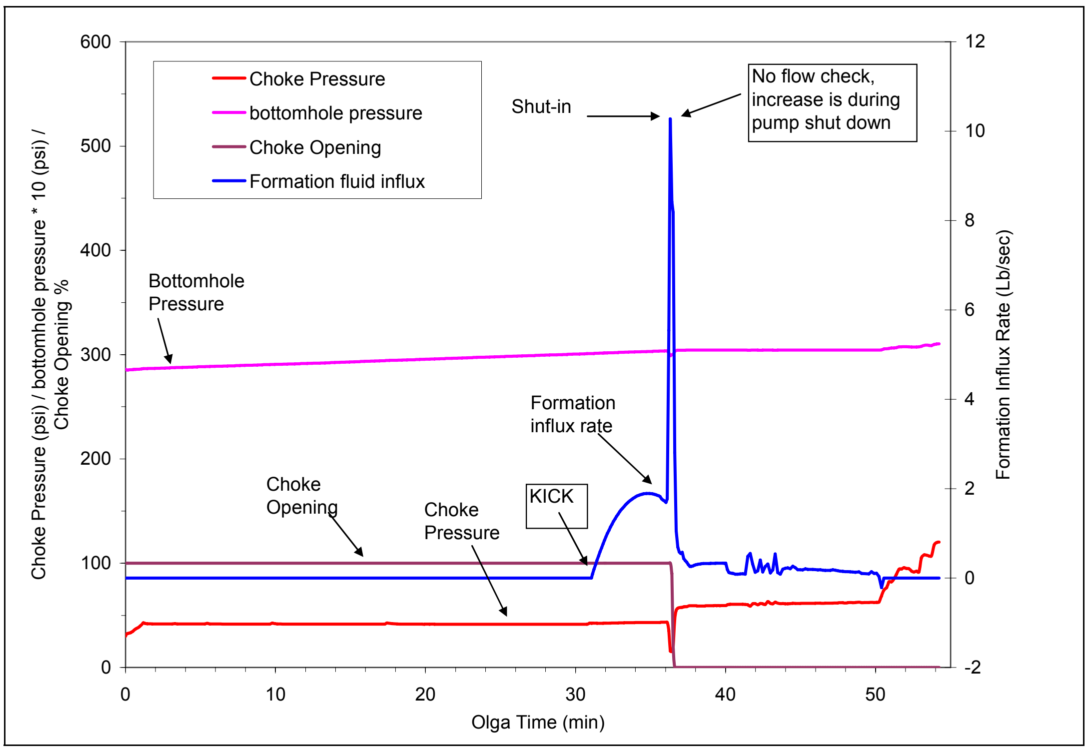

Figure 6.6: Well behavior versus time for well-z, group-1, case-3 - shut-in

6.3.4 Summary Discussions on Group 1 Simulations

The 'increase mud flow rate' reaction to a kick is not likely to be effective in large size holes due to low annulus frictional pressure loss in a large annular geometry. Rig mud pump capacity is therefore likely to be the limiting factor as to whether it is possible to stop the influx by higher wellbore frictional pressure. MPD operations in a bigger hole size require detailed hydraulics calculations in the planning stage to determine the required mud pump liner size to be used if stopping the influx by increasing mud flow rate is a desired reaction to a kick. A logical contingency is that one of the other reactions must be taken if the increase flow rate reaction does not conclusively stop the formation fluid influx. Also, a circulation sub[48] may be used in the BHA, so that the side port(s) may be opened to divert the flow in the annulus, bypassing the bit nozzles to reduce the pump pressure to achieve a higher circulation rate. Another method to increase the ECD is to reduce the annular clearance by using drillpipe with a larger OD and ID[15].

The ‘back pressure’ and conventional ‘shut-in’ options were equally effective for stopping the formation fluid influx for this well scenario. The casing pressure was lower in the case of the ‘back pressure’ option compared to the ‘shut-in’ option. A higher peak influx rate was observed in the shut-in option, but this should be eliminated if a pump shut down procedure appropriate to the CBHP method of MPD was followed. Given that both of these approaches successfully stopped formation feed-in without causing lost returns, these simulations do not provide a basis for evaluating these options for ease of confirming stoppage of feed-in or occurrence of lost returns

6.4 Simulation Results – Group 2

The purpose of these simulations was to determine whether any well control reaction would be effective with a narrow margin between the pore pressure and the fracture pressure. Therefore, this group of simulated gas kicks was conducted assuming a larger differential pressure at the kick zone compared to group 1 simulation cases. The pore pressure in the kick zone at 4500 ft was changed to 14 ppge from 13 ppge of the group 1 simulations. Mud weight was kept the same at 12.51 ppg to simulate kicks with a higher kick intensity of 1.49 ppge. With 14.15 ppge fracture pressure at the previous casing shoe at 3280 ft, the margin between the pore pressure and the fracture pressure was further narrowed to 0.15 ppge compared to group 1 simulations. Other than changing the pore pressure data, all input data in this group of simulations were the same as for the group 1 simulations.

The simulations began by drilling into the kick zone. A kick was identified by an increase in return flow while drilling a gas sand at 4500 ft with the same drilling parameters as in group 1 simulations. The bottomhole pressure at that time was 3010 psi, which was 266 psi less than the pore pressure of 3276 psi. The mud hydrostatic pressure at 4500 ft was 2927 psi, and the annular frictional pressure was 83 psi. The well was drilled to 4513 ft in an underbalanced condition until the kick volume reached 5.5 bbl as in group 1 simulations. Due to the larger negative pressure differential at the kick zone, the influx rate was higher than in the group 1 simulations with the same reservoir productivity index. Simulations were run to verify the effectiveness of each of the three different initial reactions to a kick. The results of these simulations are described in the following sections.

6.4.1 Increase Mud Flow Rate – Case 1A

The formation fluid influx could not be stopped by increasing mud pump rate due to pump pressure limitation described in section 6.3.1. Figure 6.7 shows the time-based plot of mud flow-in due to pump rate versus mud flow-out. From this plot, it may be seen that the increase in mud flow rate had hardly any effect on stopping the influx when the pump rate was increased from 994 gpm to 1140 gpm. This was due to the larger negative pressure differential pressure at the kick zone compared to group 1 simulations.

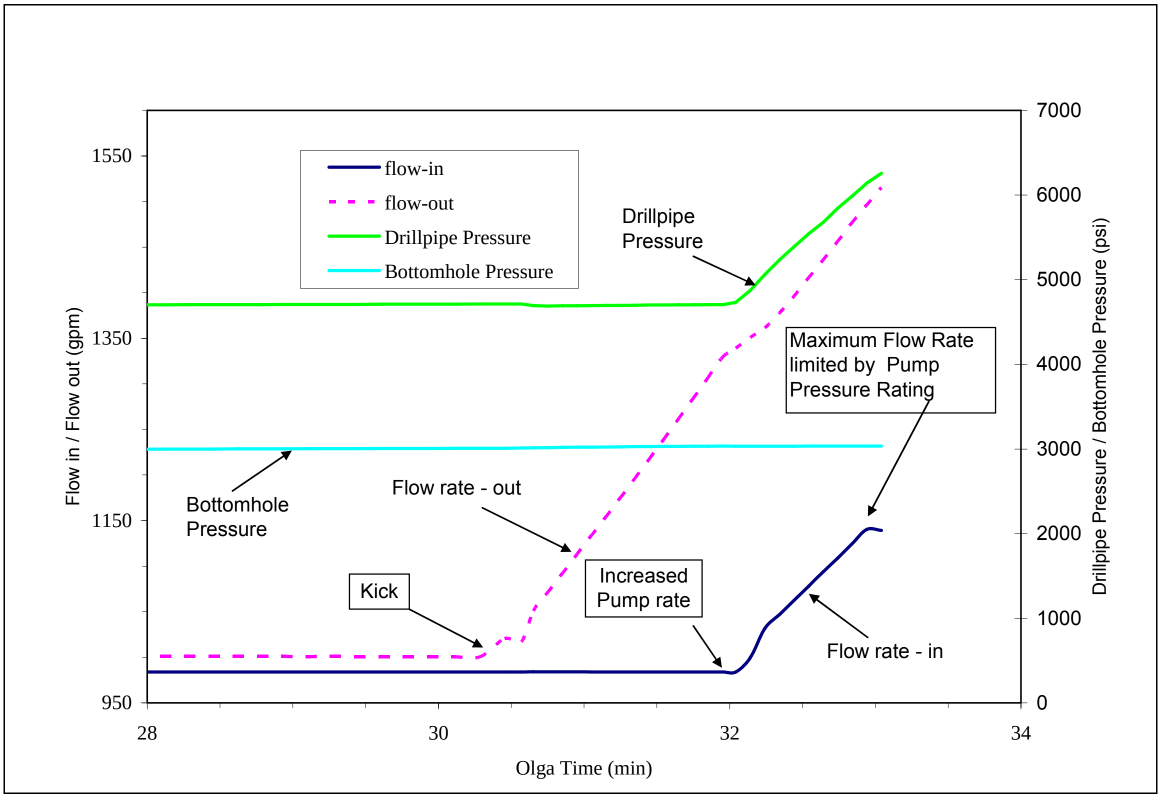

Figure 6.7: Flow rate-in and flow rate out versus time for well-z, group-2, case-1A - increase mud flow rate

6.4.2 Increase Back Pressure – Case 2A

A 5.5 bbl gas kick was taken in the well while drilling a gas sand at 4500 ft. Drilling was discontinued, and back pressure was gradually applied through the choke while monitoring and comparing the return flow rate with flow rate-in. Figure 6.8 shows a composite time-based plot of mud flow rate-in, mud flow rate-out, choke pressure and drillpipe pressure. From this plot, we noticed possible lost returns at about 41 minutes of simulation time, and at that time the choke pressure was 355 psi. The maximum casing pressure before formation fracture under static conditions with only mud above the shoe was 279 psi with 12.51 ppg mud weight and 14.15 ppge fracture pressure at the shoe. At 279 psi surface pressure, the return flow rate was 1057 gpm, which is 73 gpm more than the flow rate-in.

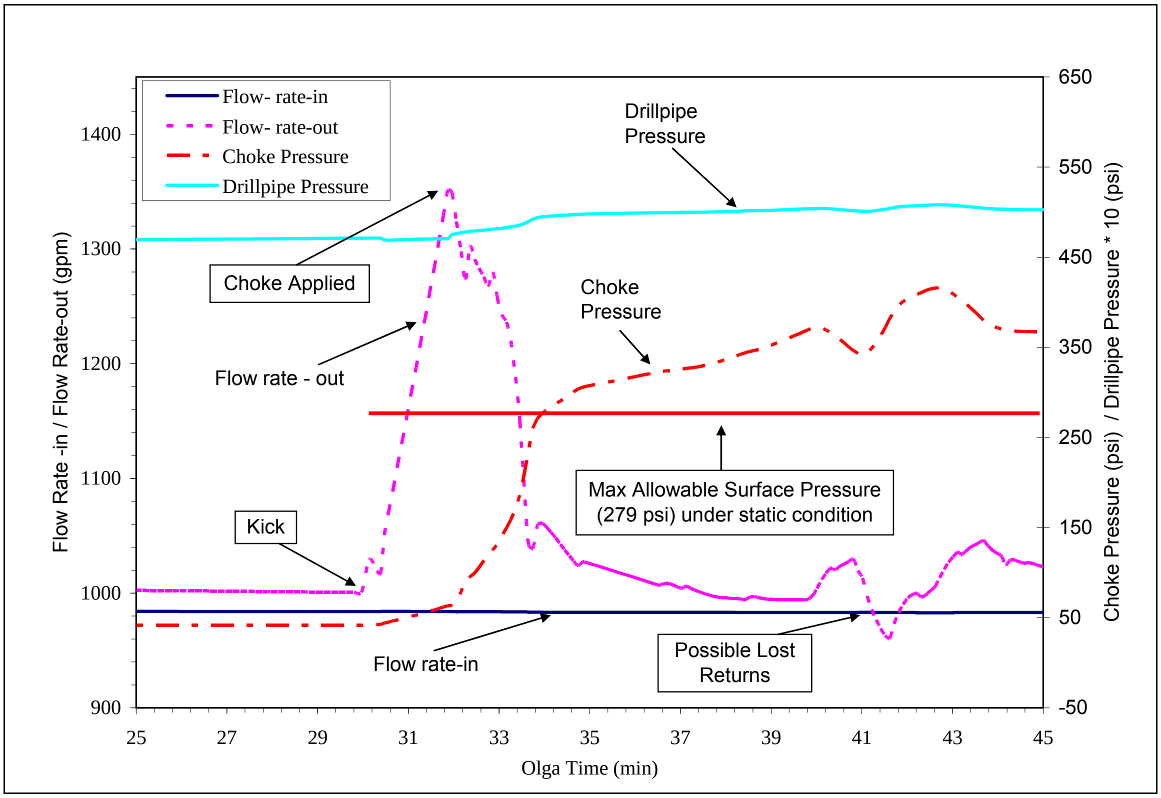

Figure 6.8: Well behavior versus time for well-z, group-2, case-2A - back pressure

This implied that stopping influx by application of back pressure was not successful. The subsequent increases in casing pressure exceeded the maximum allowable and probably caused formation fracture.

Figure 6.9 shows a snapshot of the formation flow profile at 35 minutes into the simulation. It confirms that simultaneous kick feed-in and losses were taking place downhole before the possible lost returns were observed at the surface at 41 minutes into the simulation. It was expected that lost returns would result when the total of choke pressure, hydrostatic pressure and annular frictional pressure losses caused the pressure at the shoe to exceed the 14.15 ppge fracture pressure. However, there is no clear indication of lost circulation from the choke pressure and drillpipe pressure in Figure 6.8

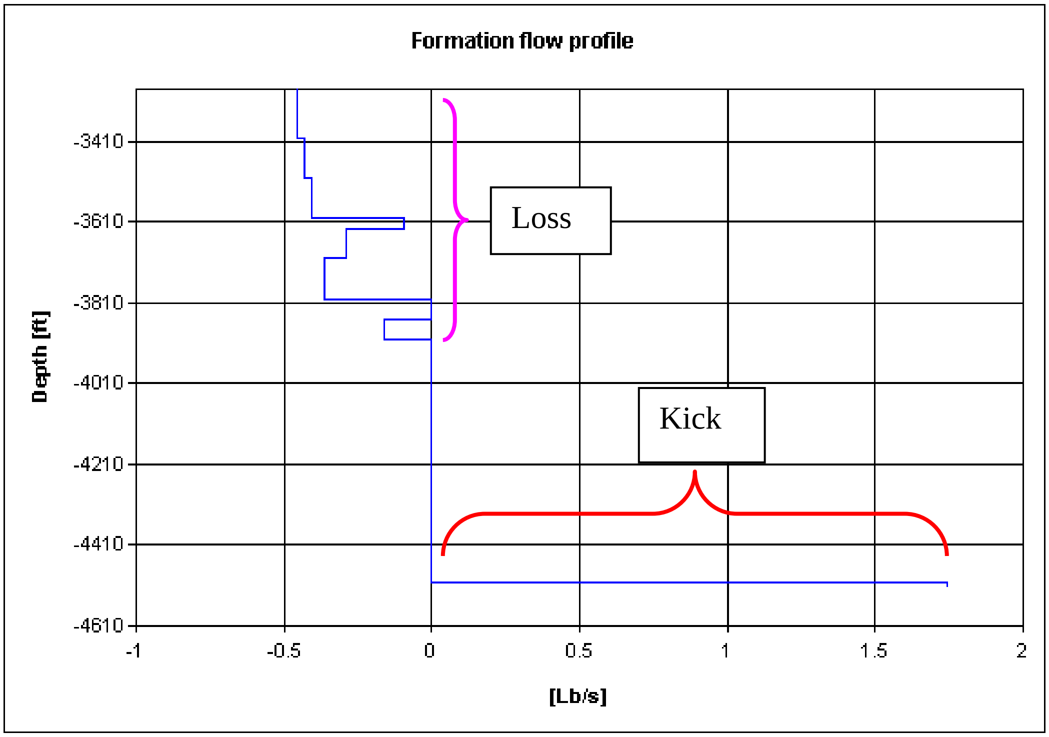

Figure 6.9: Snapshot of simultaneous kick and loss at 35 minutes for well-z, group-2, case-2A - back pressure

6.4.3 Shut-in – Case 3A

The well was shut-in after taking a 5.5 bbl kick while drilling a gas sand at 4500 ft. Figure 6.10 shows the time-based plot of choke pressure, formation total flow and choke opening size. With a float installed in the drillstring, the shut-in casing pressure is the only recordable parameter to indicate subsurface well behavior. In this case the increase of choke pressure after shut-in may be due to migration of initial kick or a combination of migration and continuous feed-in of formation fluid into the wellbore. Also, it was not possible to determine lost returns from the shut-in casing pressure. From the ‘formation total flow’ plot, it may be noticed that there is a net losses in the well after 35 minutes into the simulation. This indicates fracture in the wellbore. However, whether the formation fluid influx has stopped or not, can not be concluded.

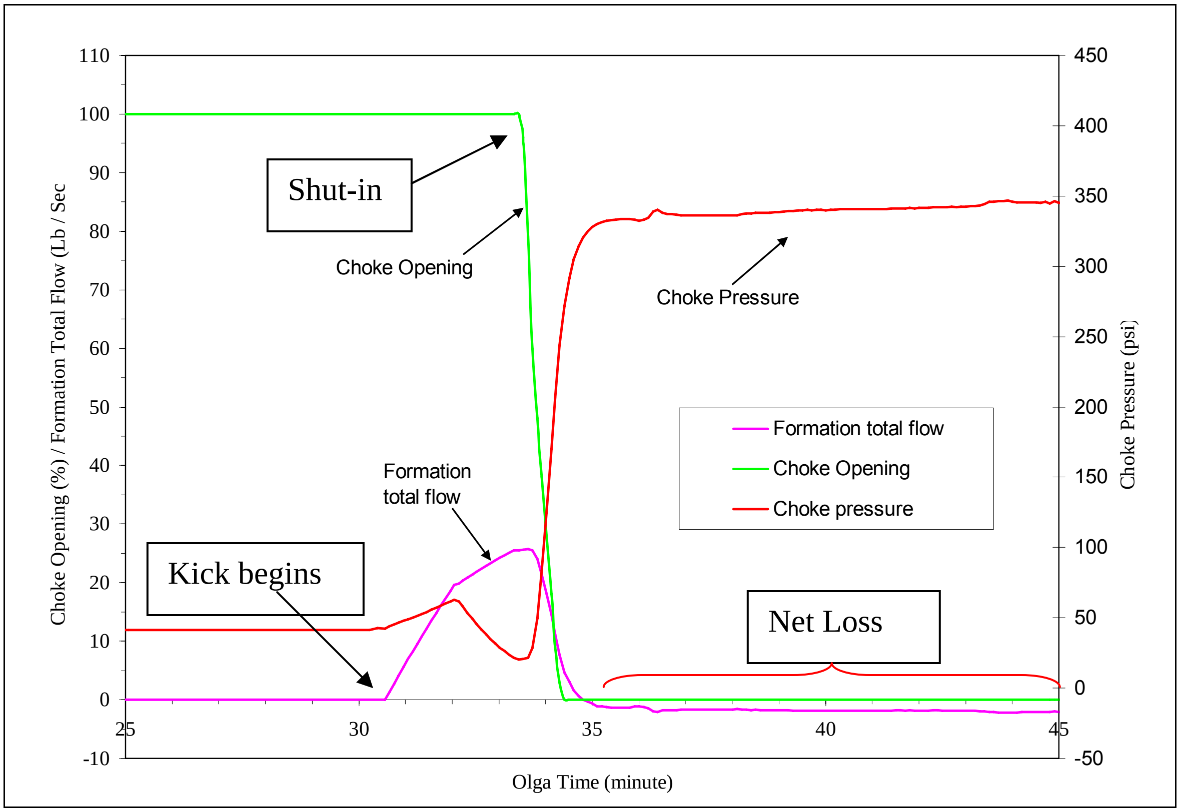

Figure 6.10: Choke pressure, choke opening and formation total flow for well-z, group-2, case-3A - shut-in

6.4.4 Summary Discussions of Group 2 Simulations

The ‘shut-in’ and ‘apply back pressure’ reactions to a kick are not favorable in an extremely low kick tolerance situation, because of susceptibility of formation fracture and lost returns. The ‘apply back pressure’ reaction undertaken on a 5.5 bbl gas kick in a 0.15 ppge kick tolerance was not successful in stopping the influx because formation breakdown occurred at the casing shoe before the bottomhole pressure could be increased enough to stop formation feed-in.

Stoppage of formation feed-in and / or lost returns could not be concluded by shut-in reaction with shut-in casing pressure as the only measurable parameter with a drillpipe float installed in the drillstring.

The 'increase flow rate' option has less risk of fracturing formation because it solely uses ECD over the mud hydrostatic pressure to increase the bottomhole pressure for counterbalancing the pore pressure. However, in a big hole, because of larger annular clearance, response of ECD to the increase in mud flow rate is relatively low. The mud flow rate required to adequately increase the ECD may not be achievable due to pump pressure limitation. Use of a circulating sub[48] in the BHA and larger size drillpipe[15] will help to increase the ECD.

Therefore, for a big hole section with low kick tolerance, the well control issues need to be adequately addressed during MPD well design.

6.5 Simulation Results – Group 3

Because short simulations did not allow conclusive interpretation of flow stoppage or lost returns, two simulations, one with 'apply back pressure' and the other with 'shut-in' as initial reactions were run in this group for a longer time (simulating about 3 hours) than the group 2 simulations. In this group of simulations, the drillpipe float was removed so that the drillpipe pressure could be monitored as an indicator of the bottomhole pressure after the well was shut-in. All other input data including the drilling parameters were kept same as in the group 2 simulations. The well was drilled to the same depth, and the same 5.5 bbl of gas kick was taken as in case of group 2 simulations. The purpose of running simulations for a prolonged time in the 'apply back pressure' option was to ascertain whether the well can be controlled even after loosing returns and lost returns can be conclusively identified. For the shut-in option, the purpose was to see if lost returns can be identified by drillpipe and choke pressure response during a longer shut-in period. All cases were run with the same formation fracture injectivity of 0.0004 mmscfd / psi of the previous cases for well Z. This low injectivity causes low rates of lost returns and adds to the difficulty in detecting the lost returns

6.5.1 Apply Back Pressure - Case 2A-longer

An increasing back pressure was applied with the choke after a gas kick of 5.5 bbl was taken in the well, and the decreasing return flow rate was monitored. Immediately after equalizing the return flow rate with the pump rate, control was switched over to maintain constant drillpipe and bottomhole pressures by adjusting the choke. Figure 6.11, 6.12, 6.13 and 6.14 show composite time-based plots of choke pressure, flow rate in, flow rate out, drillpipe pressure and bottomhole pressure from 30 to 45 minutes, 45 to 90 minutes, 90 to 135 minutes and 135 to the end of the simulation respectively.

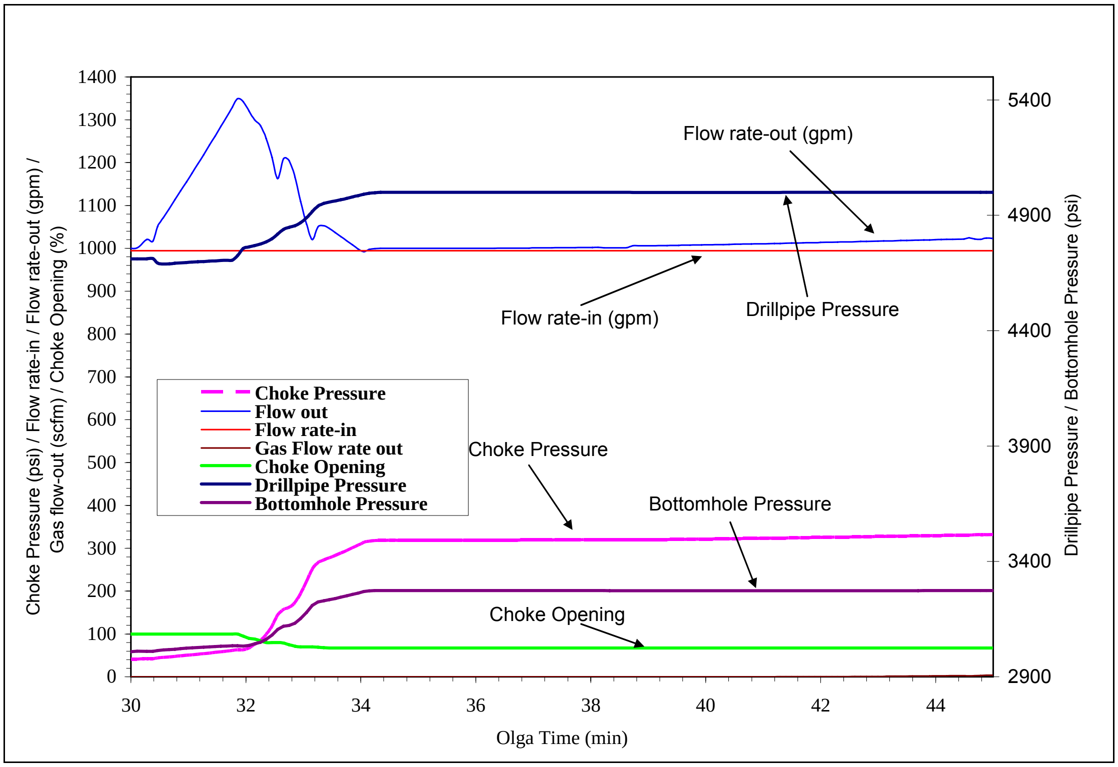

Figure 6.11: Well behavior versus time (30 to 45 minutes) for well-z, group-3, case-2A-longer – back pressure

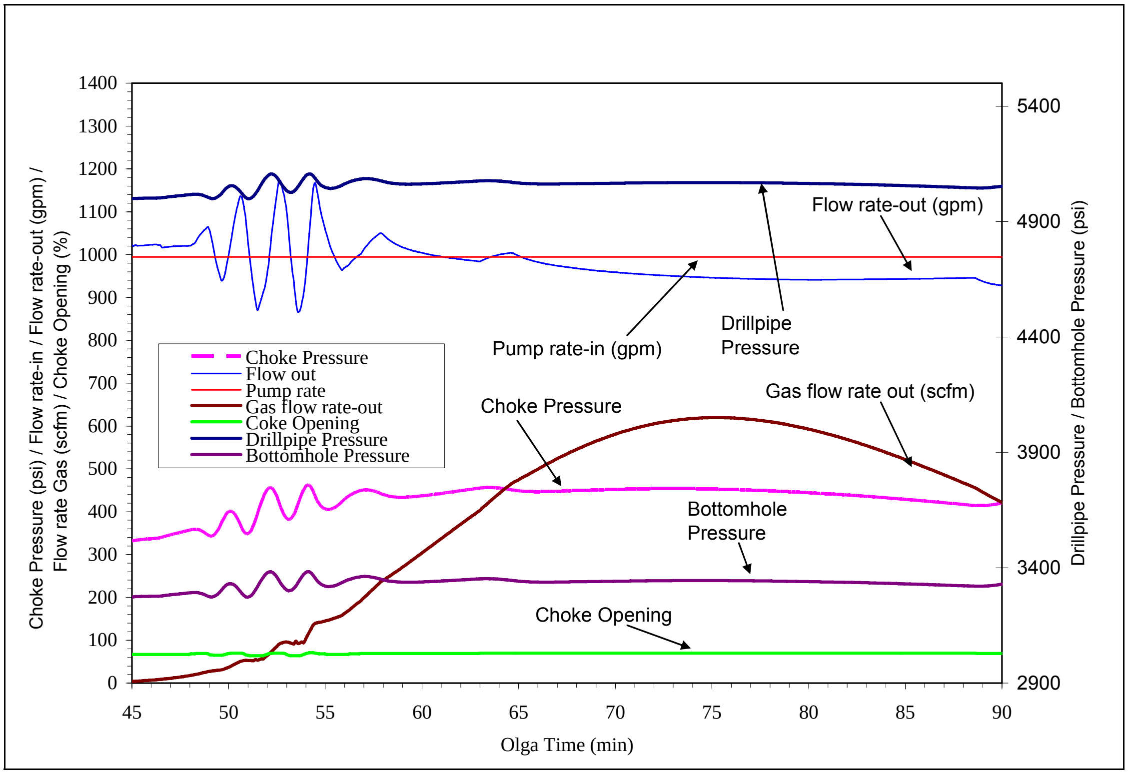

Figure 6.12: well behavior versus time (45 to 90 minutes) for well-z, group-3, case-2A-longer – back pressure

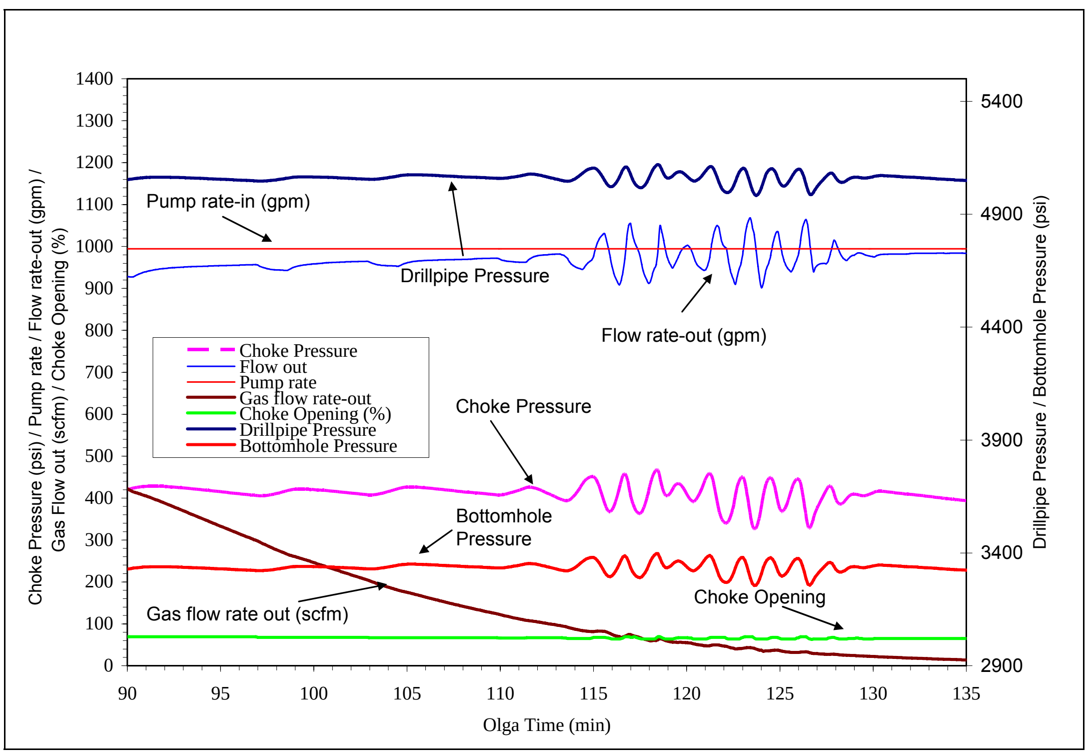

Figure 6.13: well behavior versus time (90 to 135 minutes) for well-z, group-3, case-2A- longer – back pressure

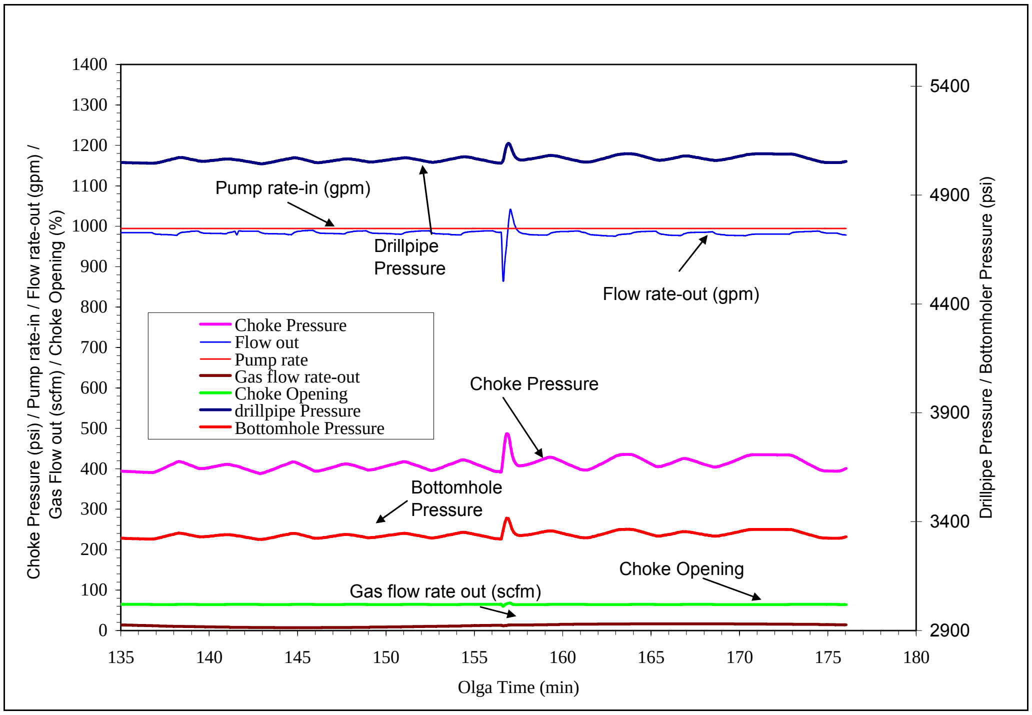

Figure 6.14: well behavior versus time (135 to 176 minutes) for well-z, group-3, case- 2A- longer – back pressure

The kick was successfully circulated out in this simulation by maintaining a constant bottomhole pressure, despite loosing mud due to exceeding the fracture pressure below the casing shoe. Figure 6.11 through 6.14 show that after the initial reaction, the bottom hole pressure was maintained greater than the pore pressure of 3276 psi at the kick zone, and evidently there was no secondary kick during the kick circulation. Figure 6.15 shows the formation fluid total flow during the simulation run and it can be seen that lost returns continued at a low rate during kick circulation.

Figure 6.16 presents the liquid holdup profile at the end of simulation, which shows that the liquid hold up is nearly 100 % meaning almost all the gas had been circulated out.

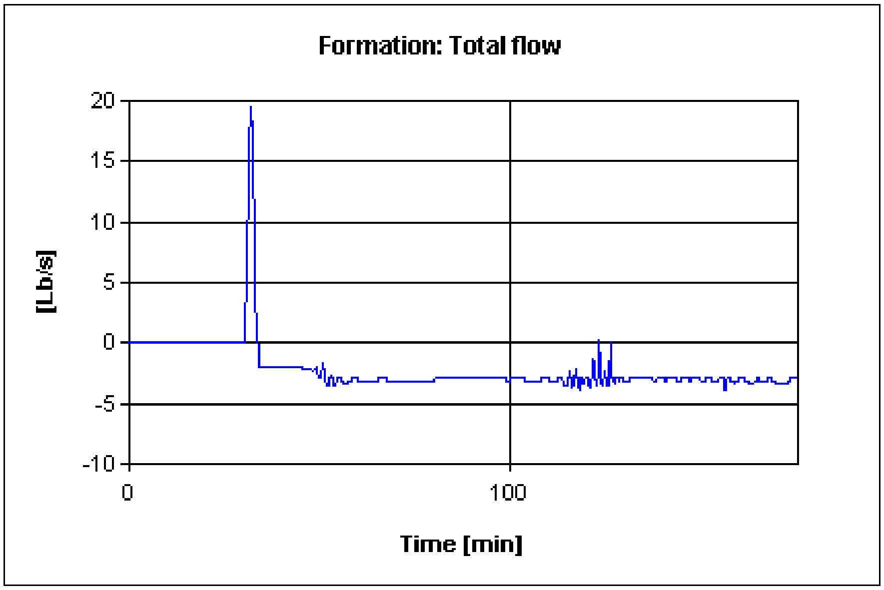

Figure 6.15: Formation total low versus time
for well-z, group-3, case-2A-longer - back pressure

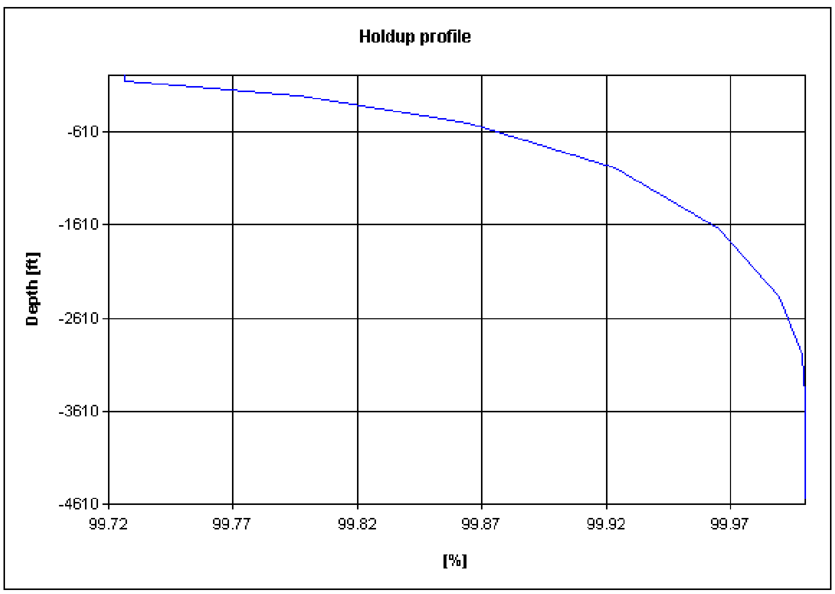

Figure 6.16: Liquid holdup profile at the end of simulation
for well-z, group-3, case- 2A-longer - back pressure

Figure 6.17 shows the pressure profiles at the end of simulation. From this plot, it may be seen that the well bore pressure was higher than the pore pressure at all depths and higher than the fracture pressure limit at several depths in the openhole section of the well, which is the reason that some losses were still being experienced.

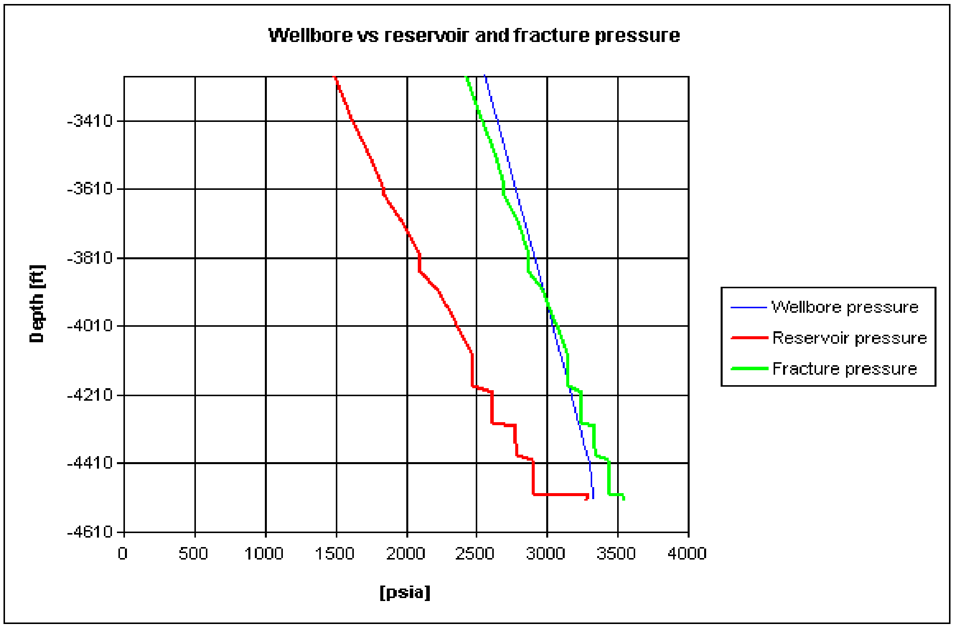

Figure 6.17: Pressure profiles at the end of simulation
for well-z, group-3, case-2A-longer - back pressure

6.5.2 Shut-in - Case 3A-longer

The well was shut-in for a longer time after the kick was identified, and the changes in the drillpipe and the choke pressures were monitored. Figure 6.18, 6.19, 6.20 and 6.21 show composite plots of drillpipe, choke and bottomhole pressures from 30 to 45 minutes, 45 to 90 minutes, 90 to 135 minutes, and 135 to 180 minutes respectively. Both the drillpipe and the choke pressures increased during gas migration up to about 135 minutes, and thereafter, a continuous declining trend was observed. The maximum choke and drillpipe pressures observed were 818 psi and 756 psi (ignoring a pressure spike at 162 min) during gas migration. The bottom hole pressure also increased gradually after shut-in and reached a maximum of 3680 psi during gas migration before starting to decline slowly from about 135 minutes until the end of the simulation. The bottomhole pressure at the end of simulation was 3473 psi, which is more than the pore pressure suggesting no formation fluid influx into the wellbore. The decline of the choke pressure, drillpipe pressure and the bottomhole pressure probably had started when the gas migration was essentially complete and nearly all the gas had accumulated at the surface. The decline of pressures is probably due to losses in the induced fracture after the gas migration was completed. As seen from Figure 6.22, there were continuous losses in the well from about 35 minutes after the choke was closed. However, initially this was masked by the increasing trend of the drillpipe and the choke pressure during gas migration up the wellbore.

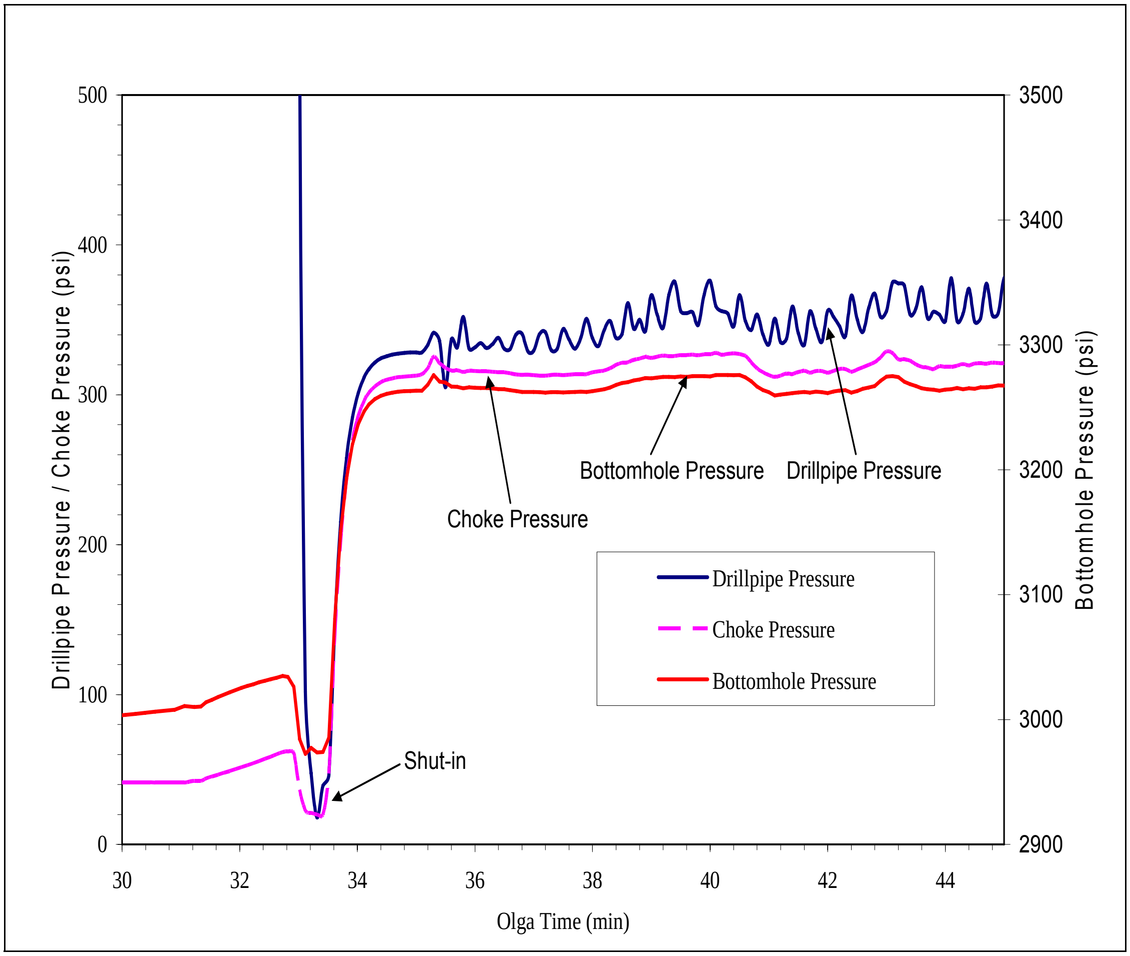

Figure 6.18: Choke pressure, bottomhole pressure and drillpipe pressure from 30 to 45 minutes for well-z, group-3, case-3A-longer -shut-in

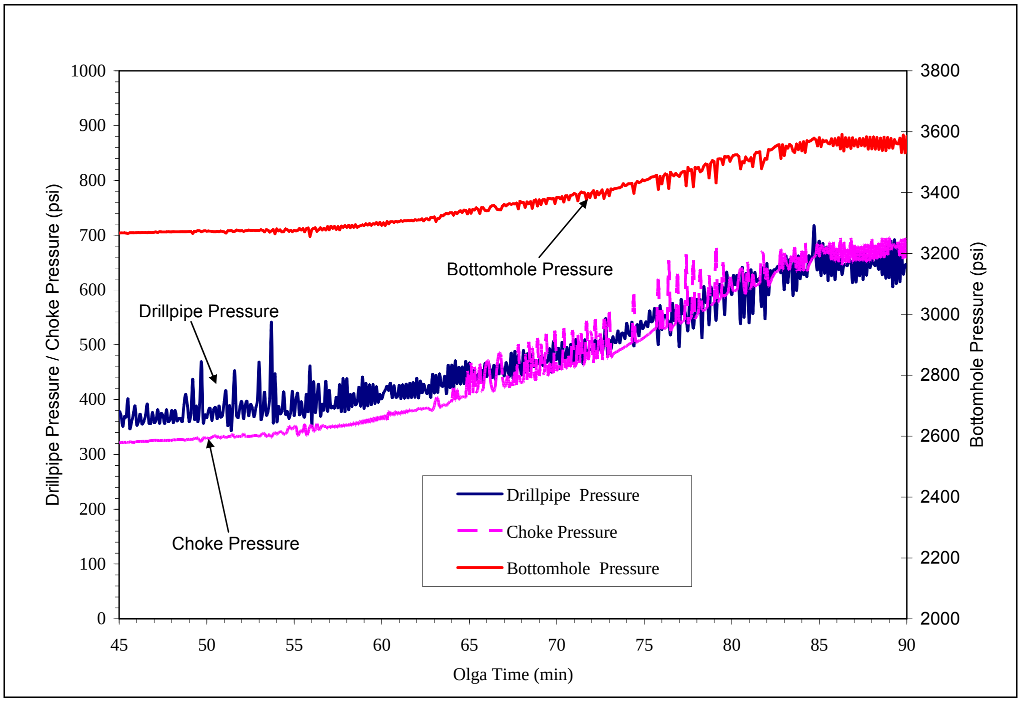

Figure 6.19: Choke pressure, bottomhole pressure and drillpipe pressure from 45 to 90 minutes, well-z, group-3, case-3A-longer - shut-in

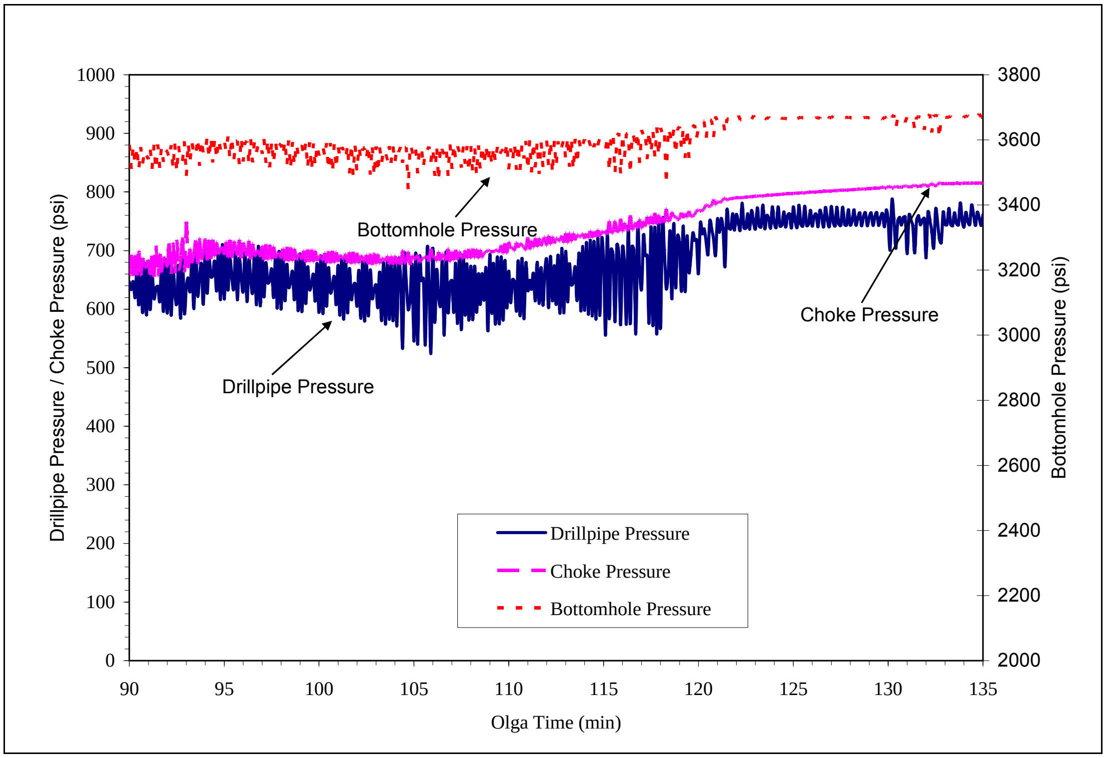

Figure 6.20: Choke pressure, bottomhole pressure and drillpipe pressure from 90 to 135 minutes, well-z, group-3, case-3A-longer - shut-in

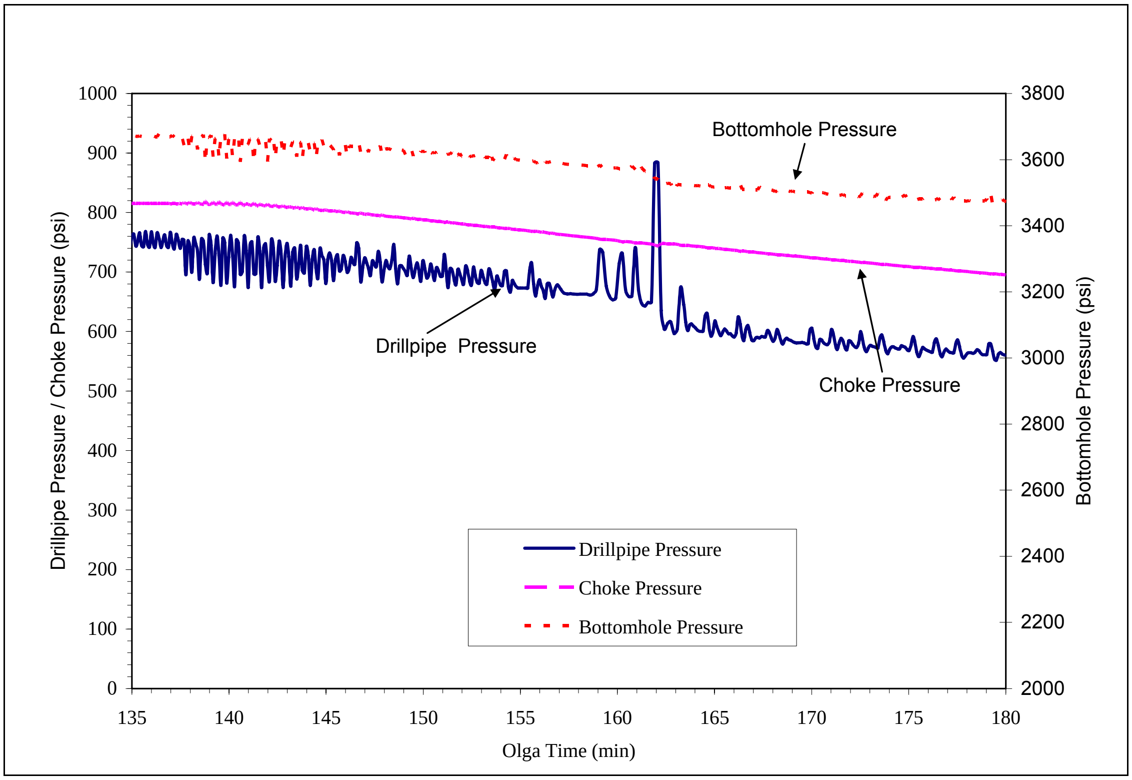

Figure 6.21: Choke pressure, bottomhole pressure and drillpipe pressure from 135 to 180 minutes, well-z, group-3, case-3A-longer - shut-in

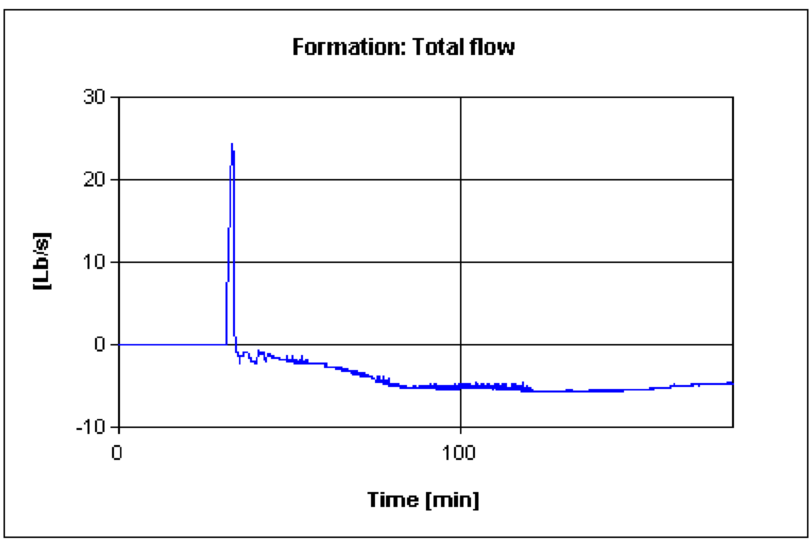

Figure 6.22: Formation total flow for well-z, group-3, case-3A-longer - shut-in

Figure 6.23 shows the liquid holdup profile at the end of simulation. It may be seen that nearly all the gas had accumulated at the surface at the end of simulation.

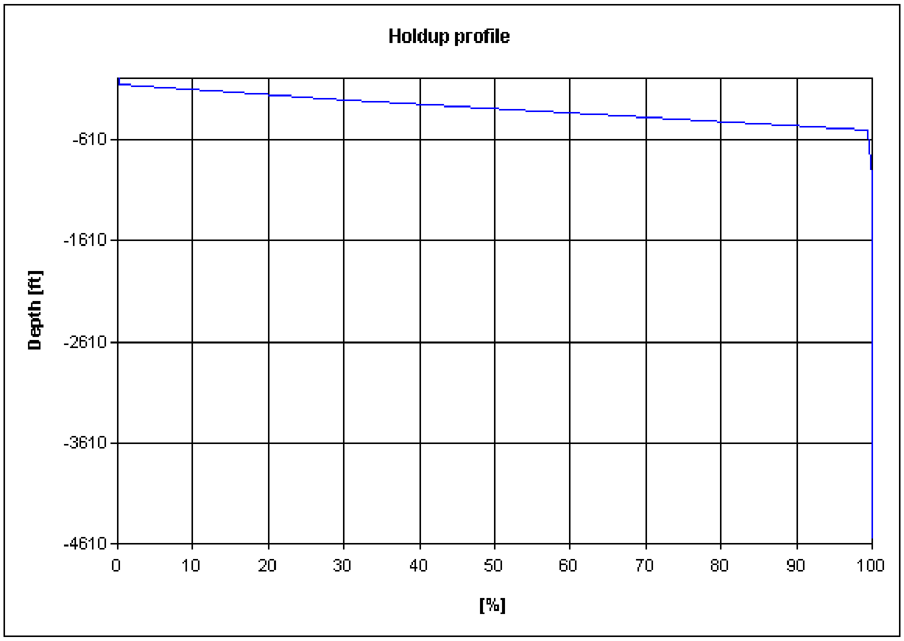

Figure 6.23: – Liquid holdup profile at the end of simulation
for well-z, group-3, case-3A-longer - shut-in

Figure 6.24, 6.25 and 6.26 show the liquid holdup profiles at 94 minutes, 127 minutes and 165 minutes, respectively. From these plots, it may be seen that the liquid holdup at the kick zone remained 100 % from 94 minutes to the end of simulation suggesting stoppage of influx. Bottomhole pressures were also more than the pore pressure during this time.

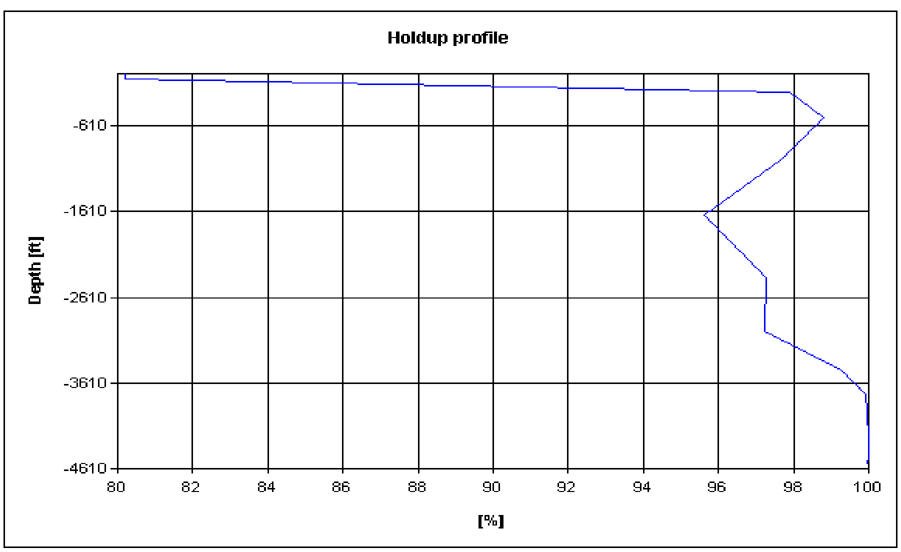

Figure 6.24: Liquid holdup profile at 94 minutes
for well-z, group-3, case-3A-longer - shut-in

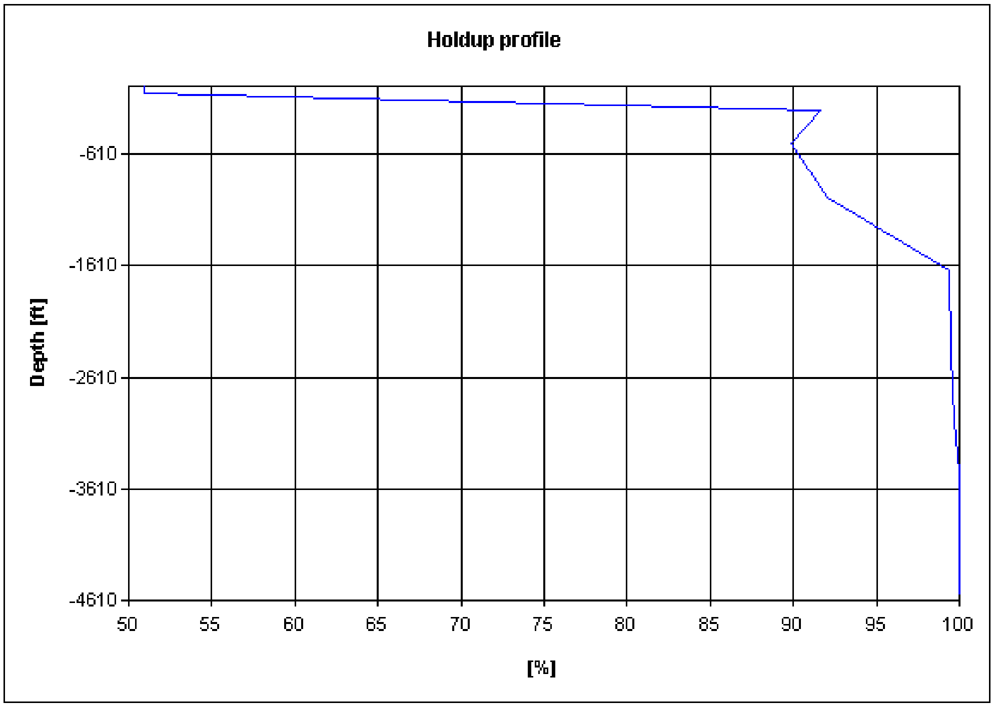

Figure 6.25: Liquid holdup profile at 127 minutes
for well-z, group-3, case-3A-longer - shut-in

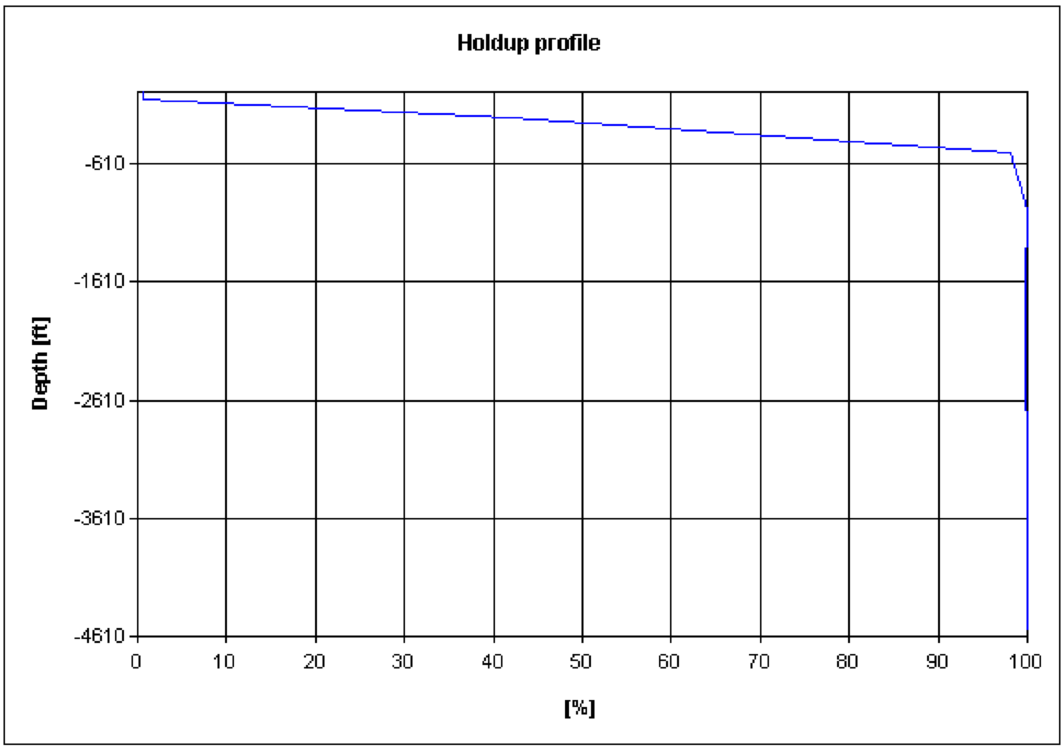

Figure 6.26: Liquid holdup profile at 165 minutes
for well-z, group-3, case-3A-longer - shut-in

6.5.3 Summary Discussions on Group 3 Simulations

The result of the simulations of the ‘apply back pressure’ and shut-in options in this group suggests that in spite of formation fracture, it may be possible to stop formation flow with either method. Likewise, it was possible to circulate the kick out by maintaining the drillpipe pressure constant with choke adjustment while continuing to circulate at the same pump rate. However, these results are not expected to be generally applicable. The low formation fracture injectivity resulted in such low loss rate that the wellbore was essentially intact despite the lost returns.

Conclusive evidence does not exist initially for either the stoppage of influx or the initiation of lost returns. The rate of lost returns is so small that losses are only evident late in the simulations by comparison of rates in and out for the ‘apply back pressure’ case and decline in surface pressure for the ‘shut-in’ case. Confirmation of successful stoppage of formation feed-in is even less conclusive. For the ‘apply back pressure’ case, this becomes really evident only after the gas flow rate at the surface declines to a negligible level. For the ‘shut-in’ case, it might be concluded based on the shut-in drillpipe and casing pressures having the same increasing trend versus time. However, this is conclusive only if no gas is allowed to enter the drillpipe. If that condition is met, then additional gas feed-in would cause the casing pressure to increase more rapidly than the drillpipe pressure.

There is little obvious difference between the ‘apply back pressure’ and ‘shut-in’ options as on initial response for these cases. The ‘increase pump rate’ response, in contrast, was unsuccessful in stopping formation feed-in.

6.6 Simulation Results Group 4

Two simulations were run in this group to study the effectiveness of the ‘apply back pressure’ and the ‘shut-in’ options for control of a larger kick volume with a higher assumed injectivity when the fracture pressure is exceeded. Consequently, the simulator input data for injectivity was changed from 0.0004 mmscfd / psi to 0.4 mmscfd / psi. A 50 bbl kick was taken to represent a severe worst case of poor kick detection and response.

Other input data in the simulator were kept the same as for group 3 simulations. After penetrating into the high pressure zone at 4500 ft, kicks were identified by an increase in the return flow-rate. Drilling was continued to 4540 ft in underbalanced condition until a 50 bbl gas kick was taken into the wellbore, and thereafter, the well control action was initiated. Only the ‘apply back pressure’ and ‘shut-in’ were simulated because the ‘increase flow rate’ option was proven unsuccessful for this well geometry in the previous cases.

6.6.1 Increase Back Pressure – Case 2B

An increasing back pressure was applied with the choke after a gas kick of 50 bbl was taken in the well, and the decreasing return flow rate was monitored. Immediately after equalizing the return flow rate with the pump rate at 91 minutes, control was switched over to maintain constant drillpipe and bottomhole pressures by adjusting the choke. Figure 6.27 shows the time-based plot of the return flow rate, pump rate, choke pressure, drillpipe pressure, choke opening and bottomhole pressure from 80 to 125 minutes. In fact, the drillpipe pressure continued to gradually decrease, and the choke opening had to be continuously reduced in an attempt to keep the drillpipe pressure constant. Consequently, the return flow rate also continued to decrease implying a higher rate of lost returns. By 99 minutes into the simulation, the choke was completely closed, but the drillpipe pressure continued to decrease.

The simulation was continued to 309 minutes with total losses to study the well behavior during gas migration while pumping into the shut-in well by monitoring the changes in the drillpipe, choke and bottomhole pressures. Figure 6.28, 6.29 and 6.30 show the composite plots of choke pressure, drillpipe pressure, bottomhole pressure, choke opening, return flow rate and the pump rate from 125 to 170 minutes, 170 to 225 minutes and 225 to 309 minutes respectively. The choke pressure increased continuously signifying gas migration effect and accumulation in the casing drillpipe annulus. The choke pressure at the end of simulation was about 1830 psi. The bottomhole pressure declined until about 125 minutes and then stayed nearly constant at 2767 to 2832 psi, which is less than the pore pressure at the kick zone.

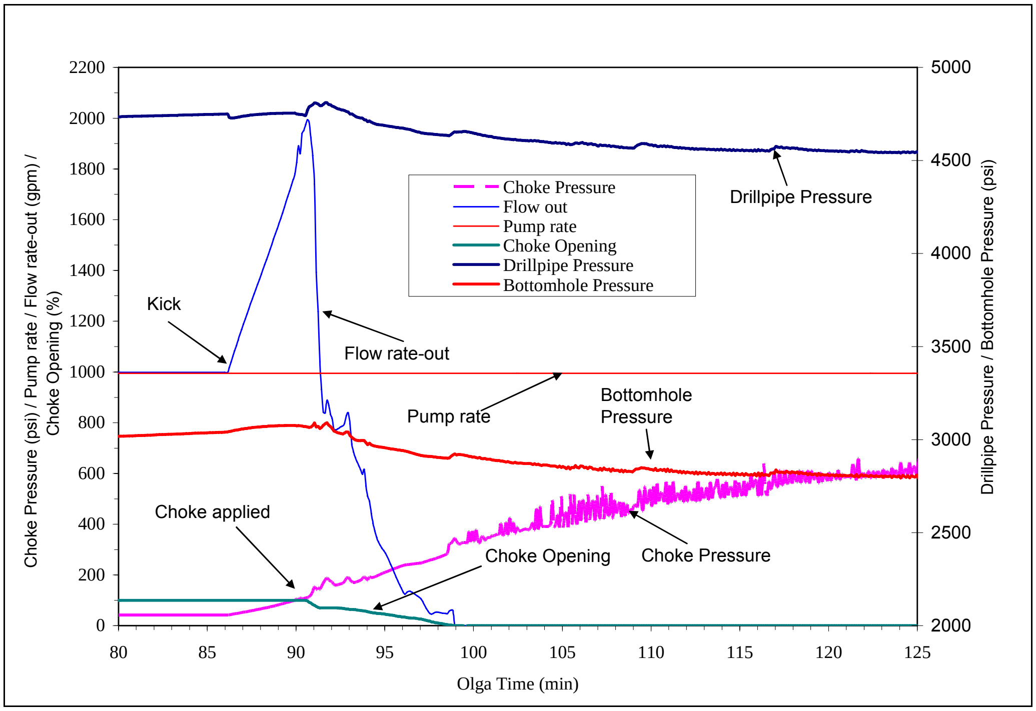

Figure 6.27: Well behavior versus time (80 to 125 minutes)
for well-z, group-4, case-2B - back pressure

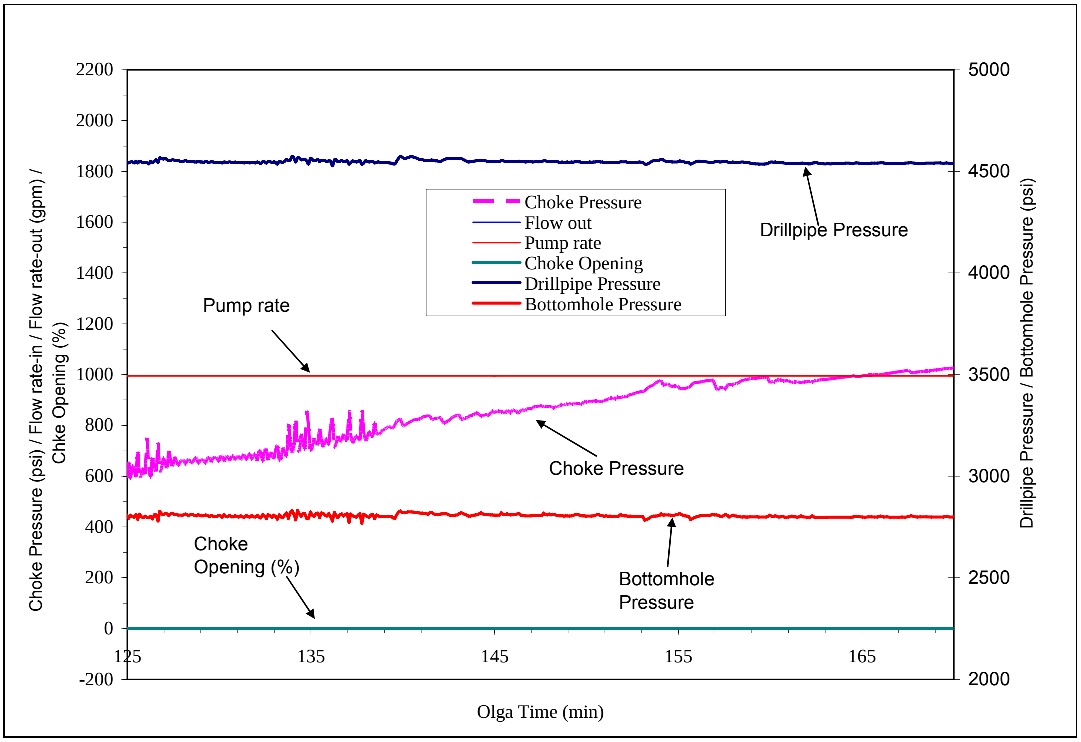

Figure 6.28: Well behavior versus time (125 to 170 minutes)
for well-z, group-4, case-2B - back pressure

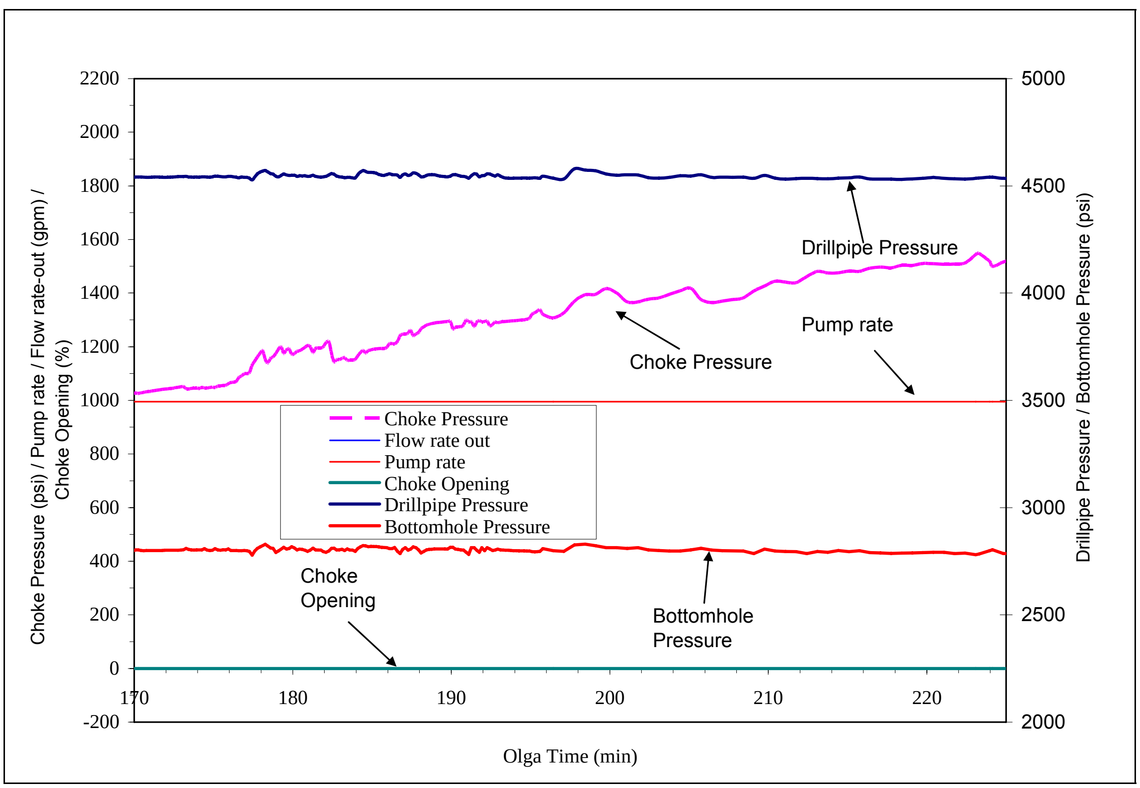

Figure 6.29: Well behavior versus time (170 to 225 minutes)
for well-z, group-4, case-2B - back pressure

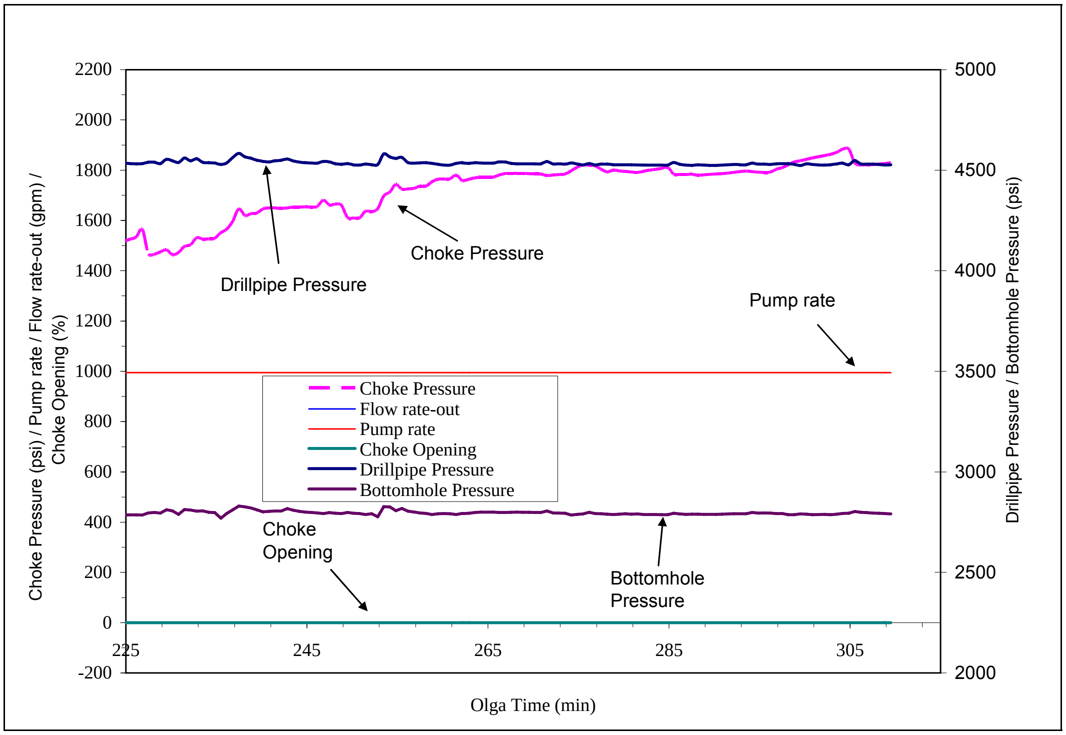

Figure 6.30: Well behavior versus time (225 to 309 minutes)
for well-z, group-4, case-2B - back pressure

This signified a continuous influx into the wellbore with complete loss of returns into the fractured formation. Drillpipe pressure also stayed nearly the same after 125 minutes. It is understood that the significant lost returns caused the bottomhole pressure and drillpipe pressure to not respond to increases in the choke pressure.

Figure 6.31 shows a plot of the pressure profiles in the well at the end of simulation. It may be seen that the wellbore pressure is less than the pore pressure at the kick zone and has exceeded the fracture pressure in shallow section of the openhole, implying that an underground blowout is in progress. The decreasing drillpipe pressure and the increasing choke pressure after the choke was completely closed are an apparent indicator of this problem. Fig 6.32 shows the formation flow profile at the end of simulation. It may be seen that the formation fluid influx and losses below the casing shoe were occurring at the end of simulation.

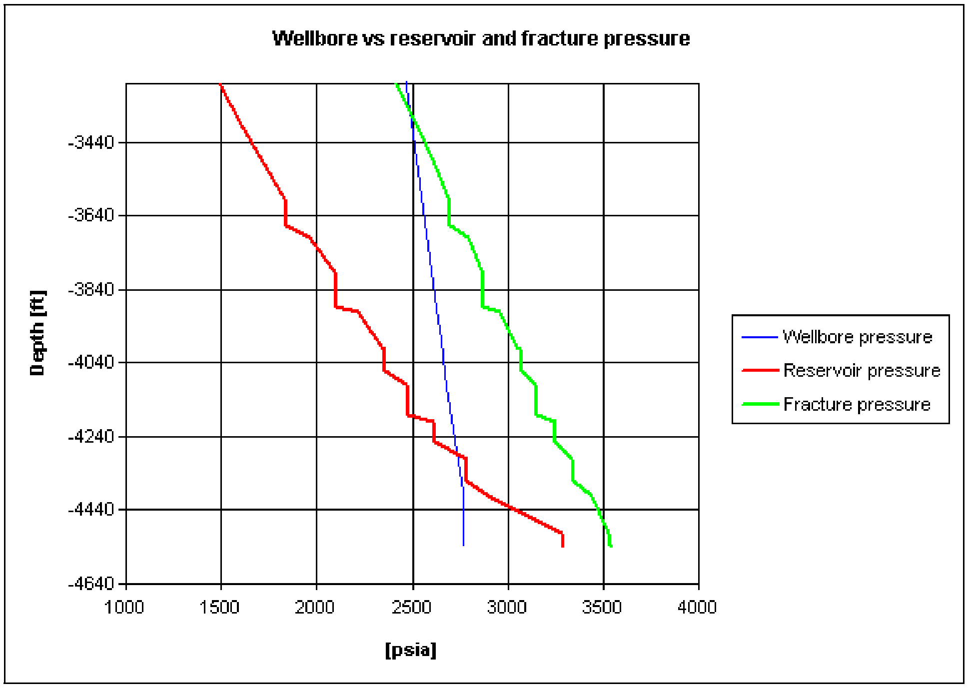

Figure 6.31: Pressure profiles at the end of simulation
for well-z, group-4, case-2B - back pressure

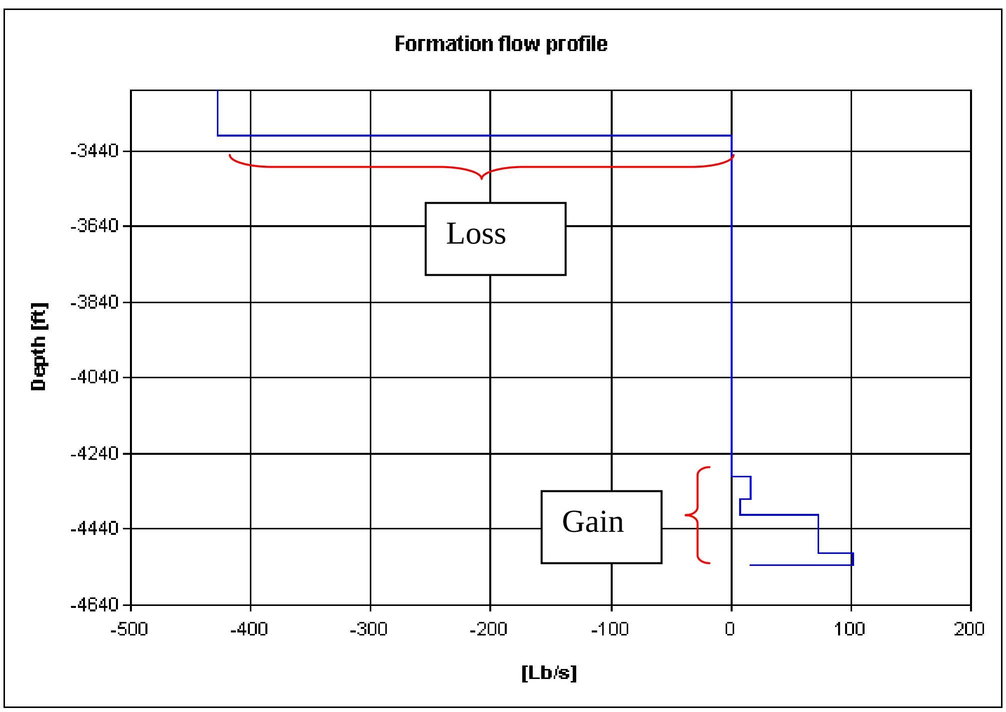

Figure 6.32: Formation fluid flow profile at the end of simulation
for well-z, group-4, case-2B - back pressure

6.6.2 Shut-in – Case 3B

Circulation was stopped after taking a 50 bbl kick, and the well was shut-in. The changes in the choke pressure and the drillpipe pressure were monitored during the prolonged shut-in period to determine whether shutting-in would stop formation flow and whether subsurface conditions could be diagnosed using only surface pressures.

The simulation was ended at 295 minutes. Figure 6.33, 6.34, 6.35 and 6.36 show the composite plots of drillpipe, choke and bottomhole pressures from 80 to 125 minutes, from 125 to 170 minutes and 170 to 215 minutes and from 215 to 295 minutes respectively.

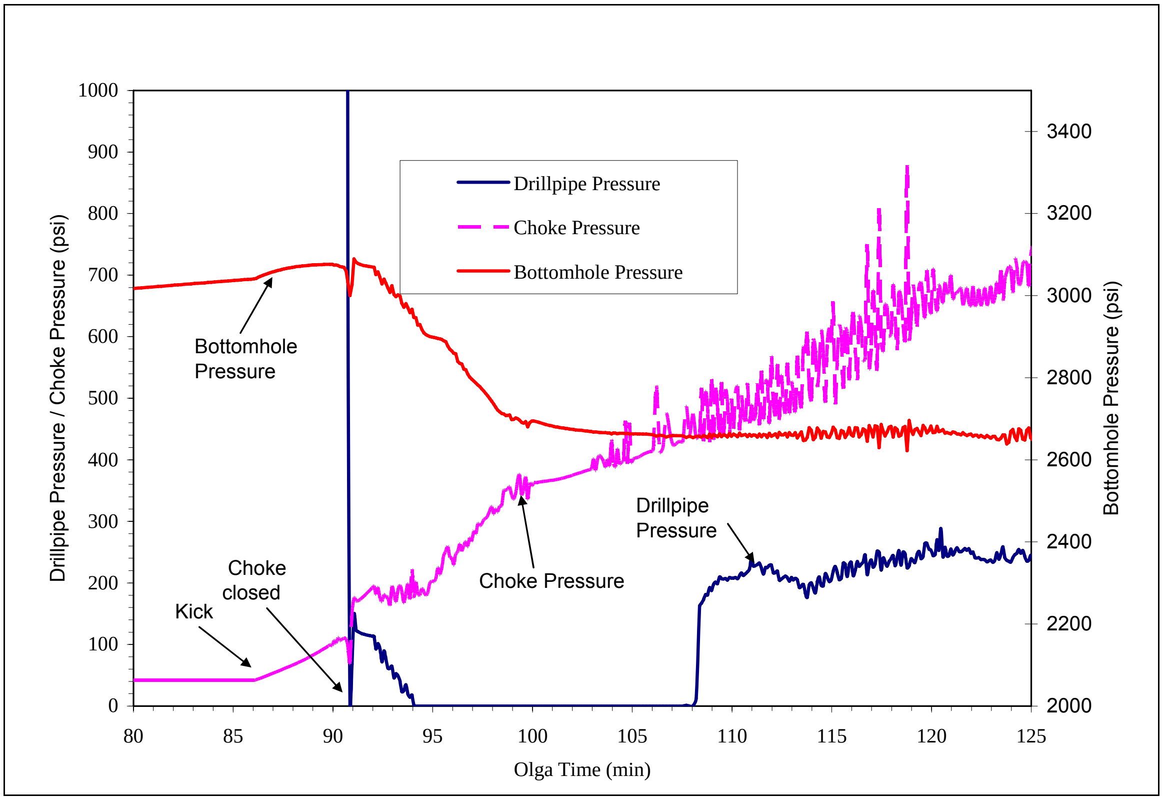

Figure 6.33: choke pressure, bottomhole pressure and drillpipe pressure from 80 to 125 minutes for well-z, group-4, case-3B - shut-in

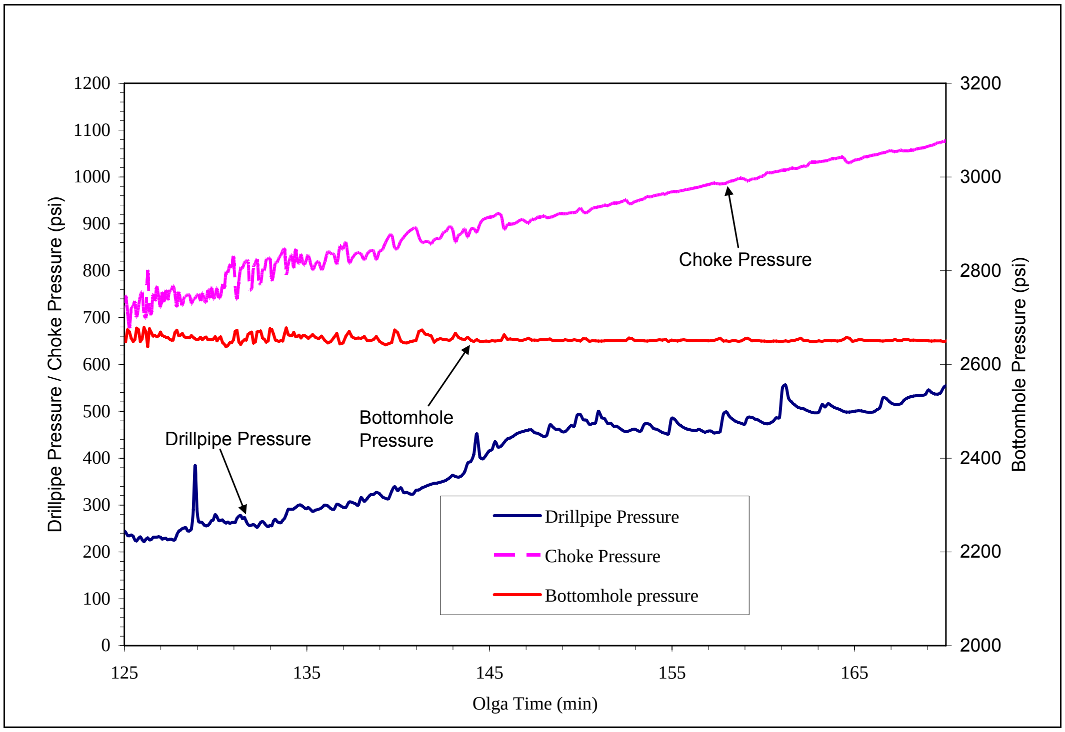

Figure 6.34: Choke pressure, bottomhole pressure and drillpipe pressure from 125 to 170 minutes for well-z, group-4, case-3B - shut-in

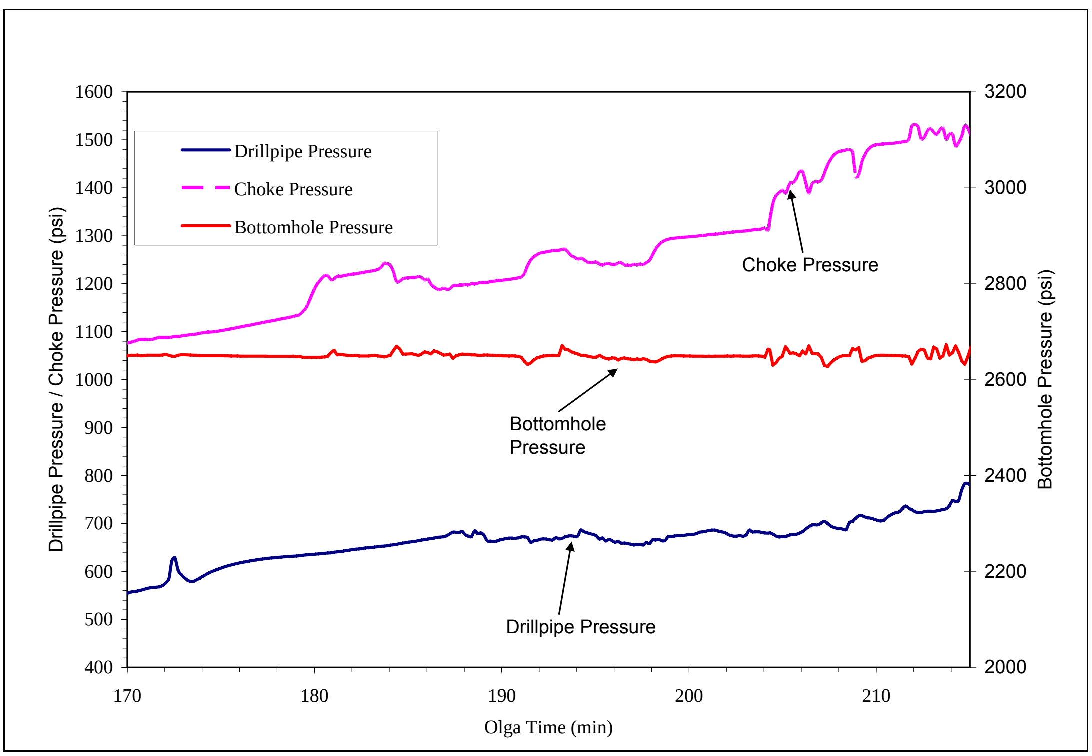

Figure 6.35: Choke pressure, bottomhole pressure and drillpipe pressure from 170 to 215 minutes for well-z, group-4, case-3B - shut-in

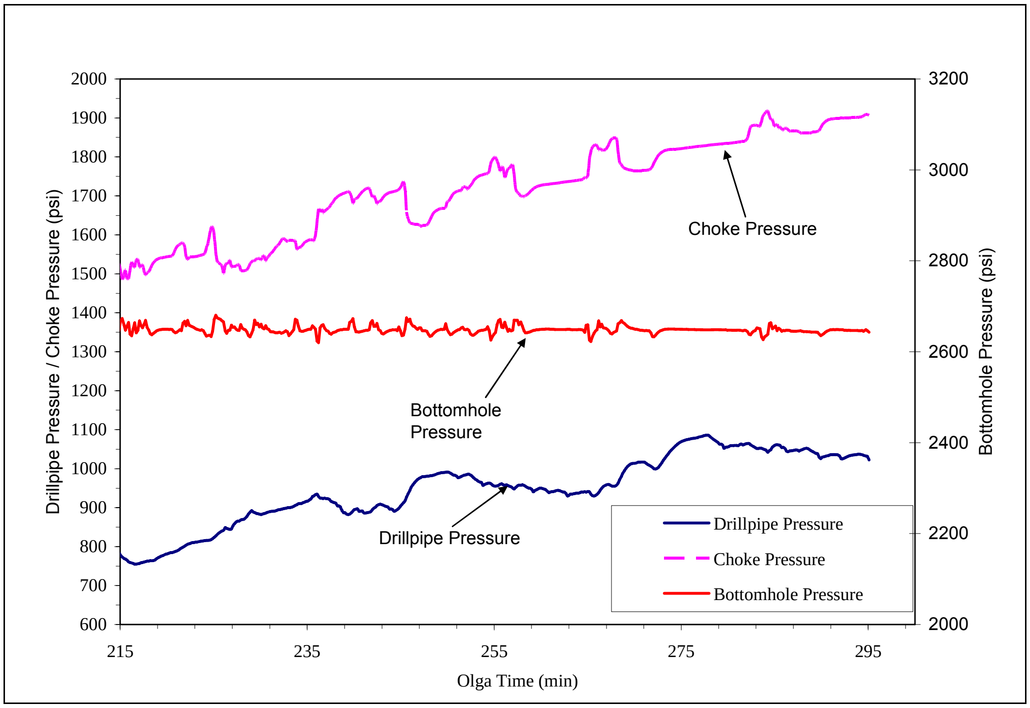

Figure 6.36: Choke pressure, bottomhole pressure and drillpipe pressure from 215 to 295 minutes for well-z, group-4, case-3B - shut-in

It may be seen that the choke pressure had continuously increased during the gas migration after the shut-in at 91 minutes. The choke pressure at the end of simulation had increased to about 1900 psi. The bottomhole pressure decreased rapidly initially probably due to the loss of the hydrostatic pressure due to heavy losses in the fracture and then remained essentially constant from about 110 minutes until the end of simulation. The bottomhole pressure was always less than the pore pressure during the shut-in period implying a continuous influx into the wellbore. After the shut-in, the drillpipe pressure was zero from about 94 to 108 minutes of the simulation although the choke pressure was rising during this period. This corresponded to the time when the bottomhole pressure was decreasing. Thereafter, the drillpipe pressure followed an increasing trend until the end of simulation, whereas the bottomhole pressure stayed nearly constant.

It seems that after the well was shut-in, the fluid level in the drillpipe fell due to the bottomhole pressure being less than the hydrostatic pressure in the drillpipe. Once the drillpipe hydrostatic pressure equalized with bottomhole pressure, gas could “swap” with mud falling out of the drillpipe. The increasing drillpipe pressure after 110 minutes is evidently due to gas migration. The zero drillpipe pressure after the well was shut-in is strong evidence that the bottomhole pressure was less than it was while drilling, indicating a reduction due to lost returns, formation fluid unloading the annulus or both. The rising choke pressure is indicative that low density fluids were migrating into and filling the annulus. The combination is a strong indication of simultaneous formation feed-in and lost returns.

Figure 6.37 shows the liquid holdup profile at the end of simulation, which suggests a continuous influx into the wellbore as the liquid holdup at the kick zone was only about 5 percent. Figure 6.38 presents the formation flow profile at the end of simulation, and it can be seen that simultaneous losses and kick feed-in were taking place in the well. Figure 6.39 shows the pressure profiles at the end of simulation. It can be seen that the wellbore pressure at the kick zone was less than the pore pressure and the wellbore pressure has exceeded the fracture pressure at the shallower section of the openhole.

6.6.3 Summary Discussions on Group 4 Simulations

Both the ‘apply back pressure’ and the ‘shut-in’ options were ineffective in these simulations with larger kicks and higher fracture injectivity. In both cases, there was continuous influx into the wellbore and continuous downhole losses in the openhole below the casing shoe, i.e. an underground blowout.

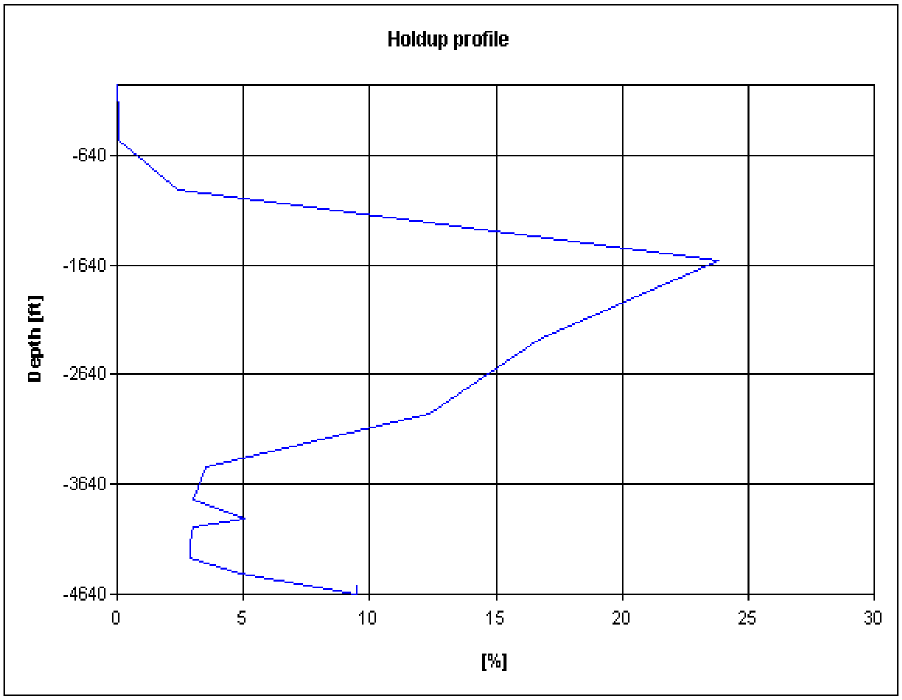

Figure 6.37: Liquid holdup profile at the end of simulation for well-z, group-4, case-3B - shut-in

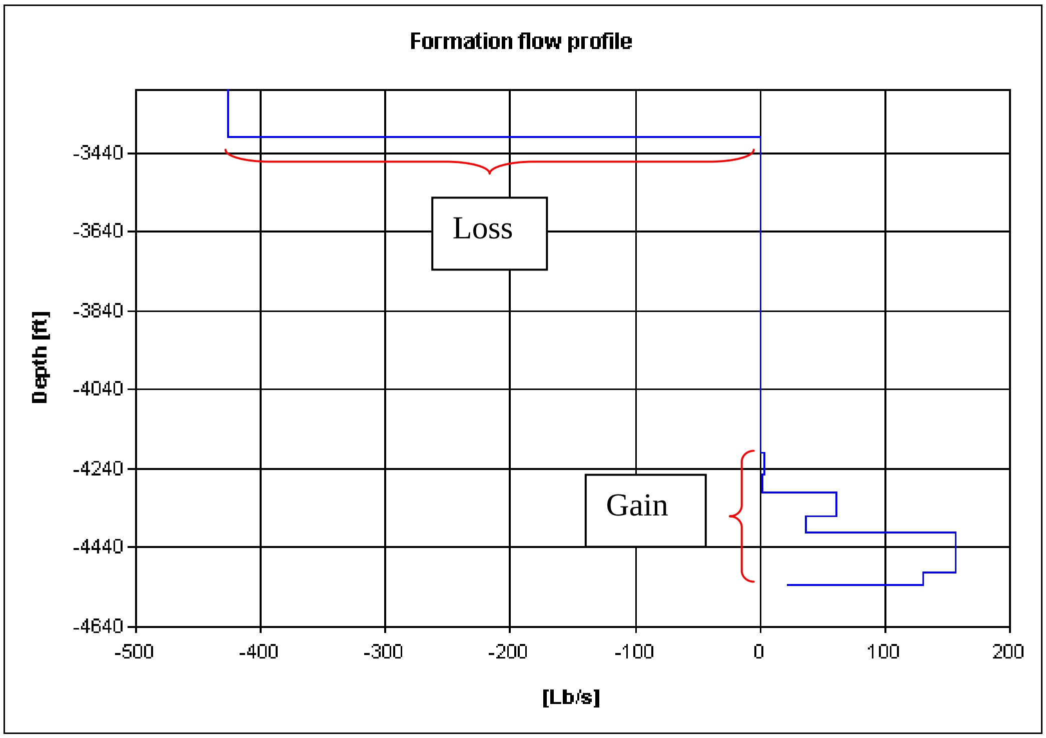

Figure 6.38: Formation flow profile at the end of simulation for well-z, group-4, case-3B - shut-in

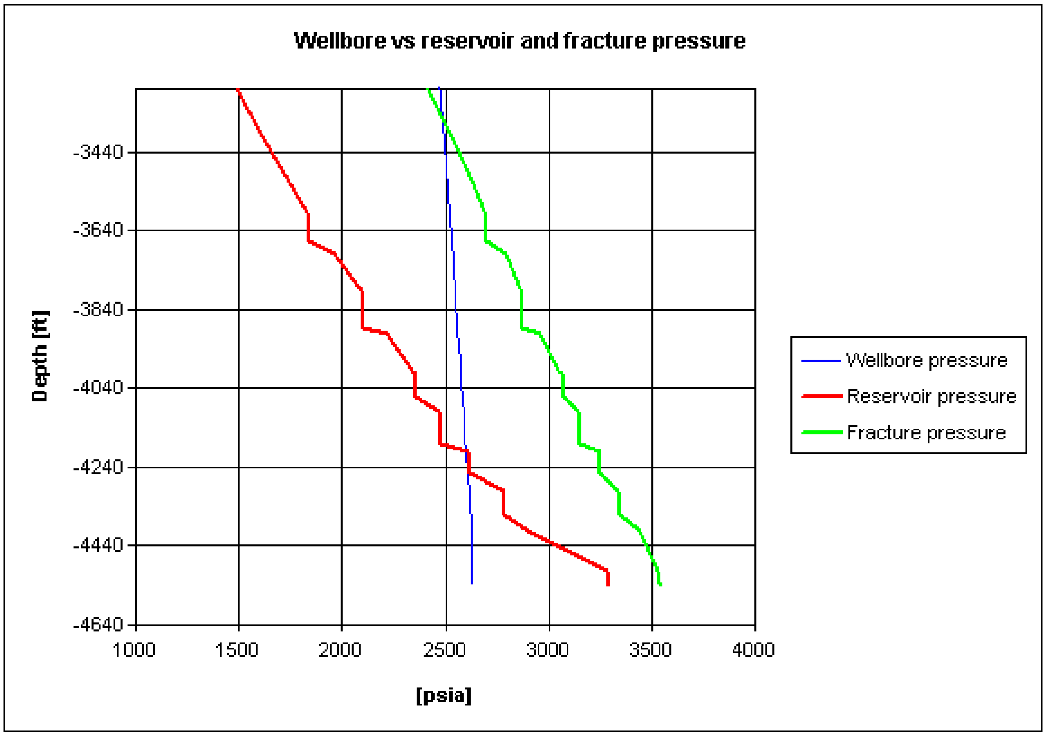

Figure 6.39: Pressure profiles at the end of simulation
for well-z, group-4, case-3B - shut-in

This contrasts with the group 3 simulations where formation influx was stopped by either option. The major difference is the higher, 0.4 mmscfd / psi injectivity at the shoe.

The back pressure case required the choke to be completely closed in order to try to keep the bottomhole pressure constant to stop the influx. Consequently, all of the mud pumped thereafter, almost 5000 bbl during this simulation was lost downhole.

The 'shut-in' option lost much less mud because no mud was pumped after shutting-in and less than 1400 bbl was in the well before losses began. However, the shut-in option does not impose much bottomhole pressure as the back pressure option, and therefore allowed a somewhat higher formation feed-in rate as seen when comparing Figure 6.38 and 6.32.

There are also differences in the ability to identify failure to prevent formation feed-in and to identify lost returns when using these responses. Loss of returns becomes evident fairly quickly in the ‘apply back pressure’ case because there are no returns once the choke is closed. The failure to stop formation feed-in is less distinctive but could be inferred from the drillpipe pressure being less, by about 100 psi in this case, than when drilling with the same pump rate. Diagnosis of sub-surface conditions after shut-in is complicated by use of a drillstring float because drillpipe pressure can not be read directly. Bumping the float to check shut-in drillpipe pressure versus time is necessary to identify the decrease in bottomhole pressure and the divergence between drillpipe and casing pressure that are evidence of an underground blowout.

6.7 Simulation Results Group 5

Four simulations were run in this group to study the effectiveness of the ‘apply back pressure’ and the ‘shut-in’ options for controlling a small volume of kick with high fracture injectivity at the shoe. The purpose of these simulations was to compare the results with group 4 simulations where higher volume kicks were taken and simultaneous loss and formation feed-in could not be controlled. A specific goal was to investigate whether either method might be more successful if the kick was identified more quickly and the kick volume was small. All input data in these simulations were same as the group 4 simulations except kick size. The well was drilled into the over-pressure section and after the kick was identified, drilling continued until a 5.5 bbl kick was taken into the wellbore, and thereafter, the well control actions were initiated.

6.7.1 Increase Back Pressure - Case 2C

Back pressure was gradually applied by reducing the choke size after taking a 5.5 bbl gas kick into the wellbore, and the return flow rate was monitored. The return flow-rate gradually decreased to approximately the level of the pump rate. Therefore, beginning at

90 minutes the choke was adjusted to keep the drillpipe pressure constant assuming that the influx into the wellbore had been stopped. However, the drillpipe pressure could not be maintained and decreased while the choke pressure was increased and the return flow rate decreased. The bottomhole pressure therefore also decreased gradually. The choke opening was continuously reduced to apply more back pressure in an attempt to keep the drillpipe pressure constant until it was completely closed at 97 minutes. The simulation was continued until 180 minutes with total losses to study the trend of the choke, drillpipe and the bottomhole pressures. Figure 6.40 and 6.41 show the composite plots of choke pressure, drillpipe pressure, bottomhole pressure, choke opening, return flow rate and the pumping rate from 80 to 125 minutes and 125 to 180 minutes respectively.

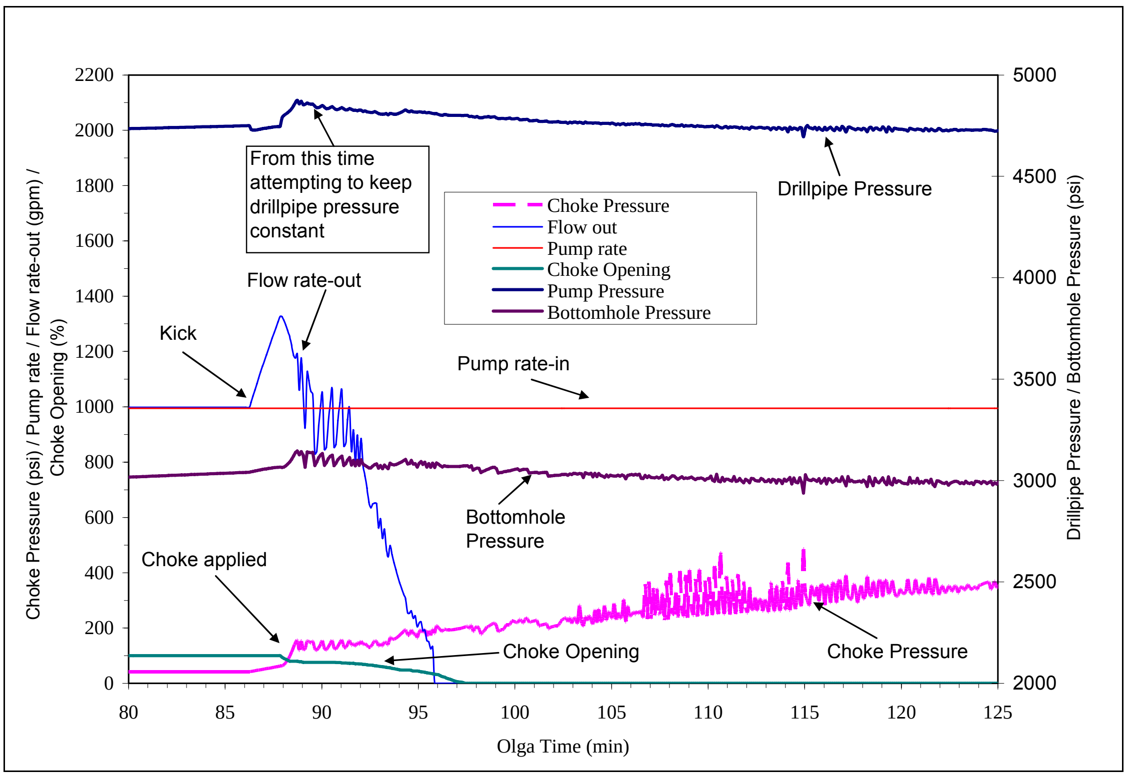

Figure 6.40: Well behavior versus time (80 to 125 minutes)
for well-z, group-5, case-2C - back pressure

It may be seen that the choke pressure increased continuously after the choke was closed probably due to the effect of migration above the casing shoe. The choke pressure at the end of simulation was about 800 psi. The bottomhole pressure after following an initial decline trend stayed nearly constant at about 3000 psi, which was less than the pore pressure of the kick zone. This implied a continuous influx from the kick zone into the wellbore with complete loss of returns into the fractured formation.

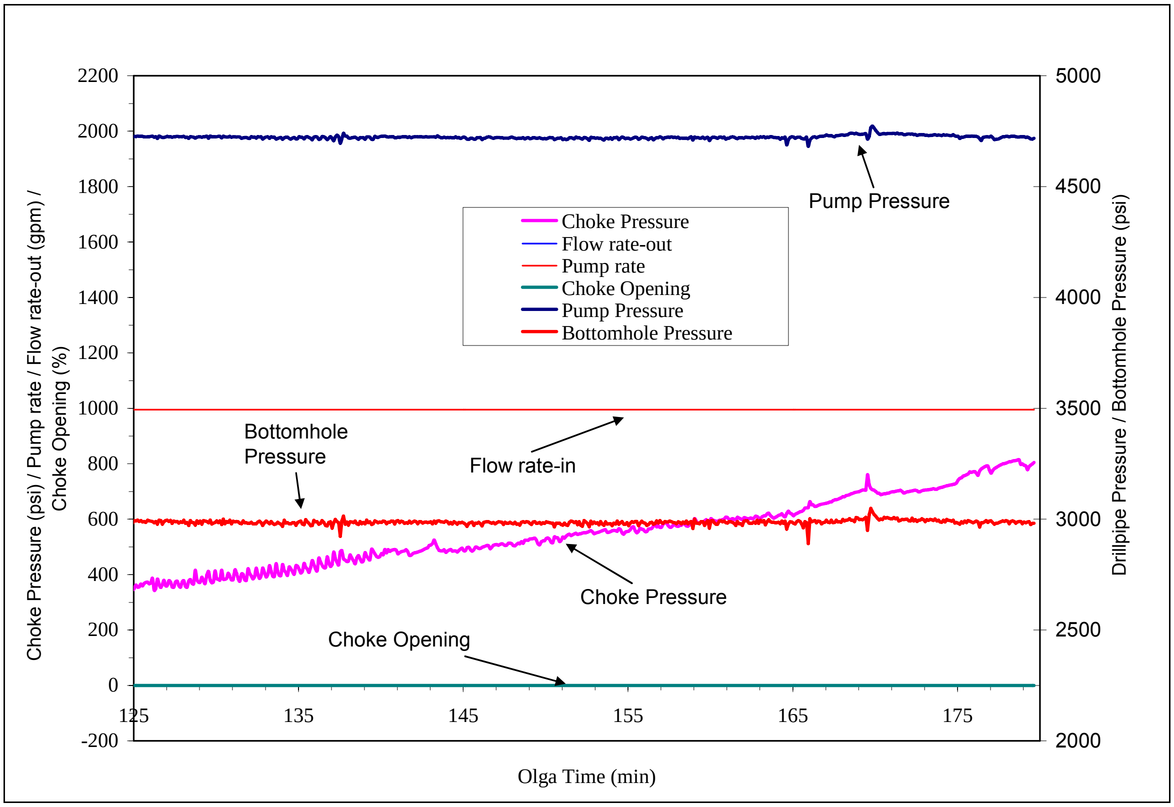

Figure 6.41: Well behavior versus time (125 to 180 minutes)
for well-z, group-5, case-2C - back pressure

Figure 6.42 shows the liquid holdup profile at the end of simulation. It may be seen that the liquid hold up at the kick zone is about 70 percent due to the influx into the wellbore. The holdup profile shows the presence of gas throughout the well and reinforces the interpretation that simultaneous feed-in and losses are occurring and an underground blow out has begun.

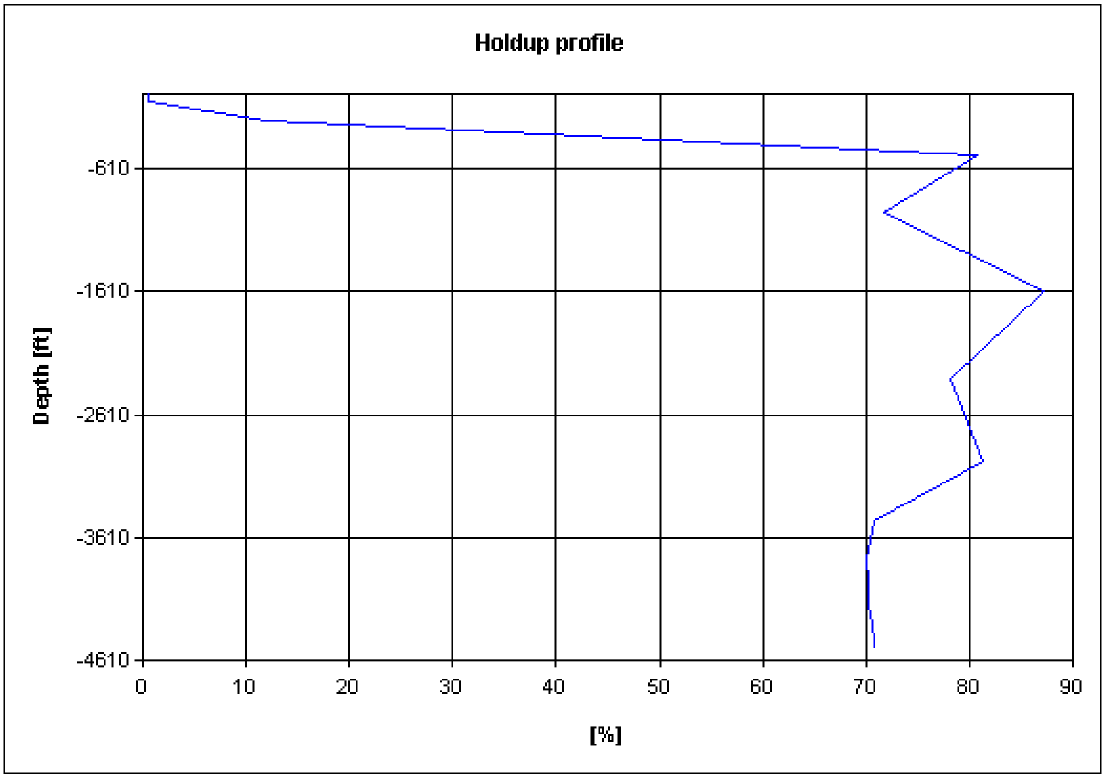

Figure 6.42: Liquid holdup profile at the end of simulation
for well-z, group-5, case-2C - back pressure

6.7.1.1 Increase Back Pressure - Case 2C-Alt-1

This simulation is a modification of the previous simulation. In this simulation, the choke was adjusted to keep the flow rate-out equal to the flow rate-in for a longer period instead of trying to keep the drillpipe pressure constant once the flow rate-out equaled flow-in. In an intact wellbore, this would typically cause excessive wellbore pressure and risk of lost returns. Although this is not considered a correct approach, it could be applied when the drillpipe pressure cannot be maintained and is often considered as prevention of additional feed-in. Figure 6.43 and Figure 6.44 show composite plots of choke pressure, drillpipe pressure, bottomhole pressure, flow rate-in, flow rate-out, gas flow-out and choke opening of this simulation from 80 to 125 minutes and from 125 to 180 minutes, respectively.

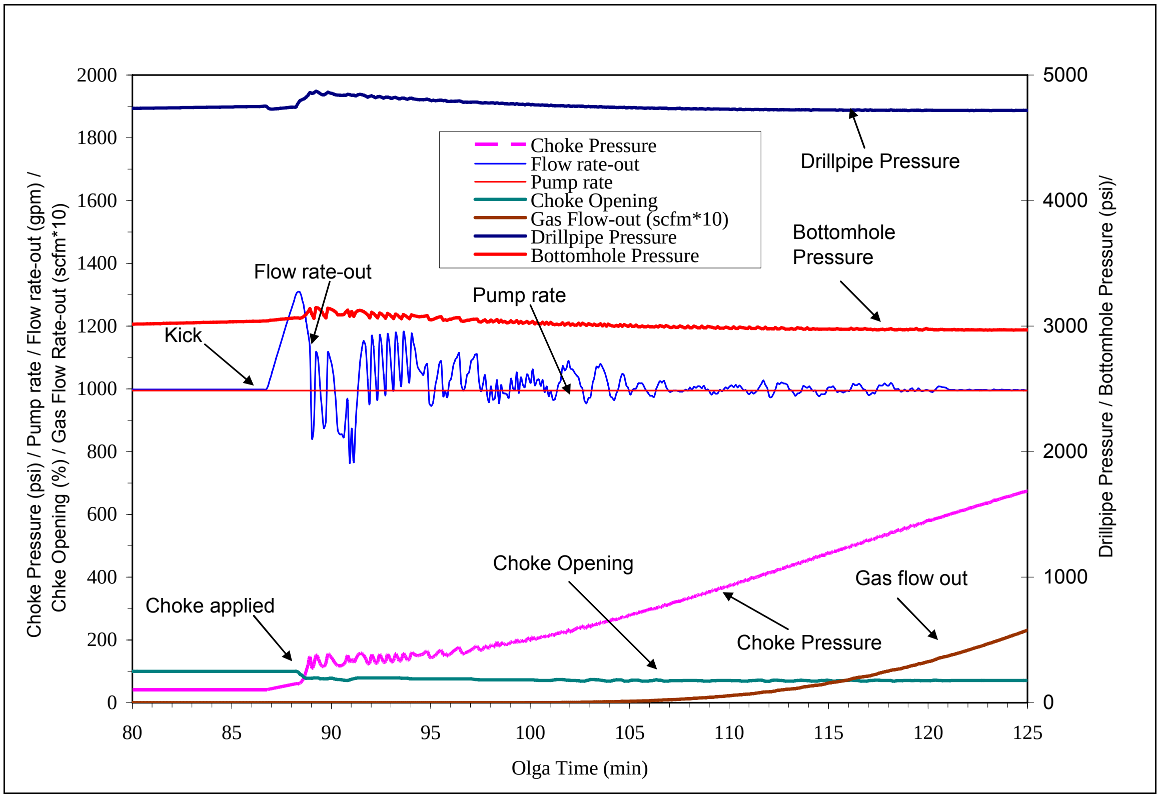

Figure 6.43: Well behavior versus time (80 to 125 minutes) for well-z, group-5, case-2C-Alt-1 - back pressure

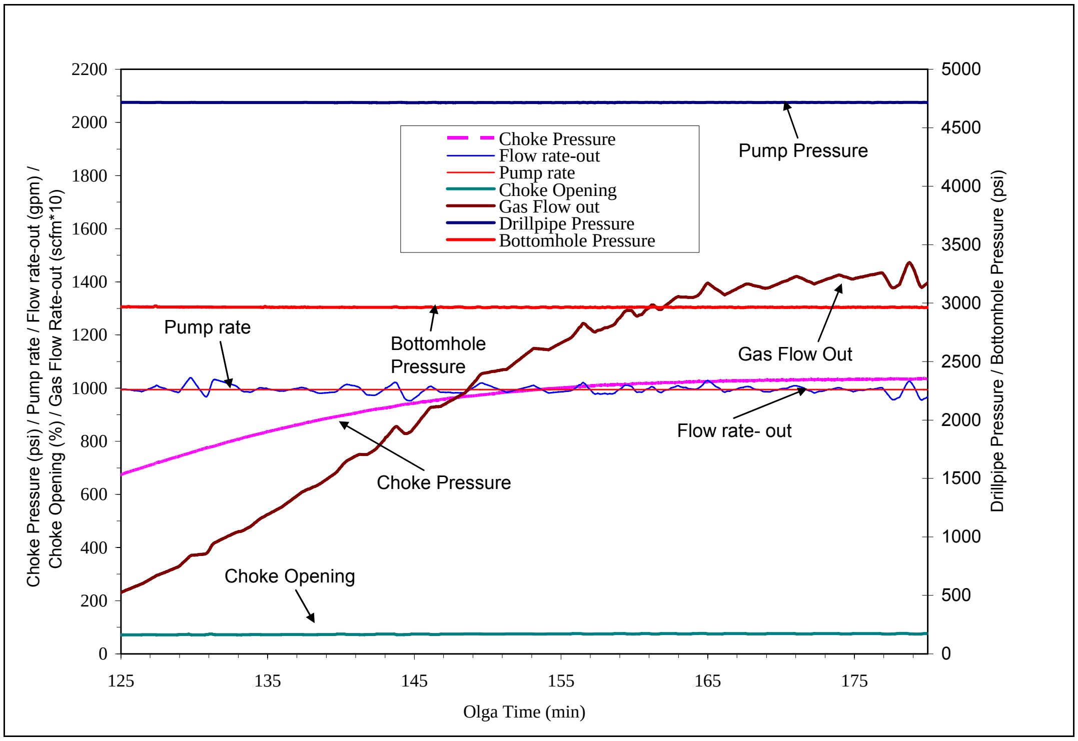

Figure 6.44: Well behavior versus time (125 to 180 minutes) for well-z, group-5, case-2C-Alt-1 - back pressure

It may be seen that, the gas flow rate at the surface increased to 14188 scfm (20.43 mmscfd) by the end of simulation. After an initial decline, both the bottomhole and the drillpipe pressures were nearly constant, indicating an essentially steady-state condition.

Figure 6.45 and Figure 6.46 show the formation flow profile and the liquid holdup profile, respectively, at the end of simulation. These plots confirm that the gas influx from the formation was still continuing at the end of simulation and that no downhole losses are occurring. Therefore, this procedure was not successful in controlling the well. However, allowing the continuous gas flow to the surface did halt the lost returns.

6.7.1.2 Increase Back Pressure - Case 2C-Alt-2

This simulation is another modification of the case 2C simulation. In this simulation, the choke was adjusted for extended period of time to keep the flow rate-out equal to flow rate-in, and thereafter at about 100 minutes, the control was switched to keep the drillpipe pressure constant. It was intended as an extended, or more cautious attempt then case 2C to define the drillpipe pressure to stop formation feed-in.

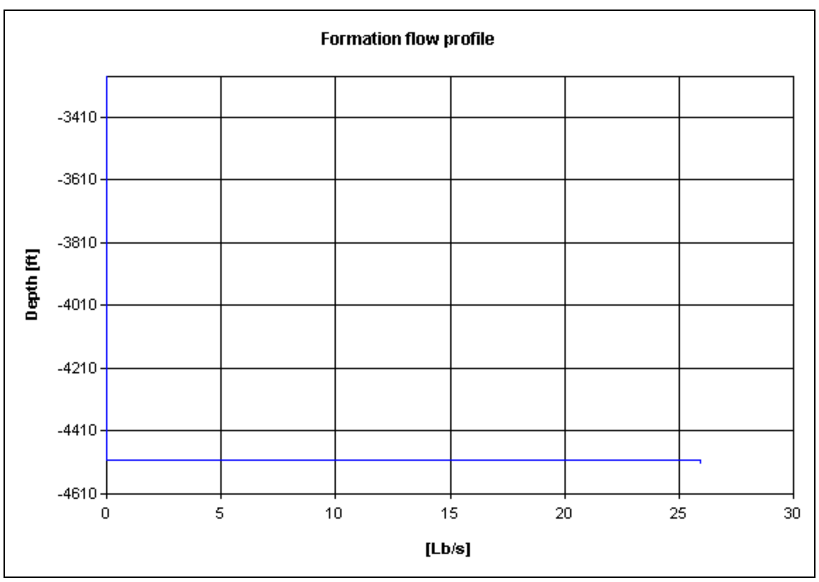

Figure 6.45: Formation fluid flow profile at the end of simulation for well-z, group-5, case-2C-Alt-1 - back pressure

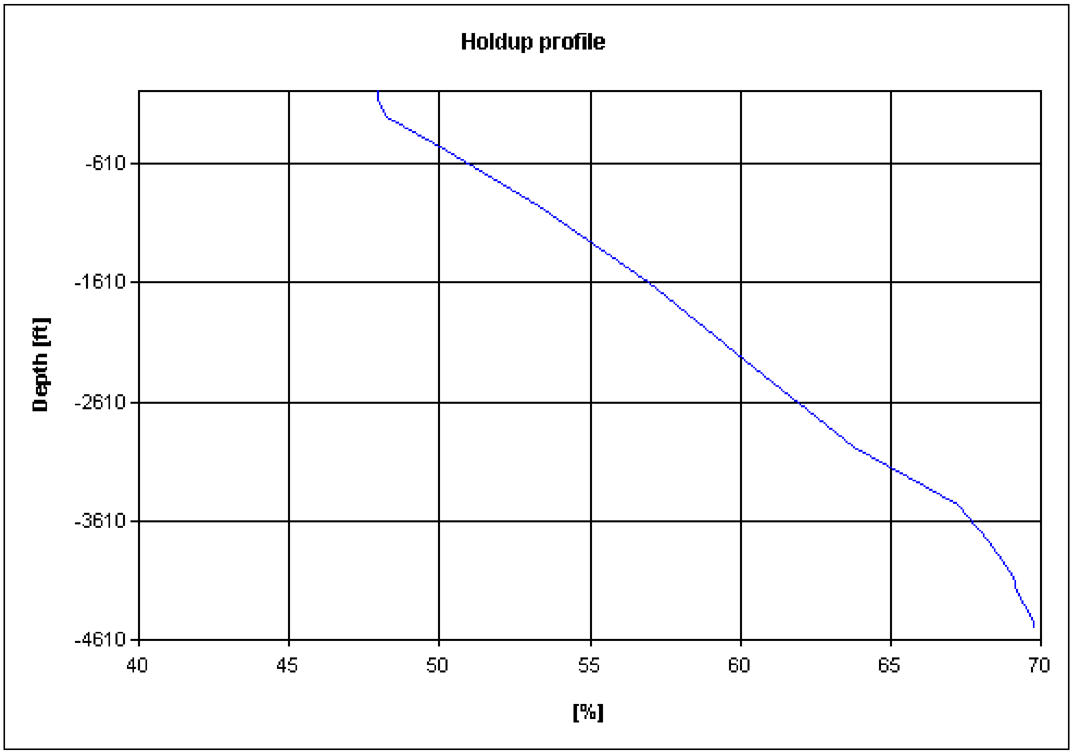

Figure 6.46: Liquid holdup profile at the end of simulation
for well-z, group-5, case-2C-Alt-1 - back pressure

Figure 6.47 and Figure 6.48 show composite time-based plots of choke pressure, drillpipe pressure, botomhole pressure, flow-in, flow-out and choke opening for this simulation from 80 to 125 minutes and 125 to 235 minutes respectively. It may be seen that the choke size had to be continuously reduced to keep the drillpipe pressure constant after 100 minutes, and finally, it was completely closed at about 114 minutes. Because of lost returns, the drillpipe pressure did not respond to increasing choke pressure. The drillpipe and the bottomhole pressures declined during the entire period from 90 minutes to 114 minutes despite reducing the choke size, presumably due to less wellbore frictional pressure due to losses. The casing pressure continued to increase with the choke closed, probably due to continued gas migration above the casing shoe, whereas, the bottomhole pressure and the drillpipe pressure were nearly constant as the well experienced total losses in the open hole below the casing shoe.

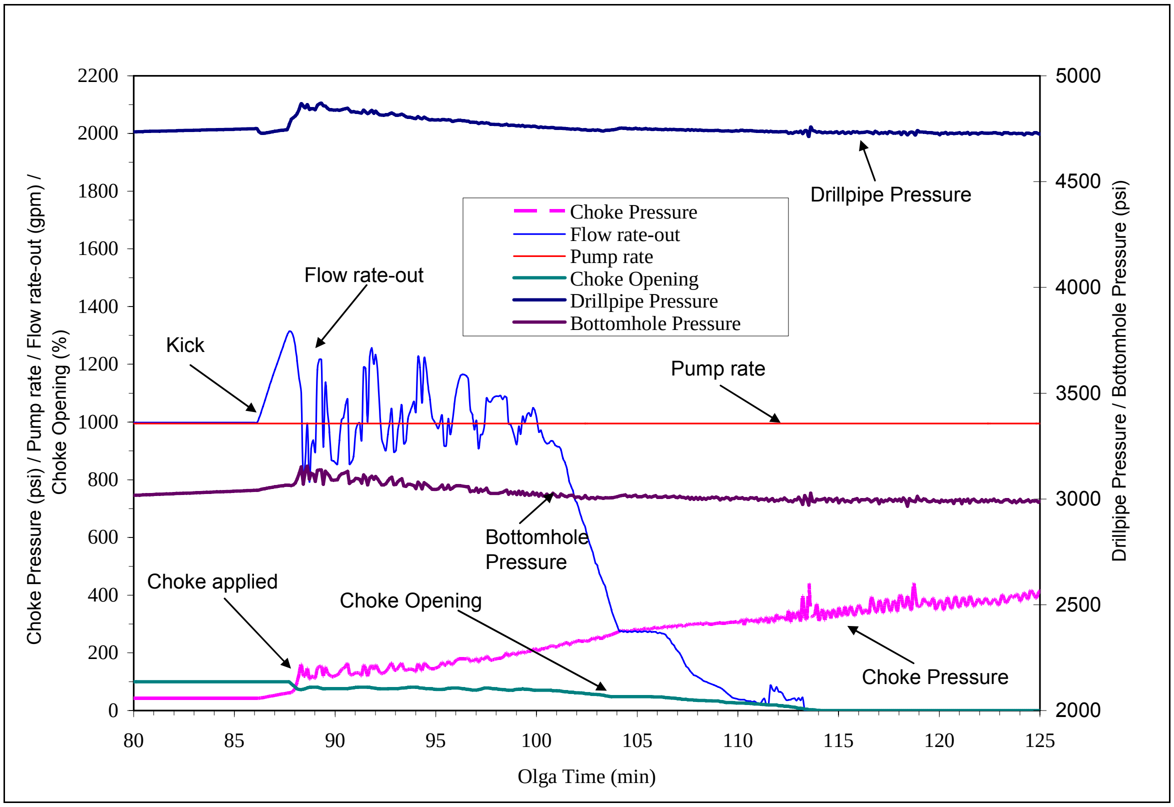

Figure 6.47: Well behavior versus time (80 to 125 minutes)
for well-z, group-5, case-2C-Alt-2 - back pressure

Figure 6.49 shows the liquid holdup profile at the end of this simulation. The liquid holdup was about 70 to 72 percent at the kick zone suggesting continuous gas influx into the wellbore. Holdup less than 100 percent throughout the wellbore indicates this influx is migrating to the surface and displacing mud from the annulus into the formation. From Figure 6.47 and Figure 6.48, it may be seen that the bottomhole pressure was always less than the pore pressure causing continuous influx into the wellbore.

6.7.2 Shut-in - Case 3C

The well was closed on choke after taking a 5.5 bbl kick into the wellbore. The changes in the choke pressure and the drillpipe pressure were monitored during a prolonged shut-in period.

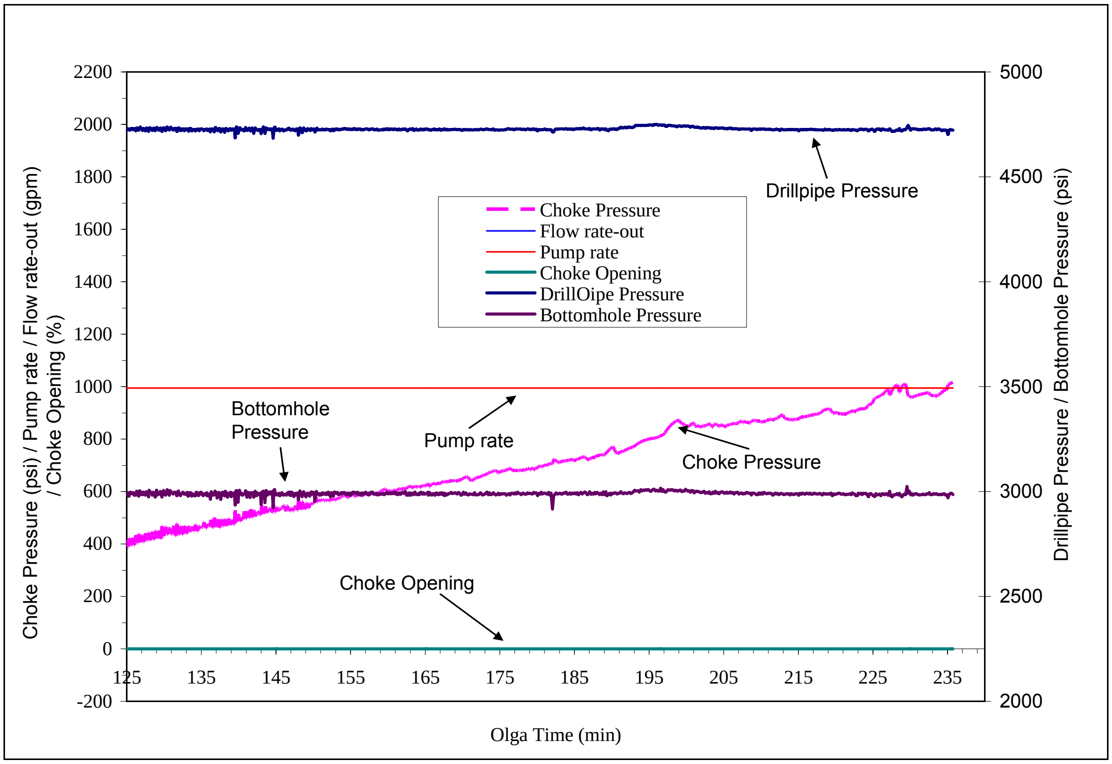

Figure 6.48: Well behavior versus time (125 to 235 minutes)
for well-z, group-5, case-2C-Alt-2 - back pressure

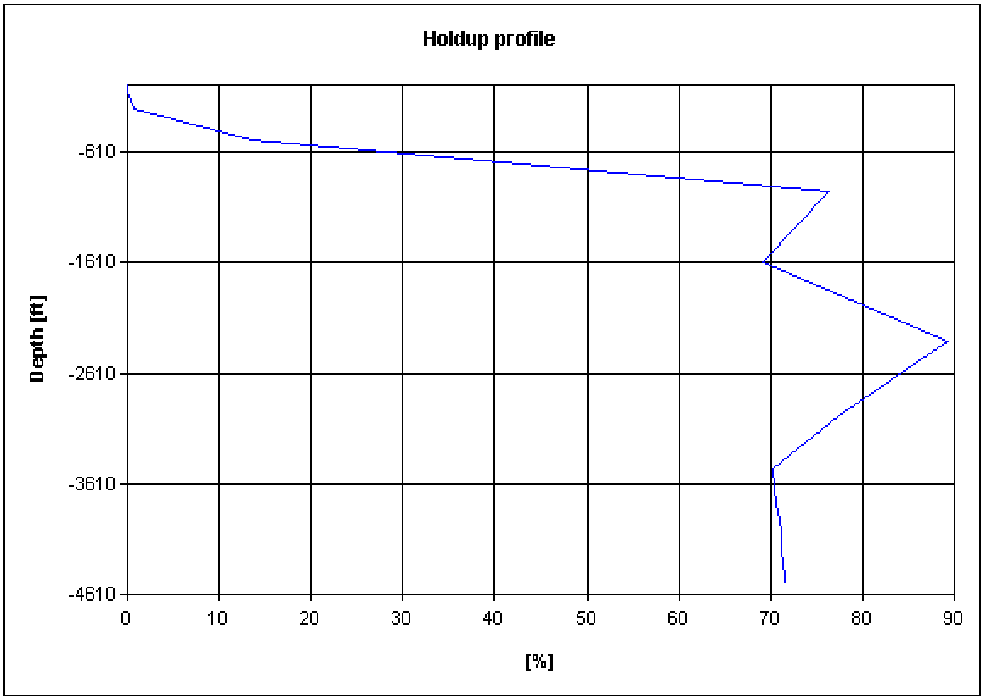

Figure 6.49: Liquid holdup profile at the end of simulation
for well-z, group-5, case-2C-Alt-2 - back pressure

The simulation ended at 180 minutes. Figure 6.50 and Figure 6.51 show the composite plots of drillpipe pressure, choke pressure and bottomhole pressures from 80 to 125 minutes and from 125 to 180 minutes respectively.

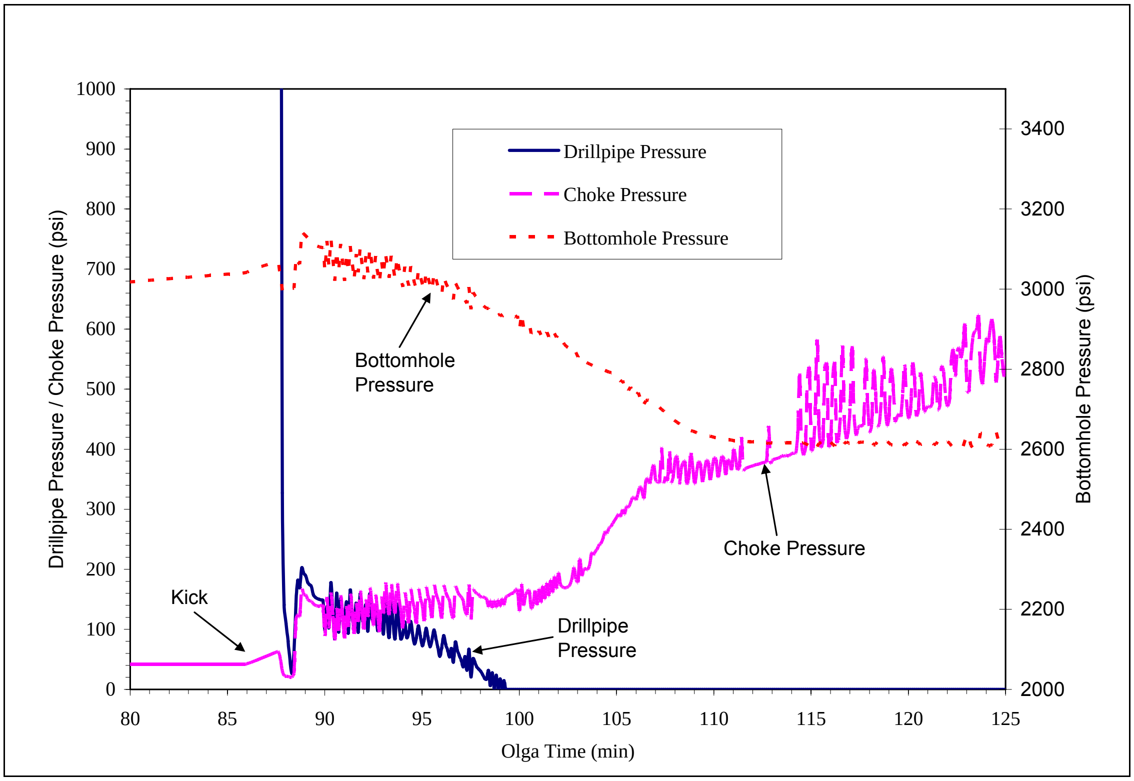

Figure 6.50: Choke pressure, bottomhole pressure and drillpipe pressure from 80 to 125 minutes for well-z, group-5, case-3C - shut-in

The choke pressure continuously increased after shut-in due to feed-in and gas migration. The choke pressure at the end of simulation had increased to about 1015 psi. The bottomhole pressure decreased initially probably due to loss of hydrostatic pressure in the annulus due to heavy downhole mud losses and then almost stabilized at about 2600 psi after about 110 minutes. The bottomhole pressure was significantly less than the pore pressure during shut-in period, implying there was a continuous influx into the wellbore.

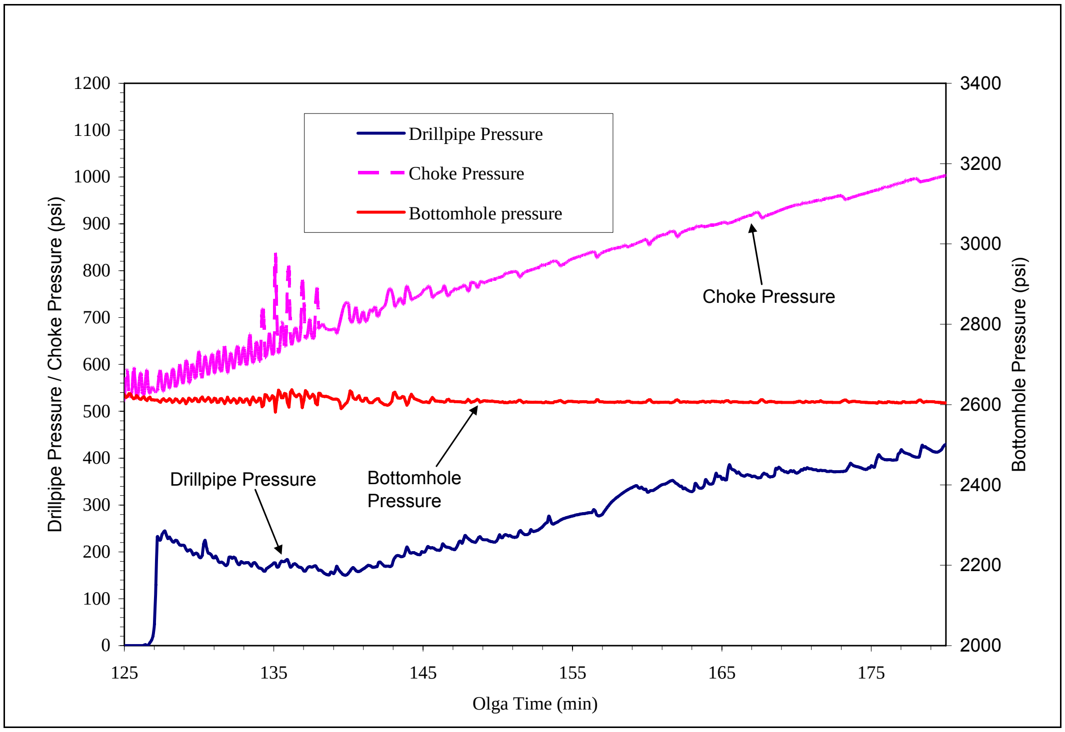

Figure 6.51: Choke pressure, bottomhole pressure and drillpipe pressure from 125 to 180 minutes for well-z, group-5, case-3C - shut-in

After shut-in, the drillpipe pressure was zero from about 99 to 125 minutes although the choke pressure was rising during this period. This corresponded to the time when the bottomhole pressure was also decreasing. Thereafter, the drillpipe pressure followed an increasing trend until the end of simulation. The similar trend of drill pipe pressure after the well was shut-in was noticed in case 3B with a bigger, 50 bbl kick. Rise of drillpipe pressure was presumably due to the migration of gas that entered into the drillpipe under the condition as described in section 6.6.2. The zero drillpipe pressure after the well was shut-in is indicative of lost return. The rising choke pressure is indicative of gas migration. Figure 6.52 shows the liquid holdup at the end of simulation. Liquid hold up in the open hole at the end of simulation was only about 5 percent implying that gas flow from the kick zone had displaced almost all of the mud from the open hole into the loss zone.

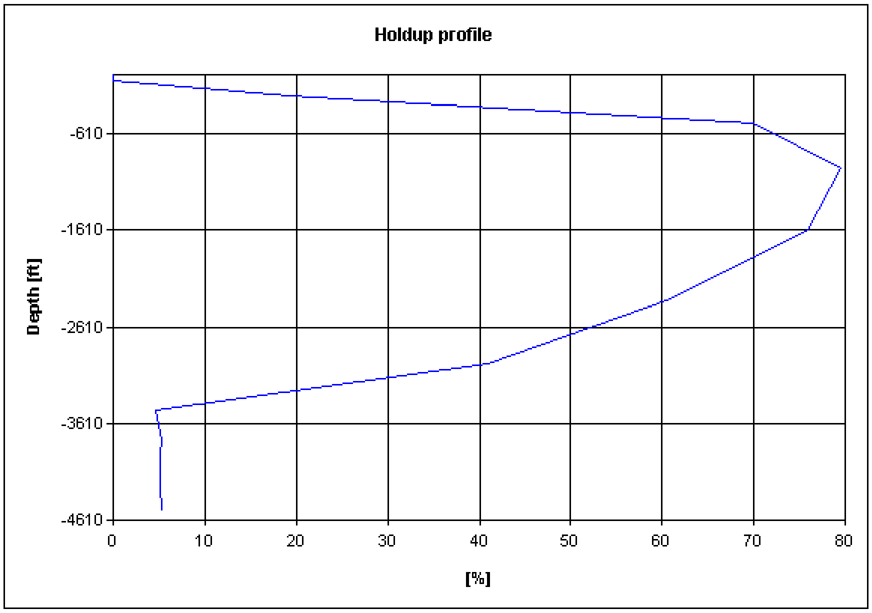

Figure 6.52: Liquid holdup profile at the end of simulation
for well-z, group-5, case-3C - shut-in

Figure 6.53 shows the formation fluid flow profile in the wellbore at the end of simulation. It shows that the gas flow from the kick zone had not been controlled and that simultaneous losses are occurring below the casing shoe. Hence, an underground blowout was in progress.

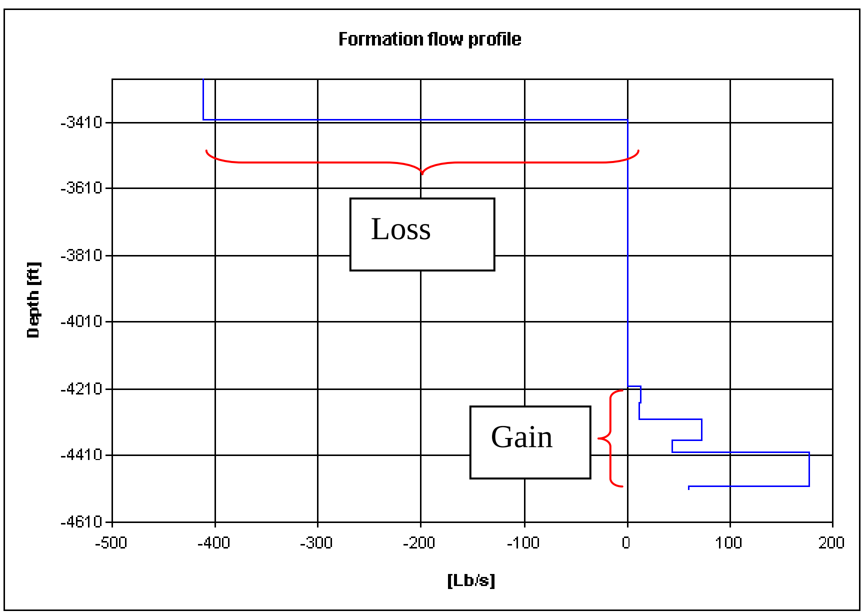

Figure 6.53: Formation fluid flow profile at the end of simulation
for well-z, group-5, case-3C - shut-in

6.7.3 Summary Discussions on Group 5 Simulations

The results and trends observed in these simulations with small kick volumes were similar to group 4 simulations with similar well conditions but a larger kick volume. The larger kick volume in the group 4 simulations resulted in higher surface pressure during kick control. Therefore, earlier kick detection and response allows more time to diagnose the failure to control the well and formulate a better response. When the fracture pressure was exceeded, the high injectivity dominated the simulation results in both groups such that the well could not be controlled with either the 'shut-in' or 'back pressure' options. For the shut-in option, the zero drillpipe pressure during the initial shut-in period is indicative of a decrease in bottomhole pressure and probable lost returns in the open hole.

For both the 'apply back pressure' and 'shut-in options, there was continuous formation influx into the wellbore, and both were therefore ineffective. The trend of increase in choke pressure after the choke was closed was similar in both options. In the 'shut-in' option, much less mud was lost compared to the 'back pressure' option with continuous circulation. Since circulation was continued even after the choke was closed in 'back pressure' reaction, the bottomhole pressure was higher than the shut-in option. This implied that the influx rate would be less in the 'back pressure' reaction than the 'shut-in' reaction. Additional analysis and comparisons are included in the following section.

6.8 Overall Summary of Well Z Simulations

A total of 14 simulations were run to develop an insight into the effectiveness of different initial reactions to a gas kick in a large size hole drilled under the CBHP method of MPD operation. The severity of the well control scenarios were varied by changing pore pressure, kick size and fracture injectivity at the casing shoe. Some simulations were run for a longer duration when formation breakdown occurred during the initial reaction to see the long term effect for comparative studies. Since keeping an intact wellbore is critically important to prevent an underground blow-out, the ability to detect formation fracture during well control is an important criteria to judge the effectiveness of initial reactions. The longer simulations were intended to evaluate whether the formation break down can be recognized by monitoring parameters such as choke pressure, drillpipe pressure, bottomhole pressure and return flow rate.

Stopping the influx by increasing the ECD with higher pumping rate was not successful for either of two simulations with kick intensities 0.49 ppge and 1.49 ppge and a small, 5.5 bbl, initial kick volume. The annular frictional pressure losses in a large annular geometry were not adequate within the limitation of pump capacity to over-balance the pore pressure. Further simulations with larger kick sizes would have even less successful and were deemed unnecessary.

Both application of 'back pressure' with a choke and 'shutting-in' the well were successful in stopping the influx for the lower kick intensity (0.49 ppge) due to keeping an intact wellbore. However, the formation fractured when these options were applied in simulations with kick intensity of 1.49 ppge due to there being almost no margin between the pore and fracture pressure gradients. Neither the 'back pressure' nor 'shut-in' reactions were successful in stopping formation feed-in under these circumstances.

The simulation results of back pressure reaction maintaining flow-out equal to flow-in for longer period show that the formation feed-in can not be stopped and an uncontrolled flow of gas at the surface may result.

In the 'shut-in' reaction, formation fracture resulted before the wellbore pressure was high enough to stop formation feed-in. A shut-in well will generally have upward migration of gas, the effect of which will be an increase in the choke pressure. In the case of simultaneous losses and feed-in, the casing pressure will also increase, usually more rapidly. Monitoring the drillpipe pressure during shut-in as an indicator of the bottomhole pressure can provide a basis for distinguishing simple migration from this more dangerous situation. In the simulations, this was done as described in section 6.6.2 because the drillpipe float was removed. In actual operations, a procedure to bump the float to check the drillpipe pressure is required.

Three different strategies of choke adjustments were considered in the applications of back pressure as a response. These were (1) to maintain the drill pipe pressure constant after quickly, for about 3 minutes, forcing flow-out equal to flow-in case 2C-Alt, (2) to try to maintain the return flow equal to flow rate-in indefinitely in case 2C-Alt-1and (3) to maintain the return flow rate equal to flow rate-in for an extended time (about 15 minutes) in case 2C-Alt-2 and then switch control to maintain the drillpipe pressure constant. These long simulations were ended when an essentially steady state condition was reached and the expected future trend of choke pressure, drillpipe pressure, and gas flow rate could be implied.

The results of the simulations where the shoe was fractured during the initial reactions are presented below in the form of flow charts to facilitate comparisons. Figure 6.54, 6.55, 6.56, 6.57 and 6.58 show the results and comparison of group-2, group-3, group-4, group-5 (case-2C and case-3C) and group-5 (case-2C-Alt-1 and case-2C-Alt-2) simulations respectively.

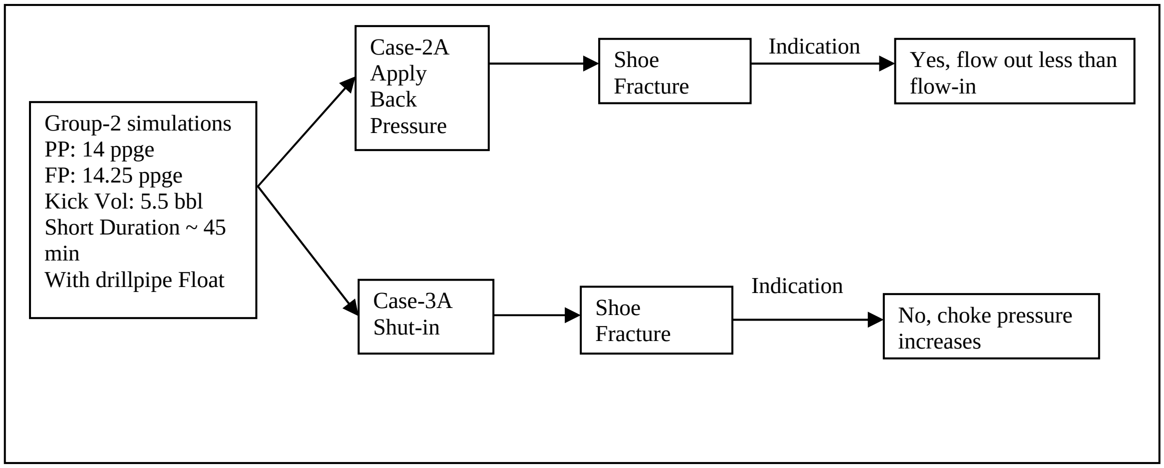

Figure 6.54: Comparison of group-2 simulations

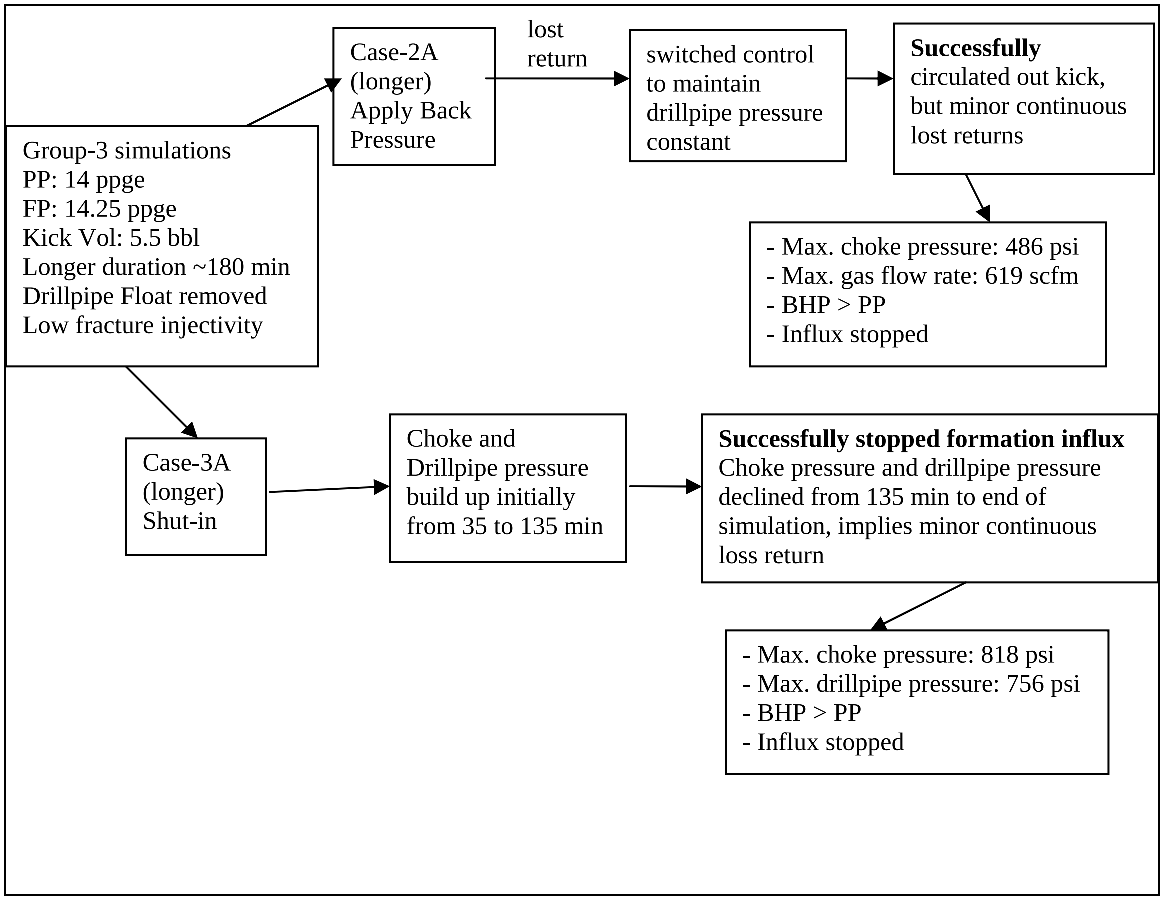

Figure 6.55: Comparison of group-3 simulations

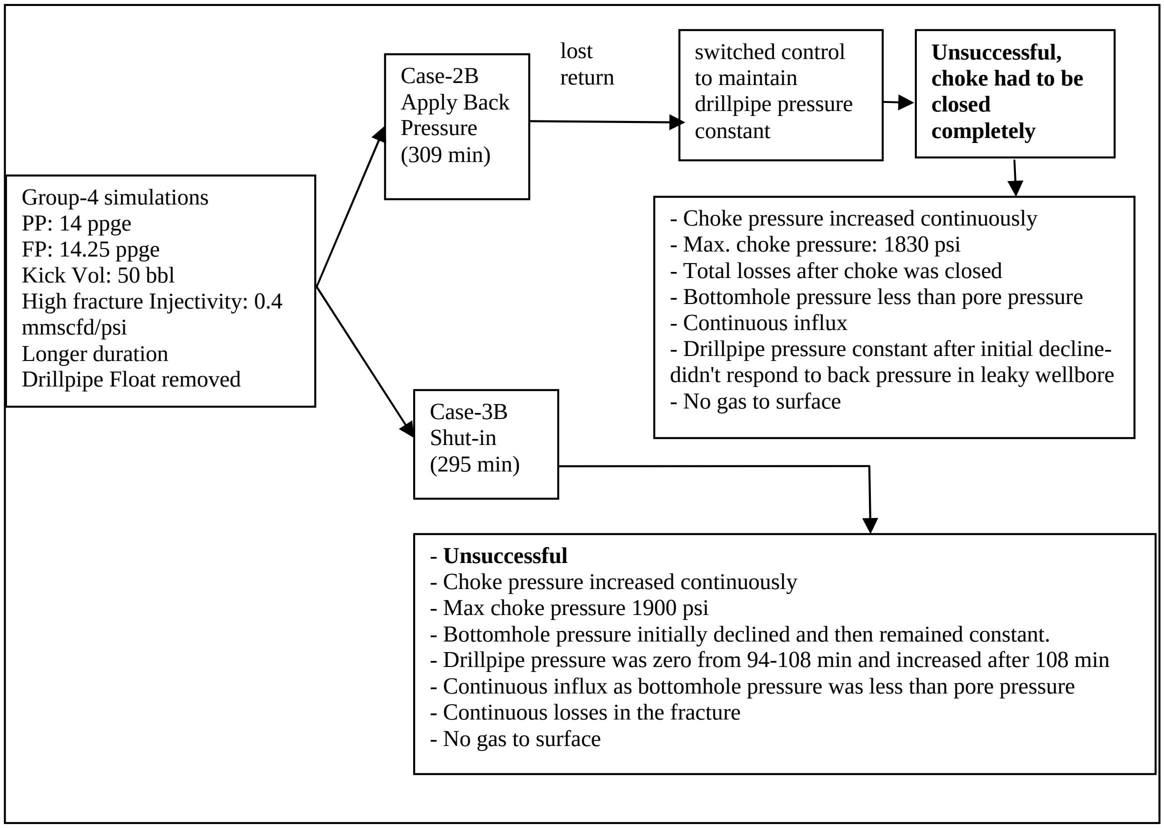

Figure 6.56: Comparison of group-4 simulations

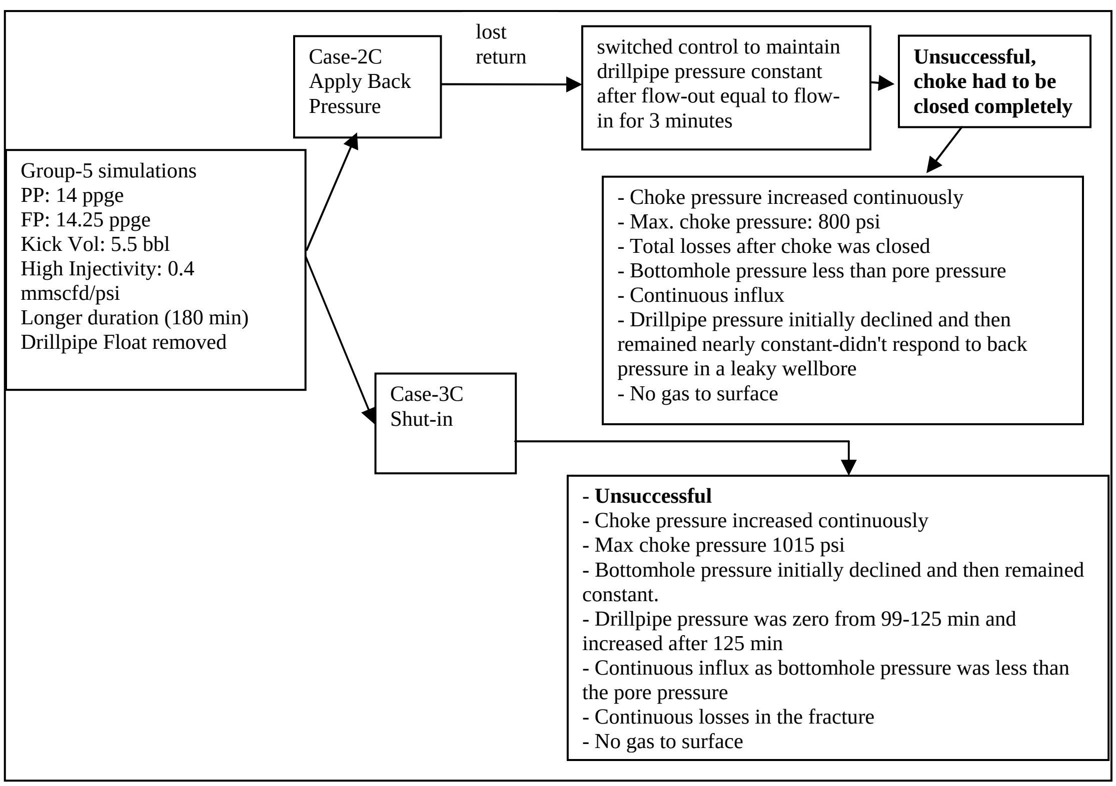

Figure 6.57: Comparison of group-5 simulations (case-2C and case-3C)

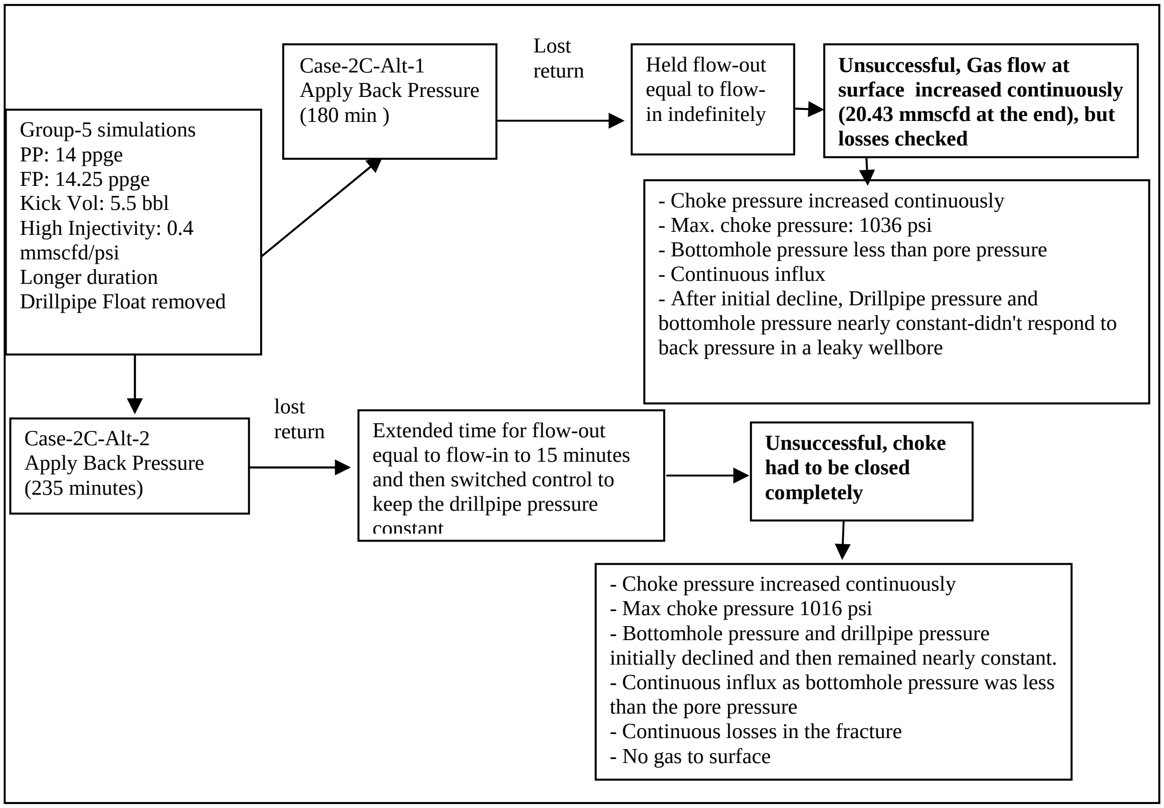

Figure 6.58: Comparison of group-5 simulations (case-2C-Alt-1 and case-2C-Alt-2)

The highlights of these simulation results are as follows:

1. The fracture injectivity at the shoe dominated the outcome of the initial reactions to a gas kick in a fractured wellbore. For higher fracture injectivity (0.4 mmscfd / psi) cases, bottomhole pressure could not be increased to equal the pore pressure by applying back pressure due to heavy losses in the fracture. Shutting-in the well with higher fracture injectivity also did not stop influx implying an underground blowout. Consequently, the influx continued in all simulations with high fracture injectivity. Conversely, a 5.5 bbl initial gas kick was successfully circulated out by keeping the drillpipe pressure constant in one simulation where the injectivity at shoe was small (0.0004 mmscfd / psi).

2. Using the choke to maintain the return flow equal to pumping rate over an extended period resulted in a continuous increase in gas flow rate at the surface representing surface blow-out in the case with high fracture injectivity.
3. Shut-in cases that caused formation breakdown into a high injectivity fracture experienced bottomhole pressure less than the mud hydrostatic for some time. This resulted in a zero drillpipe pressure if no drillstring float was present. Therefore, drillpipe pressure could be used to identify a decrease in bottomhole pressure due to simultaneous feed-in and losses. The drill pipe pressure started to increase after some time, and increased gradually while the bottomhole pressure was nearly constant. It seems that gas had entered the drillpipe when the fluid level in the drillpipe had dropped and then migrated upwards resulting in an increase in the drillpipe pressure.
4. Higher drillpipe pressure and choke pressure were observed for larger size kick during well control, as expected.
5. In general, somewhat higher choke pressures were recorded versus time for the shut-in reaction than for the ‘apply back pressure’ option in these simulations. This is a result of the annulus frictional pressure during continuous circulation in the back pressure reaction.

6.9 Simulation Results: Detection of False Alarm

A simulation was run, where back pressure was applied through the choke without any noticeable kick in the well. The purpose of this simulation was to observe the well behavior for establishing a baseline without a kick. It also provided the opportunity to investigate ways to identify a false alarm of a kick. The input data for this simulation was same as the group 6 simulations. At 4475 ft (25 ft shallower than the kick zone), drilling was discontinued to check whether the well was underbalanced or not. The well was circulated for about 5 minutes, and thereafter, the choke was gradually closed to increase the bottomhole pressure by increasing the choke pressure. The choke pressure was raised by about 100 psi, and thereafter, the choke opening size was held constant at 77 % for about 5 minutes before ending the simulation. The response of the return flow rate, drillpipe pressure and the choke pressure to the choke adjustments were monitored during the simulation.

Figure 6.59 shows a composite plot of flow rate-in, flow rate-out, choke pressure and choke opening for this simulation run. Initially, the simulated return flow rate declined to a rate of about 994 gpm while circulating after drilling stopped, see label on Figure 6.62. The overall return flow rate then decreased slightly in response to raising the choke pressure. This response was expected due to fluid compressibility. Once a constant choke setting was reached, the return flow rate increased to about 994 gpm, the flow rate before the choke adjustment, indicating no lost returns. The choke pressure, as well as the return flow-rate stabilized and remained relatively constant when the choke position was held constant implying a steady state condition in the wellbore without any gas influx or lost returns.

Figure 6.60 shows the response of the drillpipe pressure and the choke pressure to the choke opening size. The drillpipe pressure gradually increased with the increase in back pressure. It then remained constant when the choke pressure and the choke opening were held constant indicating there is no gas migrating.

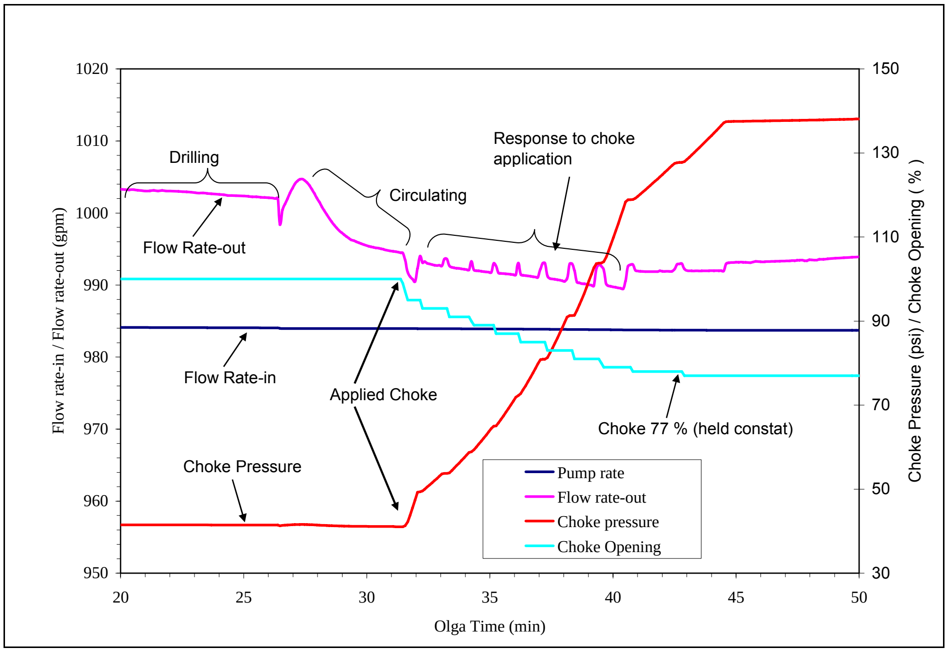

Figure 6.59: Response of choke pressure and flow rate-out to choke adjustment (case-0, false alarm detection)

This behavior is essentially as expected and lends credibility to the simulations. However, no conclusive diagnostic procedures for confirming the occurrence of a kick were identified like a flow check does in conventional drilling.

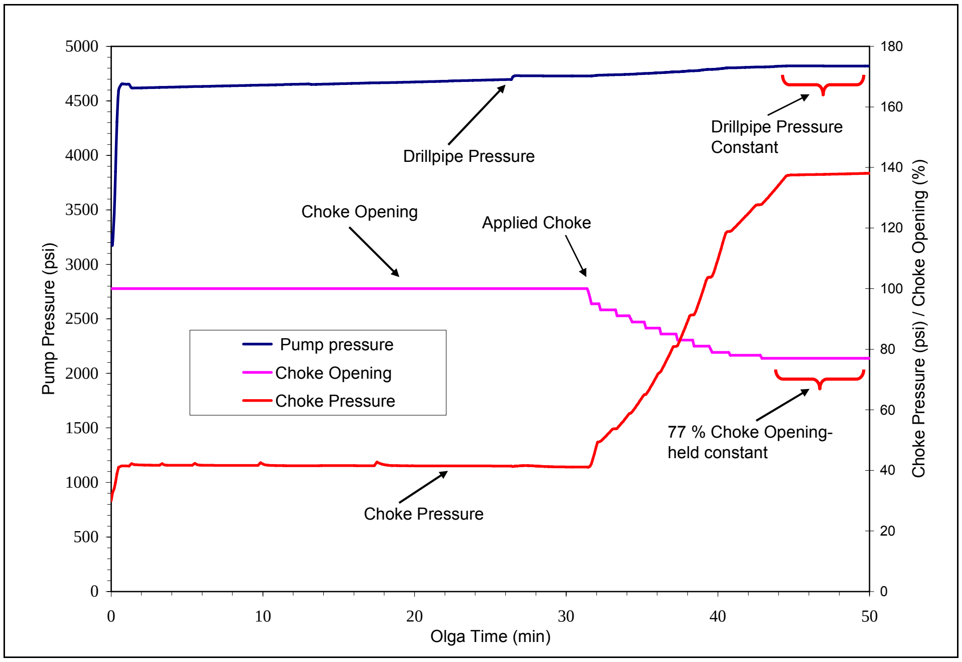

Figure 6.60: Response of drillpipe pressure and choke pressure to choke adjustment (case-0, false alarm detection)

7. DISCUSSION OF SIMULATION RESULTS

Additional discussion considering all of the simulations in the two preceding chapters is needed to draw more general conclusions about the effectiveness of each of the simulated initial reactions.

7.1 Additional Influx after Initial Reaction

One criteria for comparing alternative reactions was expected to be minimizing the additional influx after the initial reactions. This criteria was not used in judging the effectiveness of the alternative initial reactions. Choke adjustments for the ‘apply back pressure’ and the mud pump speed adjustments for the ‘increase mud flow rate’ reactions are interactive with the change in the difference between the return flow rate and the pumping rate, making them dependent on the operator’s reaction. Conversely shutting-in the well is almost instantaneous except that a rapid increase in the formation feed-in rate was observed after the pump was shut-in because of decrease in bottomhole pressure consequent to loss of annular frictional pressures. In practice, this can be avoided if a pump shutdown procedure appropriate to the CBHP method of MPD is followed, but that is also operator dependent. No attempt was made to overcome this operator dependency for a consistent comparison,

7.2 Limitation of the ‘Increase Mud Flow Rate’ Reaction

The ‘Increase mud flow rate’ reaction effectively stopped formation fluid influx in a 6 inch slim hole with an intact wellbore due to the high wellbore frictional pressures in the narrow annular clearance. However, despite a narrow annular geometry, this reaction was not successful in this hole in stopping the influx in a simulation with lost returns from below the kick zone. Because of losses, the required ECD to adequately increase the wellbore pressure to overbalance the pore pressure was not achieved. Also, the ‘increase mud flow rate’ reaction is unlikely to be effective in a big size hole with larger annular clearance due to pump limitation. Frictional pressure losses due to turbulent flow in the annulus is nearly proportional to the square of the annular velocity and inversely proportional to the annular clearance[43]. The annular velocity is inversely proportional to the annular cross sectional area. Therefore a very large flow rate is required to adequately increase the annular frictional pressure to overbalance the pore pressure. Also, the big size holes are normally shallow, and therefore, effective increase in bottomhole pressures due to annulus frictional pressures is much less than in deeper small size holes.

High standpipe pressure is the common limitation on increasing the pump rate for a dynamic kill because of large frictional pressure losses inside the drillstring. The frictional pressure losses inside the drillstring are nearly proportional to the square of the fluid velocity inside the pipe and inversely proportional to the inside diameter of the pipe[43]. The fluid velocity inside the pipe is significantly higher than in the large annulus because of smaller cross sectional area. Therefore, standpipe pressure rapidly increases with the increase in pump rate, and the pressure rating of the surface equipment or the mud pump becomes the limiting factor for adequately increasing the flow rate for a dynamic kill. In a big, 17-1/2 inch hole, this reaction was not successful, however, boundary for hole size for which this reaction would be successful was not determined in this study.

7.3 Increase Back Pressure Reaction in a Non-Intact Wellbore

Identifying occurrence of a formation fracture, causing lost returns during a kick is difficult during a back pressure reaction. In general, a return flow rate less than the pumping rate is indicative of lost returns. In an intact wellbore, the return flow rate being equal to the pumping rate will indicate stoppage of influx. However, if the wellbore is not intact, then the decrease of return flow rate to equal with the pumping rate during back pressure application can not be considered as a positive indication of stoppage of the influx. During back pressure application, if the shoe pressure exceeds the fracture pressure before the bottomhole pressure is adequately increased to over balance the pore pressure, shoe breakdown will occur, which will induce lost returns in the well. A simultaneous loss and gain will begin in the well. The return flow rate will continue to be more than the pumping rate unless the loss rate exceeds the influx rate. Therefore, the losses will probably not be recognized immediately at surface.

Depending on the wellbore fluid compressibility factor, the return flow rate may also be less than the pumping rate if a higher back pressure is applied than required after stoppage of influx in an intact wellbore. Therefore, the return flow rate being slightly less then the pumping rate (considering small effect of fluid compressibility) may not be indicative of lost returns.

Hence, comparing return flow rate with the pumping rate will not conclusively distinguish between a stoppage of influx or formation breakdown or shrinkage if the wellbore is not intact.

Two different strategies for the choke adjustments were considered in the simulations when the return flow rate was reduced to a value less than the pumping rate during back pressure application: (1) Adjusting the choke to try to equalize the return flow rate with the pumping rate and (2) Adjusting the choke to keep the drillpipe pressure constant following driller's method[41] of well control. In simulations with strategy 1, an uncontrolled flow of gas at the surface was observed. During this process, the average liquid return flow rate was nearly equal to the pumping rate implying no lost returns in the well. In the simulations with the strategy 2, the lost returns were almost instantaneously confirmed by a rapid and continued decline in return flow rate as the back pressure was increased continuously, attempting to keep the drillpipe pressure constant.

Strategy 1 is not advisable as the influx may continue into the wellbore with progressively higher rate and a surface blowout situation arises. Strategy 2 is perhaps a better option as it identifies a formation fracture, or if the wellbore is intact, presumably it can circulate out the gas by maintaining the bottomhole pressure constant without any additional influx.

In the simulations with the strategy 2 in a non-intact wellbore, two different results were observed: (1) The complete closure of the choke while trying to maintain the continuously declining drillpipe pressure and (2) able to circulate out the gas influx with partial return. In situation 1, an underground blowout was initiated with a continuous formation feed-in and a total mud loss in the openhole. The implication of an underground blowout versus an uncontrolled flow of gas at the surface in MPD needs to be assessed in each case to determine the better strategy.

7.4 Shut-in Reaction in Non-Intact Wellbore

Identifying lost returns in the shut-in option is also difficult as the choke pressure is the only observable parameter after the well is shut-in if the float is installed in the BHA. As seen in the simulations, the choke pressure continued to increase after closing the well in ‘shut-in’ reactions to gas kicks, and lost returns could not be conclusively detected from the choke pressure build up. In one simulation with lost returns below the kick zone, the float was removed from the BHA to observe the change in the drillpipe pressure after the well was shut-in. It was observed that the drillpipe pressure did not respond to the choke pressure build up in a non-intact wellbore after the well was shut-in. The drillpipe pressure was zero during the choke pressure build up, which may be considered as a strong evidence of lost returns in the well.

A similar trend i.e. zero drillpipe pressure was observed in the simulation with 'shut-in' reaction to a gas kick with lost returns above the kick zone. However, in this case, the drillpipe pressure subsequently began to increase, whereas the bottomhole pressure stayed nearly constant. This phenomenon may be attributed to the entry of gas inside the drillstring and subsequent migration up the drillstring for the reason explained in section 6.6.2.

Therefore, lost returns may be detectable by observing the trend in drillpipe pressure if a float is not installed in the BHA. However, use of float(s) is recommended in managed pressure drilling to prevent flow through the drillpipe during pipe connections. Therefore an effective procedure for repeatedly bumping the float is required to monitor drillpipe pressure

7.5 Sensitivity to Formation Fracture Injectivity

The fracture injectivity index is a dominant factor in well control once lost returns occur. In simulations with a 17-1/2 inch hole and high fracture injectivity (0.4 mmscfd / psi) at the shoe, well control using the back pressure reaction was not successful for a small, 5.5 bbl gas kick. In these simulations, the choke had to be completely closed while trying to maintain drillpipe pressure constant with increasing back pressure after flow-out equalized with flow-in. Conversely, in a simulation in the same hole size, with low fracture injectivity at the shoe (0.0004 mmscfd / psi), a 5.5 bbl gas kick was successfully circulated out despite minor lost returns.

7.6 Evaluation of Effectiveness of Initial Reactions

The effectiveness of initial reactions to address the basic well control issues i.e. ability to stop the formation feed-in, prevent lost returns, confirm stoppage of influx and identify lost returns is summarized in Table 7.1, 7.2, 7.3 and 7.4 respectively based on all of the simulation results.

Table 7.1: Effectiveness of initial reactions to stop formation feed-in

Shut-in		Apply Back Pressure		Increase Flow Rate	
Intact Wellbore	Non-intact Wellbore	Intact Wellbore	Non-intact Wellbore	Intact Wellbore	Non-intact Wellbore
Effective	Does not stop influx	Effective	Inconclusive, as both success and failure of stopping the influx were observed in the simulations. The results obtained were sensitive to fracture injectivity index and the strategy of choke adjustments e.g. attempting to maintain drillpipe pressure constant after flow-out equaled flow-in versus forcing flow-out equal to flow-in for extended duration.	Effective in slim hole, but not in large hole as necessary ECD could not be generated due to pump limitation.	Not successful for these simulations. Necessary ECD to over balance the formation pressure could not be generated due to pump limitation.

Table 7.2: Effectiveness of initial reactions to prevent lost returns

Shut-in	Apply Back Pressure	Increase Flow Rate
Most susceptible to lost returns because of high casing pressure	Less risk than shut-in option because of lower casing pressure. In these simulations, if flow-out is forced to equal flow-in for extended period, an uncontrolled flow of gas at surface may occur and lost returns may stop.	Minimum risk of lost returns above the kick zone because of minimum surface pressure.

Table 7.3: Effectiveness of initial reactions to confirm stoppage of formation feed-in

Shut-in		Apply Back Pressure		Increase Flow Rate	
Intact Wellbore	Non-intact Wellbore	Intact Wellbore	Non-intact Wellbore	Intact Wellbore	Non-intact Wellbore
A stabilized casing pressure after initial build up will indicate stoppage of influx. However, this method is not straight forward because gas migration may start quickly after stoppage of influx resulting in increase in casing pressure. Drillpipe pressure increasing at the same rate as the casing pressure after initial build up apparently indicates stoppage of influx. Failure to stop influx can be concluded from a rising casing pressure and a constant drillpipe pressure.	Does not stop influx	Effective as flow-out equal to flow-in will indicate stoppage of influx.	Not effective as explained at section 7.3.	Effective as flow-out equal to flow-in will indicate stoppage of influx.	Not effective. Explanation at section 7.3 also applicable for this reaction.

Table 7.4: Effectiveness of initial reactions to identify lost returns

Shut-in	Apply Back Pressure	Increase Flow Rate
Effective by observing decreasing trend of drillpipe pressure if float is not installed or float is bumped regularly. See explanation at section 7.4	Not effective for identifying lost returns exactly when it starts as explained in section 7.3. However, lost returns can be identified when flow-out becomes less consistently than flow-in.	Not effective for identifying lost return exactly when it starts. Explanation given in section 7.3 about identifying lost returns by back pressure reaction based on simulation results is also applicable for this reaction. The lost return should be identified when flow-out is consistently less than flow-in. However, no simulations undertaken with this reaction resulted in flow-out less than flow-in.

8. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

8.1 Summary

Managed pressure drilling, MPD, with a constant bottomhole pressure is a method that increases the feasibility of successfully drilling wells with a narrow margin between the pore pressure and the fracture pressure. However, the narrow margin can increase the likelihood of taking a kick and of causing lost returns while controlling the kick. The conventional well control method relies on mud hydrostatic pressure for primary control of the well. However, managed pressure drilling typically uses a mud weight that is less than the pore pressure gradient and utilizes the wellbore frictional pressures and / or back pressure to overbalance the pore pressure. Therefore, alternative well control procedures are required for managed pressure drilling.

The objective of this project is to determine the best initial response, or reaction to a kick taken while conducting MPD operations. The effectiveness of the initial response to a kick was judged based on minimizing casing pressure, ability to stop formation feed-in with minimum additional gain, ability to verify that formation feed-in was stopped and ability to identify lost returns.

A multiphase transient flow simulator, UbitTS™ was used to study the effectiveness of three different initial responses to a kick taken during managed pressure drilling operations, namely (1) shut-in the well (2) increase mud pump rate and (3) apply back pressure. Descriptions of actual or planned MPD wells were provided by the industry sponsors and used to build various representative simulation cases. Hole sections from two wells, one a large 17-1/2 inch and one a slim 6 inch, were selected. Kicks in these geometries were then simulated to study the effectiveness of alternative initial reactions in different kick scenarios. The kick scenarios were varied by changing the kick volumes, the type of reservoir fluid (oil or gas), the type of drilling mud (water-based or oil-based), the differential pressure at the kick zone and the fracture injectivity.

Gas and oil kicks were simulated while drilling through a high pressure sand in a 6 inch slim hole. The sensitivity of casing pressures to initial kick volumes, types of reservoir fluid (oil or gas) and types of drilling fluid (water-based or oil-based) during initial reactions were studied. A well control scenario with a kick taken due to lost returns below the kick sand was simulated in this hole, and the effectiveness of the initial reactions was studied. A few simulations were run for longer duration to study the effect of the initial reactions on the feasibility of well control for this scenario

Gas kicks were simulated in a 17-1/2 inch hole while drilling through a high pressure sand, and the effectiveness of each initial reaction in an intact wellbore was studied. Also, simulations were run in this hole section with kicks taken from a higher pressure sand that would result in an induced fracture at shoe during some initial reactions. Severity of the well control scenarios was also varied by changing the initial kick volume and the injectivity index at the fractured formation. Effectiveness and feasibility of well control with alternative initial reactions in a non-intact wellbore were studied with longer simulation runs.

The effect of the length of time to maintain flow-out equal to flow-in in selecting the drillpipe pressure to hold constant while circulating out a kick was studied in longer simulations using the back pressure reaction. The ability to identify lost returns and underground transfers of formation fluid was also studied for the different initial reactions.

Base case simulations were also conducted in 17-1/2 inch and 6 inch hole without any noticeable increase in return flow rate during drilling to establish a baseline well response for comparison to cases with kicks and to investigate the ability to identify a false alarm of a kick. In these simulations, back pressures were applied by reducing the choke opening and changes in the return flow rates were monitored.

8.2 Conclusions

The following conclusions are based on review and analysis of the simulations described in the preceding section. These conclusions may not apply to all MPD situations.

1. The casing pressure versus time is higher for ‘shut-in’ reactions than for ‘back pressure’ and the ‘increase pump rate’ reactions to oil and gas kicks in an intact wellbore.
2. Casing pressure versus time is the lowest for the ‘increase pump rate’ reaction to oil and gas kicks in an intact wellbore.
3. A larger initial kick volume results in a higher casing pressure during the initial reactions.
4. The ‘increase pump rate’ reaction is most likely to be effective for stopping formation fluid influx when applied to slim hole operations with an intact wellbore.
5. Stopping formation feed-in in a large size hole with increased pump rate is unlikely to be successful because pump and surface equipment capacities and the small AFP losses limit the increase in bottomhole pressure that can be achieved.

6. Maintaining flow-out equal to flow-in for an extended time in the back pressure reaction to a gas kick in a non-intact wellbore may lead to uncontrolled flow of gas at the surface.
7. Attempting to maintain drillpipe pressure constant after the flow-out becomes equal to the flow-in in the back pressure reaction may lead to underground blowout with continuous influx and total lost returns, if the wellbore is not intact.
8. Identifying lost returns by comparing flow-out with flow-in during the back pressure reaction may be difficult as explained in section 7.3.
9. Lost returns may be identified in the shut-in reaction by a decreasing trend in drillpipe pressure after the well is shut-in provided a drillpipe float is not installed or an effective procedure for bumping the float is used. A zero drillpipe pressure after the well is shut-in is a strong indication of lost returns as explained in sections 6.6.2 and 7.4.
10. The fracture injectivity index of a lost circulation zone or induced fractures is very important to the success of well control once lost returns have occurred. A low fracture injectivity index may allow the increase in bottomhole pressure needed to successfully circulate out a kick despite partial lost returns.

8.2.1 Best Initial Reaction

The objective of defining the best initial reaction to a kick during MPD operations has not been achieved. There is no obvious best single reaction based on the work herein. Nevertheless the following tentative conclusions have been reached.

- The 'increase mud flow rate' has a major advantage for situations where it might provide enough increase in bottomhole pressure to stop formation flow because it results in the minimum casing and shoe pressures. Therefore, it should minimize the risk of lost returns or surface equipment failure.
- The 'apply back pressure' response has a similar but smaller advantage versus the 'shut-in' option because of the ECD due to circulation. However, in cases where the wellbore does not remain intact, reliable ways of identifying the loss of returns and avoiding unintentional formation flow to the surface have not been defined in this study.
- The 'shut-in' reaction generally results in the highest casing and casing shoe pressures. Therefore, it may be most likely to cause loss of returns before stopping formation flow which could cause an underground transfer with continuous influx. Nevertheless, it is probably the least likely to unintentionally allow formation fluid flow to the surface or to cause loss of significant mud volume.

8.3 Recommendations

1. Additional simulations in common intermediate size holes, particularly 12-1/4" and 8-1/2", of representative MPD wells should be conducted to study the effectiveness of different initial kick responses in different well geometry. Specifically, simulations should be undertaken to investigate the range of mud flow rates and standpipe pressures required for dynamic kills in these hole sizes.
2. Simulations should be run to study the effect of simultaneous or sequential application of back pressure and increase of mud flow rate, especially when

increasing mud flow rate alone to the maximum pump discharge capacity is not successful in stopping the influx. The combination of back pressure, and increased pump rate should provide maximum bottomhole pressure, at least for some well geometries.

3. Simulations should be run to study the impact of the productivity index on the effectiveness of different initial reactions to kicks.
4. Longer simulations with the 'back pressure reaction' should be undertaken with a gas kick in an intact wellbore to see if the gas can be circulated out while keeping the drillpipe pressure constant without taking additional influx or other complications.
5. Simulations should be undertaken with oil kicks similar to gas kicks with an induced fracture (1) above the kick zone and (2) below the kick zone during initial reactions for identifying differences when no gas migration effect exists.
6. If the 'increase mud pump rate' reaction is desired for MPD well control, then detailed hydraulics calculations should be performed during the MPD well design to determine the required capacity of the mud pump and other surface equipment to provide the desired increase in bottomhole pressure. Use of a larger size drillpipe to reduce the annular clearance for generating higher annulus frictional pressure and reducing the frictional pressure losses inside the drillstring should be considered during the MPD well design.
7. Several upgrades to the UbitTS™ program are recommended. The program does not provide pit gain in real time. In this study, kick volumes were approximated from 5 minute average loss / gain real time data provided by the

program. Also, UbitTS^{TM} does not allow a hole size greater than the internal diameter (ID) of the previous casing. Therefore, drilling with a bicenter bit or using an underreamer to drill a hole of bigger diameter than the previous casing ID can not be simulated in this program. Drilling with a bicenter bit or an underreamer is a common practice in MPD wells. The UbitTS^{TM} program uses a Newtonian drilling fluid rehological model for calculation of frictional pressures in the well, however, most drilling fluids are non-Newtonian. Therefore, it is recommended that UbitTS^{TM} be upgraded to correct these shortcomings and that other well control simulation programs be evaluated for providing more accurate results in future simulations.

8. The use of a circulation sub in the BHA for diverting the flow in the annulus through the side ports, bypassing the bit nozzles, should be investigated as a means to reduce the pump pressure and facilitate higher pump rates to increase the ability to achieve a successful kill with the increase pump rate method.
9. The ‘shut-in’ and ‘increase pump rate’ responses should be applied in simulations when no kick exists to indicate whether either of these responses might provide a more conclusive basis for identifying a false kick alarm.

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APPENDIX A1: SIMULATOR INPUT DATA FOR WELL X

UNDERBALANCED DRILLING TRAINING SIMULATOR REPORT
==

GENERAL
Filename: C:\Documents and Settings\adas2\My Documents\Asis\UBD_AUX\WELL X\Case1\wellXcase1.ubd
OLGA 2000 engine: olga2000-4.16.exe
DRILLSTRING
- Average length of joint: 30 ft
- Average length of stand: 90 ft
- Bitnozzle area: 0.45 in2
- DP
  - ID: 3.34 in
  - OD: 4 in
  - Length: 11500 ft
  - Weight/Length: 14 Lb/ft
  - Type: Drillpipe
- DP
  - ID: 2.764 in
  - OD: 3.5 in
  - Length: 5646 ft
  - Weight/Length: 13.3 Lb/ft
  - Type: Drillpipe
- HWT
  - ID: 2.25 in
  - OD: 3.5 in
  - Length: 360 ft
  - Weight/Length: 23.4 Lb/ft
  - Type: Drillpipe
- DC
  - ID: 2.25 in
  - OD: 4.75 in
  - Length: 360 ft
  - Weight/Length: 46.7 Lb/ft
  - Type: Drillpipe
- MWD
  - ID: 2.25 in
  - OD: 4.75 in
  - Length: 30 ft
  - Weight/Length: 46.7 Lb/ft
  - Type: MWD
- Float
  - ID: 2.25 in
  - OD: 4.75 in

Length:	3 ft
Weight/Length:	46.7 Lb/ft
Type:	Floatsub
Bit	
OD:	6 in
Length:	1 ft
Weight/Length:	46.7 Lb/ft
Type:	Bit
WELL GEOMETRY	
Water depth:	0 ft
Annular injection	
Type:	NONE
Allow backflow:	NO
Depth:	0 ft
Diameter:	0 in
Thickness:	0 in
Temperature at rigfloor:	70 F
Temperature at seabed:	32 F
Bottom hole temperature:	165 F
CASING	
Riser	
ID:	8.755 in
OD:	9.625 in
Top:	0 ft
Bottom:	3032 ft
Cement top:	0 ft
csg	
ID:	6.094 in
OD:	7 in
Top:	3032 ft
Bottom:	12160 ft
Cement top:	11800 ft
csg	
ID:	6.1 in
OD:	7 in
Top:	12160 ft
Bottom:	14150 ft
Cement top:	12160 ft
SURVEY DATA	
Data 1	
Measured depth:	8300 ft
TVD depth:	8300 ft
Inclination:	0
Azimuth:	0
Data 2	
Measured depth:	11186 ft

	TVD depth:	10970.16 ft
	Inclination:	22.3
	Azimuth:	25.5
Data 3		
	Measured depth:	14033 ft
	TVD depth:	13128.56 ft
	Inclination:	40.7
	Azimuth:	51
Data 4		
	Measured depth:	14150 ft
	TVD depth:	13216.77 ft
	Inclination:	41.07
	Azimuth:	50.76
Data 5		
	Measured depth:	14190 ft
	TVD depth:	13246.47 ft
	Inclination:	42.06
	Azimuth:	51.79
Data 6		
	Measured depth:	14350 ft
	TVD depth:	13365.26 ft
	Inclination:	42.06
	Azimuth:	51.79
Data 7		
	Measured depth:	15014.5 ft
	TVD depth:	13632.35 ft
	Inclination:	66.3
	Azimuth:	44.51
Data 8		
	Measured depth:	17021.87 ft
	TVD depth:	14439.21 ft
	Inclination:	66.3
	Azimuth:	44.51
Data 9		
	Measured depth:	17398.41 ft
	TVD depth:	14655.19 ft
	Inclination:	55
	Azimuth:	44.51
Data 10		
	Measured depth:	17638.96 ft
	TVD depth:	14816.83 ft
	Inclination:	47.78
	Azimuth:	44.51
Data 11		
	Measured depth:	17791.75 ft
	TVD depth:	14928.21 ft

	Inclination:	43.2
	Azimuth:	44.51
Data 12		
	Measured depth:	17888.96 ft
	TVD depth:	14999.07 ft
	Inclination:	43.2
	Azimuth:	44.51
Data 13		
	Measured depth:	17900 ft
	TVD depth:	15007.12 ft
	Inclination:	43.2
	Azimuth:	44.51

PUMP DATA

Suction tank		
	Min rate:	0 USgal/min
	Max rate:	1000 USgal/min
	Max pressure:	5360 psia
	Volume per stroke:	0.122 bbl
Pill tank		
	Min rate:	0 USgal/min
	Max rate:	1000 USgal/min
	Max pressure:	5360 psia
	Volume per stroke:	0.122 bbl
Drillstring injection		
	Min rate:	0 MMSCF/d
	Max rate:	5 MMSCF/d
	Max pressure:	3500 psia
Annular injection		
	Min rate:	0 MMSCF/d
	Max rate:	0 MMSCF/d
	Max pressure:	0 psia

FLUID PROPERTIES

Suction tank		
	Base fluid:	Water
	Fluid details:	NONE
	Tank capacity:	5000 bbl
	Density:	13.2 Lb/USgal
	Viscosity:	38 cp
Pill tank		
	Base fluid:	Water
	Fluid details:	NONE
	Tank capacity:	5000 bbl
	Density:	13.2 Lb/USgal
	Viscosity:	38 cp
Drillstring		
	Base fluid:	Nitrogen

Annulus
Base fluid:
RESERVOIR
Form-1
Fluid type: Gas
Rock strength: Soft
Measured depth top: 14150 ft
Measured depth bottom:14410 ft
Pore pressure: 8041 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 10398 psia
Injection pressure: 10398 psia
Std PI injection: 0.0004 MMSCF/psi-d
Form-2
Fluid type: Gas
Rock strength: Soft
Measured depth top: 14410 ft
Measured depth bottom:14754 ft
Pore pressure: 8222.24 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 10556 psia
Injection pressure: 10556 psia
Std PI injection: 0.0004 MMSCF/psi-d
Form-3
Fluid type: Gas
Rock strength: Soft
Measured depth top: 14754 ft
Measured depth bottom:15135 ft
Pore pressure: 8627.84 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 10728 psia
Injection pressure: 10728 psia
Std PI injection: 0.0004 MMSCF/psi-d
Form-4
Fluid type: Gas
Rock strength: Soft
Measured depth top: 15135 ft
Measured depth bottom:15632 ft
Pore pressure: 8984.35 psia
Std PI production: 0.4286 MMSCF/psi-d

GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 10907 psia
Injection pressure: 10907 psia
Std PI injection: 0.0004 MMSCF/psi-d

Msand

Fluid type: Gas
Rock strength: Soft
Measured depth top: 15632 ft
Measured depth bottom:16130 ft
Pore pressure: 9901 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 11123 psia
Injection pressure: 11123 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-6

Fluid type: Gas
Rock strength: Soft
Measured depth top: 16130 ft
Measured depth bottom:16627 ft
Pore pressure: 9805.95 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 10000 psia
Injection pressure: 10000 psia
Std PI injection: 0.4286 MMSCF/psi-d

Form-7

Fluid type: Gas
Rock strength: Soft
Measured depth top: 16627 ft
Measured depth bottom:17106 ft
Pore pressure: 10003.96 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 11606 psia
Injection pressure: 11606 psia
Std PI injection: 0.0004 MMSCF/psi-d

Nsand(depltd)

Fluid type: Gas
Rock strength: Soft
Measured depth top: 17106 ft
Measured depth bottom:17394 ft

Pore pressure: 9414 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 11494 psia
Injection pressure: 11494 psia
Std PI injection: 0.0004 MMSCF/psi-d

Osand(depltd)

Fluid type: Gas
Rock strength: Soft
Measured depth top: 17394 ft
Measured depth bottom:17490 ft
Pore pressure: 8590 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 11214 psia
Injection pressure: 11214 psia
Std PI injection: 0.0004 MMSCF/psi-d

Osand

Fluid type: Gas
Rock strength: Soft
Measured depth top: 17490 ft
Measured depth bottom:17792 ft
Pore pressure: 9959 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 12044 psia
Injection pressure: 12044 psia
Std PI injection: 0.0004 MMSCF/psi-d

Osand

Fluid type: Gas
Rock strength: Soft
Measured depth top: 17792 ft
Measured depth bottom:17900 ft
Pore pressure: 10202 psia
Std PI production: 0.4286 MMSCF/psi-d
GOR: 4000 SCF/STB
Watercut: 0 %
Initiation pressure: 12277 psia
Injection pressure: 12277 psia
Std PI injection: 0.0004 MMSCF/psi-d

SURFACE EQUIPMENT

Response delay for valves: 1 s
Rotating control max pressure:3000 psia

Return line diameter:	6 in
Return line length:	100 ft
Choke max diameter:	3 in
Return oil capacity:	0 bbl
Return water capacity:	0 bbl
Gas outlet diameter:	0 in
Gas outlet length:	0 ft
Gas outlet backpressure:	0 psia
UBD separator	
Type:	NONE
Backpressure:	14.7 psia
SPECIAL PROBLEMS	NONE
SIMULATION OPTIONS	
Liquid suction rate:	150 USgal/min
Liquid pill rate:	0 USgal/min
Drillstring gas rate:	0 MMSCF/d
Annular gas rate:	0 MMSCF/d
Bit depth:	15582 ft
PVT file name:	gas.tab
Restart file name:	
Restart start time:	0 s
Screen time:	1 s
Sampling time:	5 s
Variables to track:	
	OLGA timestep
	OLGA speed
	Drillstring: Gas flow
	Annular injection: Gas flow
	Suction tank: Liquid flow
	Pill tank: Liquid flow
	Separator: Pressure
	Separator: Liquid level
	Bypass line: Total flow
	Return choke: Opening
	Suction tank: Volume
	Pill tank: Volume
	DrillBit: Depth
	Drillstring inlet: Gas flow
	Drillstring inlet: Liquid flow
	Drillstring inlet: Pressure
	Return choke: Upstream pressure
	Separator: Inlet gas flow
	Separator: Inlet liquid flow
	Drillbit: Drillstring temperature
	Drillbit: Annular pressure
	Drillbit: Drillstring pressure

Drillbit: Total volume flow
Drillbit: Penetration rate
Average: Gas rate injected
Average: Gas rate produced
Average: Gas rate gained/lost
Average: Oil rate injected
Average: Oil rate produced
Average: Oil rate gained/lost
Average: Water rate injected
Average: Water rate produced
Average: Water rate gained/lost
Formation: Total flow
Drillbit: Drilled depth
Bleed off: Valve opening
Drillbit: Annular section pressure
Annular injection: Surface pressure
Annular injection: Down hole pressure
Annular injection: Down hole gas flow
Separator: Setpoint pressure

PRIVILEGES

User access level: Student

APPENDIX A2: SIMULATOR INPUT DATA FOR WELL Z

UNDERBALANCED DRILLING TRAINING SIMULATOR REPORT
==

GENERAL
Filename:C:\Documents and Settings\adas2\My Documents\Asis\UBD_AUX\WELL Z\13ppg_kickzone\case-1\17.5_hole.ubd
OLGA 2000 engine: olga2000-4.16.exe
DRILLSTRING

Average length of joint:	30 ft
Average length of stand:	90 ft
Bitnozzle area:	0.75 in2
DP	
ID:	4.276 in
OD:	5 in
Length:	4002 ft
Weight/Length:	19.5 Lb/ft
Type:	Drillpipe
HW	
ID:	3 in
OD:	5 in
Length:	180 ft
Weight/Length:	50 Lb/ft
Type:	Drillpipe
DC	
ID:	2.8 in
OD:	6.5 in
Length:	180 ft
Weight/Length:	100 Lb/ft
Type:	Drillpipe
DC	
ID:	3 in
OD:	9 in
Length:	360 ft
Weight/Length:	196 Lb/ft
Type:	Drillpipe
MWD	
ID:	3 in
OD:	9 in
Length:	30 ft
Weight/Length:	196 Lb/ft
Type:	MWD
Float	
ID:	3 in
OD:	9 in

Length:	3 ft
Weight/Length:	196 Lb/ft
Type:	Floatsub
Bit	
OD:	17.5 in
Length:	1 ft
Weight/Length:	196 Lb/ft
Type:	Bit

WELL GEOMETRY

Water depth:	0 ft
Annular injection	
Type:	NONE
Allow backflow:	NO
Depth:	0 ft
Diameter:	0 in
Thickness:	0 in
Temperature at rigfloor:	70 F
Temperature at seabed:	32 F
Bottom hole temperature:	130 F

CASING

Casing	
ID:	18.73 in
OD:	20 in
Top:	0 ft
Bottom:	3280 ft
Cement top:	0 ft

SURVEY DATA

Data 1	
Measured depth:	4756 ft
TVD depth:	4756 ft
Inclination:	0
Azimuth:	0

PUMP DATA

Suction tank	
Min rate:	0 USgal/min
Max rate:	1620 USgal/min
Max pressure:	6285 psia
Volume per stroke:	0.122 bbl
Pill tank	
Min rate:	0 USgal/min
Max rate:	1620 USgal/min
Max pressure:	6285 psia
Volume per stroke:	0.122 bbl
Drillstring injection	
Min rate:	0 MMSCF/d
Max rate:	5 MMSCF/d

Max pressure: 3500 psia

Annular injection

Min rate: 0 MMSCF/d

Max rate: 0 MMSCF/d

Max pressure: 0 psia

FLUID PROPERTIES

Suction tank

Base fluid: Water

Fluid details: NONE

Tank capacity: 5000 bbl

Density: 12.51 Lb/USgal

Viscosity: 38 cp

Pill tank

Base fluid: Water

Fluid details: NONE

Tank capacity: 5000 bbl

Density: 12.51 Lb/USgal

Viscosity: 38 cp

Drillstring

Base fluid: Nitrogen

Annulus

Base fluid:

RESERVOIR

Form-1

Fluid type: Gas

Rock strength: Soft

Measured depth top: 3280 ft

Measured depth bottom:3400 ft

Pore pressure: 1491 psia

Std PI production: 0.556456017 MMSCF/psi-d

GOR: 13761825.045634 SCF/STB

Watercut: 0 %

Initiation pressure: 2415 psia

Injection pressure: 2415 psia

Std PI injection: 0.0004 MMSCF/psi-d

Form-2

Fluid type: Gas

Rock strength: Soft

Measured depth top: 3400 ft

Measured depth bottom:3500 ft

Pore pressure: 1608 psia

Std PI production: 0.556456017 MMSCF/psi-d

GOR: 13761825.045634 SCF/STB

Watercut: 0 %

Initiation pressure: 2519 psia

Injection pressure: 2519 psia

Std PI injection: 0.0004 MMSCF/psi-d

Form-3

Fluid type: Gas
Rock strength: Soft
Measured depth top: 3500 ft
Measured depth bottom:3600 ft
Pore pressure: 1729 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 2611 psia
Injection pressure: 2611 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-4

Fluid type: Gas
Rock strength: Soft
Measured depth top: 3600 ft
Measured depth bottom:3700 ft
Pore pressure: 1834 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 2695 psia
Injection pressure: 2695 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-5

Fluid type: Gas
Rock strength: Soft
Measured depth top: 3700 ft
Measured depth bottom:3800 ft
Pore pressure: 1962 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 2780 psia
Injection pressure: 2780 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-6

Fluid type: Gas
Rock strength: Soft
Measured depth top: 3800 ft
Measured depth bottom:3900 ft
Pore pressure: 2094 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %

Initiation pressure: 2865 psia
Injection pressure: 2865 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-7

Fluid type: Gas
Rock strength: Soft
Measured depth top: 3900 ft
Measured depth bottom:4000 ft
Pore pressure: 2210 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 2960 psia
Injection pressure: 2960 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-8

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4000 ft
Measured depth bottom:4100 ft
Pore pressure: 2350 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 3057 psia
Injection pressure: 3057 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-9

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4100 ft
Measured depth bottom:4200 ft
Pore pressure: 2473 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 3144 psia
Injection pressure: 3144 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-10

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4200 ft
Measured depth bottom:4300 ft
Pore pressure: 2609 psia
Std PI production: 0.556456017 MMSCF/psi-d

GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 3243 psia
Injection pressure: 3243 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-11

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4300 ft
Measured depth bottom:4400 ft
Pore pressure: 2772 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 3331 psia
Injection pressure: 3331 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-12

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4400 ft
Measured depth bottom:4500 ft
Pore pressure: 2894 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 3432 psia
Injection pressure: 3432 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-13

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4500 ft
Measured depth bottom:4600 ft
Pore pressure: 3042 psia
Std PI production: 0.556456017 MMSCF/psi-d
GOR: 13761825.045634 SCF/STB
Watercut: 0 %
Initiation pressure: 3521 psia
Injection pressure: 3521 psia
Std PI injection: 0.0004 MMSCF/psi-d

Form-14

Fluid type: Gas
Rock strength: Soft
Measured depth top: 4600 ft
Measured depth bottom:4700 ft

Pore pressure:	3193 psia
Std PI production:	0.556456017 MMSCF/psi-d
GOR:	13761825.045634 SCF/STB
Watercut:	0 %
Initiation pressure:	3611 psia
Injection pressure:	3611 psia
Std PI injection:	0.0004 MMSCF/psi-d

Form-15

Fluid type:	Gas
Rock strength:	Soft
Measured depth top:	4700 ft
Measured depth bottom:	4756 ft
Pore pressure:	3348 psia
Std PI production:	0.556456017 MMSCF/psi-d
GOR:	13761825.045634 SCF/STB
Watercut:	0 %
Initiation pressure:	3769 psia
Injection pressure:	3769 psia
Std PI injection:	0.0004 MMSCF/psi-d

SURFACE EQUIPMENT

Response delay for valves:	1 s
Rotating control max pressure:	3000 psia
Return line diameter:	6 in
Return line length:	100 ft
Choke max diameter:	3 in
Return oil capacity:	0 bbl
Return water capacity:	0 bbl
Gas outlet diameter:	0 in
Gas outlet length:	0 ft
Gas outlet backpressure:	0 psia

UBD separator

Type:	NONE
Backpressure:	14.7 psia

SPECIAL PROBLEMS NONE

SIMULATION OPTIONS

Liquid suction rate:	800 USgal/min
Liquid pill rate:	0 USgal/min
Drillstring gas rate:	0 MMSCF/d
Annular gas rate:	0 MMSCF/d
Bit depth:	4340 ft
PVT file name:	gas.tab
Restart file name:	
Restart start time:	0 s
Screen time:	1 s
Sampling time:	5 s
Variables to track:	

OLGA timestep
OLGA speed
Drillstring: Gas flow
Annular injection: Gas flow
Suction tank: Liquid flow
Pill tank: Liquid flow
Separator: Pressure
Separator: Liquid level
Bypass line: Total flow
Return choke: Opening
Suction tank: Volume
Pill tank: Volume
DrillBit: Depth
Drillstring inlet: Gas flow
Drillstring inlet: Liquid flow
Drillstring inlet: Pressure
Return choke: Upstream pressure
Separator: Inlet gas flow
Separator: Inlet liquid flow
Drillbit: Drillstring temperature
Drillbit: Annular pressure
Drillbit: Drillstring pressure
Drillbit: Total volume flow
Drillbit: Penetration rate
Average: Gas rate injected
Average: Gas rate produced
Average: Gas rate gained/lost
Average: Oil rate injected
Average: Oil rate produced
Average: Oil rate gained/lost
Average: Water rate injected
Average: Water rate produced
Average: Water rate gained/lost
Formation: Total flow
Drillbit: Drilled depth
Bleed off: Valve opening
Drillbit: Annular section pressure
Annular injection: Surface pressure
Annular injection: Down hole pressure
Annular injection: Down hole gas flow
Separator: Setpoint pressure

PRIVILEGES

User access level: Student

VITA

Asis Kumar Das is from India. Asis is a graduate from Calcutta University, India, in mechanical engineering. Asis worked for Oil and Natural Gas Corporation Ltd, India, Essar Energy, Oman and Kuwait Drilling Company, Kuwait, as a drilling engineering professional for a total of 23 years. Asis began his graduate studies in petroleum engineering at Louisiana State University in January 2005. His technical interests include directional drilling, well engineering, well control and managed pressure drilling.